Pacific Gas and Electric Company

2022 GAS SAFETY PLAN

MARCH 15, 2022

Pacific Gas and Electric Company®

March 15, 2022

Dear Reader,

It is our fundamental responsibility to design, build, maintain, and operate our gas systems to keep customers and communities safe. The 2022 Gas Safety Plan ("Plan")[1] provides a high-level view of the work we accomplished in 2021 and strives to present important Gas Operations information in a manner that is accessible and clear to a broad audience.

PG&E's 2022 Gas Safety Plan includes aspects that are new since the 2021 Plan. First, the Plan describes PG&E's stand to keep everyone and everything always safe. Section I.3, "PG&E's Goals," outlines PG&E's 2021 Line of Sight goals which align with its eight company goals: Safety, Commitments, Customer, Financial Stability, People, Relentless Execution, Risk-Informed Work and Resource Plan, and Wildfire Mitigation. Section II.2, "PG&E Corporate and Gas Safety Committees," lists several standing committees and reoccurring meetings Gas Operations leadership participate in to govern the safety culture of the Gas Operations organization, including two new enterprise level meetings: the Enterprise Weekly Operating Safety Review and the Weekly Safety Incident Review meeting. Section IV.4, "Records and Information Management," discusses the closure of two Gas Transmission (GT) Order Instituting Investigation (OII) remedies, GT E.05 and GT E.13. Finally, Section VI, "Compliance Framework," introduces PG&E's Gas Organization Controls Program focused on updating and documenting key controls for high and medium risk regulatory requirements.

The Plan also includes updates on items discussed in previous Gas Safety Plans. In Section IV.2.a, "Gas Storage," the Plan states the progress made on the sale of PG&E's Pleasant Creek storage facility as well as reiterates PG&E's decision to retain and operate the Los Medanos storage facility. In Section IV.2.f, "Distribution Mains and Services," PG&E communicates the completion of the Cant-Get-In cross-bore inspections for the San Francisco Region. Finally, in Section VII.1, "Lean Capability Center," PG&E discusses the focus of the Gas Operations Lean Capability Center (LCC). In 2021, the LCC took strides in supporting the organization through their process management journey.

While we have made progress in key safety areas, we realize there is more to do to demonstrate our commitment and progress towards Gas Safety Excellence. 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.

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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 (NG) under pressure through approximately 6,600 miles of transmission pipelines, 43,500 miles of gas distribution pipelines, 4.6 million customer meters, nine compressor stations, and three gas storage facilities. The PG&E NG 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 the public, customers, contractors, and employees safe. PG&E's stance is that everyone and everything is 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 2021. PG&E annually reviews and updates its Plan in accordance with General Order 112-F Section 123.2(k), and Public Utilities Code (Pub. Util. Code) Sections 961 and 963.[1] Figure 1, on the following page, provides a summary of PG&E's performance in key areas.

Gas Safety Improvements

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

GAS ODOR RESPONSE TIMES	2010	2021
Average response time in minutes	33.3	20.6
Percent response within 60 minutes	94.4%	99.5%
SCADA VISIBILITY AND CONTROL POINTS		
Transmission pressures and flows	1,300	2,548
Transmission control points	870	1,001
Distribution pressures and flows	290	4,608
LEAK BACKLOG		
Grade 2 open leak average duration		113 days
DIG-IN REDUCTION		
Third party gas dig-ins per 1000 USA tickets	3.5	0.91

GAS TRANSMISSION	2010	2011-21
Miles of pipeline replaced	9	>278
Miles of pipeline strength tested	0	>1,566
Miles of pipeline made piggable	130	>1,925
Automated valves installed	0	399
GAS DISTRIBUTION		
Miles of main replaced[1]	27	1,185

SINCE 2011 PG&E HAS ALSO

- Completed GPS survey for 100% of the accessible transmission pipeline system using highly precise mapping tools
- Opened a state-of-the-art Gas Control Center in San Ramon, California
- Opened a world-class Gas Safety Academy located in Winters, California
- Opened the Center for Gas Safety and Innovation located in Dublin, California

Independent Third-Party Certifications received for Gas Operations:

2014: PG&E Gas Operations became one of the first utilities to earn two of the highest internationally recognized asset management certifications—the International Organization for Standardization (ISO) 55001:2015–Asset Management System Requirements and Publicly Available Specification (PAS) 55:2008—Specification for the optimized management of physical assets.

2015: PG&E Gas Operations became the first utility in the U.S. to receive certification for compliance with the industry standard for pipeline safety management systems, the American Petroleum Institute Recommended Practice (API RP) 1173:2015— Pipeline Safety Management Systems.

2017: PG&E Gas Operations recertified its safety management system to ISO 55001:2015 and PAS 55:2008

2018: PG&E Gas Operations recertified as compliant with API RP 1173:2015.

2019: PG&E Gas Operations certified as compliant with the intent of American Petroleum Institute Recommended Practice (API RP) 754:2017—Process Safety Performance Indicators in so far as it meets its business operations.

2021: PG&E Gas Operations recertified to PAS 55:2008, ISO 55001:2014 and certified compliance with API 754:2017 and API 1173:2015.

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

[2] Stage 2 recertification audit will be conducted in 2021.

Figure 1 – Gas Safety Improvements

a. STRUCTURE OF THE GAS SAFETY PLAN

The 2022 Plan reports the details associated with the work performed in 2021 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.

- **Gas Safety Excellence Management System (GSEMS):** PG&E's integrated safety management system provides the framework and structure to drive operational excellence and industry-leading safety and reliability performance across the organization.
- **Safety Culture, Process Safety, and Asset Management:** Safety culture, process safety, and asset management together support achievement of Gas Safety Excellence. These sections outline how PG&E manages risk—both the inherent risk of the assets *and* the risk of working on those assets safely. This section describes how the Company identifies risk, prioritizes risks and then works to mitigate them, highlighting the three major categories of gas system risk the Company manages: loss of containment, loss of supply, and inadequate response and recovery.
- **Workforce and Compliance Framework:** These sections review how PG&E qualifies, trains, and engages the workforce to mitigate risk by working on assets safely and performing work correctly. These sections include information about PG&E's workforce training and qualifications programs, and how PG&E achieves compliance.
- **Continuous Improvement (CI):** This section presents PG&E's efforts to continuously improve processes and procedures.

b. Gas Safety Excellence Management System

Gas Safety Excellence is demonstrated by:

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

Figure 2 – PG&E Gas Safety Excellence Management System

The 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 Operations (GO) to establish processes and controls to systematically reduce risk and improve safety. It also required periodic leadership review of processes and programs in GO to drive continual improvement.

The GSEMS is an integrated safety management system that incorporates industry-leading best management practices to support the stance that everyone and everything is always safe. GSEMS provides the framework to systematically manage and maintain operational excellence in asset management, safety culture, and process safety, with a commitment to CI and in compliance with best-in-class industry standards. Certification of compliance to best-in-class industry standards by an independent third-party auditor began in 2014. In 2021, PG&E's GSEMS recertified to the requirements of the following industry standards:

- Publicly Available Specification (PAS) 55/International Organization for Standardization (ISO) 5001-Asset Management System Requirements for Asset Management; and
- American Petroleum Institute (API) RP 1173 Pipeline Safety Management System for Safety Culture.

Additionally, the system was certified as compliant with the requirements of API RP 754 Process Safety Performance Indicators.

System Elements

GSEMS elements establish requirements to address risks inherent to GO 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. GSEMS consists of the following sixteen interrelated elements:

1. Leadership Commitment, Accountability and Employee Participation;

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

c. PG&E's Goals

GO annual strategic goals are developed through the "Line of Sight" process. This process incorporates the Company's focus areas and the updated plans or results from the Enterprise Operating Rhythm process to develop three to five year objectives, annual objectives, and initiatives that are linked. "Line of Sight" goals in 2021 aligned annual objectives with eight company goals: Safety, Commitments, Customer, Financial Stability, People, Relentless Execution, Risk-informed Work & Resource Plan, and Wildfire Mitigation. This planning process results in strategic goals to drive action throughout the business. Related goals and metrics cascade throughout the organization to provide each employee a line of sight to how their actions support PG&E's stance.

d. Public Safety

As mentioned in the introduction and as shown in Figure 1, PG&E continues to make progress and improvements to support the safe operation of the gas system. Three areas of continued focus to drive improvement in public safety are: In-Line Inspections (ILI), Third Party Dig-ins and Gas Emergency Response.

- **ILIs:** In 2021, PG&E increased piggability to roughly 45 percent of the approximately 6,600 miles of the Gas Transmission (GT) system;

- **Third-Party Dig-Ins:** In 2021, PG&E experienced 0.91 third-party dig-ins per 1,000 Underground Service Alert (USA) tickets, outperforming its 2021 target of 1.07 third-party dig-ins per 1,000 tickets; and
- **Gas Emergency Response**: In 2021, PG&E's average response time for immediate response gas odor or gas leak calls was 20.6 minutes, exceeding the target of 20.8 minutes.

e. 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 their concerns and ideas will be heard and followed up on.

In 2021, PG&E developed its 2025 Workforce Safety Strategy, which has been reviewed by senior leadership and the Board of Directors and has driven our execution through the back half of 2021. The 2025 Workforce Safety Strategy includes two major pillars: systems and culture. Systems refers to risk management, equipment, processes, and procedures. Culture refers to employee engagement, adherence to established requirements, sense of urgency for safety, and leadership.

PG&E aspires to eliminate work-place fatalities and reduce the number of serious safety incidents. PG&E established Days Away, Restricted or Transferred (DART) targets for 2021 to achieve a reduction from 2020. In 2021, GO had 92 DART cases at a rate of 1.51. This was a reduction of 34 cases and a rate reduction of 0.65 from 2020. The top three DART nature of injury trends were Sprain/Strain, Musculoskeletal, and Nervous System related. GO completed a Common Cause Evaluation of Sprain/Strain and muscular skeletal disorder (MSD) incidents that occurred in GO in 2020. As a result of the review five corrective actions were identified and closed in 2021 to improve focus on top injury drivers and improve communication and utilization of available preventative resources. Gas employees were involved in 29 Lost Time Injuries, which was a decrease of 11 from 2020. In 2021, the California Occupational Safety and Health Administration (OSHA) recordable rate decreased by approximately 30.1 percent. This is a result of early intervention at the first sign of discomfort, the from PG&E's 24 hour, seven days a week Nurse Care Line (NCL), early reporting, and Industrial Athlete (IA) utilization. In 2021, 75.9 percent of employees who called the NCL reported discomfort or an injury within 24 hours, which was a 0.52 percent increase from 2020. The emphasis on early intervention has had a positive effect on workforce injuries. Based on the review of the data, PG&E believes that encouraging employees to speak to a healthcare professional about an injury or illness within 24 hours contributes greatly to the reduced severity and recovery time of an injury or illness. Through consistent application of timely reporting and preventative efforts, the serious lost time injuries have begun to follow the OSHA recordable curve and shows improvement.

In 2021, GO had four safety incidents that had Serious Injury and Fatality Potential (SIF-P). A SIF review team, composed of department representatives and enterprise safety, evaluates all injuries and near hits for SIF potenital. In August 2020, PG&E adopted Edison Electric International's (EEI) Safety Classification Learning (SCL) Model 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 and classifying 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 GO 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 detemrine if the actions taken were effective in preventing or mitigating the original outcome.

PG&E added additional evaluation measures, 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 2021, GO completed 82 percent of the corrective actions in a timely manner, with a goal of 90 percent. This is an increase of 21 percent from the prior year.

Another area of focus continues to be Motor Vehicle Safety. In 2021, there were 13 Serious Preventable Motor Vehicle Incidents (SPMVI), and no change from 2020. In 2017, the Company installed an in-cab coaching technology to over 2,600 gas vehicles and developed a metric to score employees' driving behaviors. The technology alerts drivers when their vehicle accelerates too fast or brakes too hard. These are both leading indicators to incidents that have the potential to cause extensive damage or a SPMVI. This ratio yields a Safe Driving Rate in which a lower ratio is preferred. In 2020, GO scored a Safe Driving Rate of 4.6. In 2021, GO finished with a Safe Driving Rate of 4.4, a 4.3 percent reduction from the previous year. 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, DART rate, and motor vehicle incidents.

f. 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 Corrective Action Program (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 2025 Workforce Safety Strategy. As a token of appreciation, the employees who nominate them are also eligible to receive rewards and recognition. In 2021, most employees continued to find ways to recognize each other through the program even with the change for some employees performing remote work. The program continues to mature and in 2021, 141 Caught Being Safe nominations were submitted recognizing office and field-based employees.
- **Process Safety Champion Award** – This award recognizes teams and individuals for going above and beyond in applying the keys to Process Safety to their work, such as having a questioning attitude, taking time to evaluate the hazards prior to starting a task, and reporting a CAP.

g. NATURAL GAS LEAK ABATEMENT COMPLIANCE PLAN

On January 22, 2015, the California Public Utilities Commission (CPUC or Commission) opened Order Instituting Rulemaking (OIR) Rulemaking (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 NG leakage from Commission-regulated NG 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 greenhouse gas (GHG) emissions. In the June 16, 2017 Phase 1 Leak Abatement OIR Decision (D.) 17-06-015, the Commission adopted 26 Best Practices related to NG leak abatement. PG&E's gas leak abatement program includes annual methane emission tracking reporting, and a biennial best practice compliance plan submission. Attachment 2 to this plan is the third biennial Leak Abatement Compliance Plan prepared in accordance with the Commission's decision.

PG&E has made strides in reducing the methane emissions of its systems through the execution of its first two 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; 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.

The 2022-2023 Compliance Plan will add new leak abatement initiatives to meet the 2025 goal of 20 percent reduction compared to the 2015 baseline and towards 40 percent reduction by 2030.

II. Safety Culture

PG&E's commitment to strengthening our safety culture and performance is reinforced by our stands (Figure 3) that "Everyone and Everything is Always Safe." GO Safety and Leadership worked to improve workforce safety through building a culture focused on the hearts and minds of our employees and building a deeper partnership between GO leadership, Grassroots Safety Teams and the Labor Unions. The goals of the partnership were to focus on preventing and reducing employee injuries, promoting healing and return to work; and ensuring quality and appropriate medical care for our employees. In 2021, with leadership support, GO continued its focus on preventing and reducing employee injuries, promoting healing and return to work, and ensuring quality and appropriate medical care for our employees.

OUR STANDS:
WHAT we will deliver

PEOPLE
Everyone and everything is always safe.
Catastrophic wildfires shall stop.
It is enjoyable to work with and for PG&E.

PLANET
A healthy environment and carbon-neutral energy system shall be the reality for all Californians.

PROSPERITY
Our work shall create prosperity for all customers and investors.

Figure 3 - PG&E Stances

With the ongoing impact of the coronavirus (COVID-19) as a risk to our workforce and customers, GO continued to adjust and implement COVID-19 protocols as local, state and federal guidance changed. As office employees continued to work in a remote environment, GO in conjunction with PG&E's EH&S employees were equipped with the necessary ergonomic equipment and provided virtual ergonomic assessments to reduce the potential for ergonomic related injuries. Field employees adapted to ever changing COVID-19 guidelines and identified best practices to ensure the health and safety of their fellow employees and our customers. In addition to the COVID-19 measures, the GO leveraged insights from the Gas Safety Oversight Council through its CI journey.

The organization continued to build upon the prior years benchmark learnings and improved upon the Gas Safety Council charter to include active participation and updates from Grassroots members and International Brotherhood of Electrical Workers (IBEW) partners within the Control the Pressure Team. The Gas Safety Council effectively identified action items and facilitated closure through the charter guidelines. The Grassroots Rally room continued to expand to a broader group of key participants to improve collaboration and resolution of identified safety concerns. There was also an increase in problem solving sessions to identify improvements in communications and leader engagement.

GO continued to champion IA utilization for frontline employees and provide leaders with the necessary injury data to aid in implementation of injury prevention measures. GO and EH&S utilized IA engagement in work yards that were identified as having higher risks and exposures. The IAs focused on observing employee biomechanics, ergonomics and risk behaviors resulting in identification of corrective actions and recommendations. This was additionally complemented by Field Safety Observations focused on field employee ergonomics. Field Safety Specialists identified over 1,030 Safe and At-Risk Findings, mitigating over 270 At-Risk Findings in 2021.

Virtual Ergonomic Assessments for Remote Workstations. In alignment with the enterprise requirement for office based employees to complete preventative virtual ergonomic evaluations, 1,753 GO employees completed virtual ergonomic assessments. This was a 98 percent response rate of the 1,784 evaluations requested. Gas Safety's 2021 focus provided GO with the awareness and tools to be successful beyond this initiative. 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. GO will continue to utilize 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 influence unsafe behaviors to change by connecting with those that do the work, build/improve our Safety Culture through focusing on the hearts and minds of our employees, and continue to build a deeper partnership between Gas and Labor Unions to drive safety.

a. EMPLOYEE ENGAGEMENT

PG&E continues to reinforce the various initiatives to enhance employee engagement. These initiatives included: Lean Management (Lean), Safety Leadership Development, and Leader in the Field.

Lean Management. GO continues to support and reinforce the importance of "Operating Reviews" throughout the organization. Operating Reviews are quick, structured conversations among team members that occur daily, weekly and monthly. Operating reviews provide a platform for employees to review visual management and understand the status of performance, prioritize opportunities, drive actions, and confirm effective countermeasures. In addition, adequate resources are provided (i.e., people, time, and leadership support) for team members to conduct scheduled Problem-Solving sessions where roadblocks are identified, and employees are given the opportunity to help develop solutions.

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

Safety Leadership Development. Beginning in 2017, the *Leading Forward: Safety Leadership* program was delivered to all operational leaders. The program included three workshops: Shaping a Safety Culture; Identifying and Controlling Exposure; and You Are Not Alone. In 2021, leaders continued to sustain the program by having periodic discussions in which best practices, lessons learned and collaboration for solving issues occurred. A total of 91 GO leaders (49 Crew Leads, 42 Supervisors and Superintendents) completed the program in 2021.

Leader in the Field. Since March 2020, Leader in the Field continues with a focus on the supervisors and managers being in the field with their employees to assist in removing barriers and resolving safety concerns. Across all PG&E Gas Operation supervisors, time in the field averaged approximately 50 percent throughout the year in 2021. This means nearly 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 25 percent throughout the year in 2021.

i. CORRECTIVE ACTION PROGRAM

The CAP is an integral part of our safety culture in GO. PG&E's continued use and support of the CAP demonstrates to coworkers, contractors, regulators, and customers, that we have an 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 GO from a reactive approach of solving issues, to a proactive analysis that helps prevent issues before they result in an incident. The CAP provides real-time data and ensures transparency and accountability. The system is designed to provide trending capabilities and a CI 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 operation specialists and cause evaluators. The operation 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 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 to be entered into CAP for resolution and tracking. There are a few issues that may fall outside the scope of CAP (e.g., Information Technology (IT), Compliance and Ethics, facility requests); however, we do not discourage their entry, but will transfer the CAP notification to the most appropriate tool/program for follow up.

How the Gas CAP Process Works

Initiation: The initiator, who can be any PG&E employee (or contractor with network access), can submit any issue or process improvement idea into the CAP. They have several ways to submit an issue such as through the CAP website, the mobile CAP App, calling the CAP helpline, submitting a paper form, via Systems Applications and Products (SAP), or by e-mailing the CAP help desk. Once the CAP is in submitted status in GO, the Gas CAP team will process it for assignment. On average, Gas employees submit 30 CAP notifications each day.

Assignment and Resolution: The CAP process employs a standardized approach (Figure 4) to reviewing and assigning CAP notifications. 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 owner.

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.

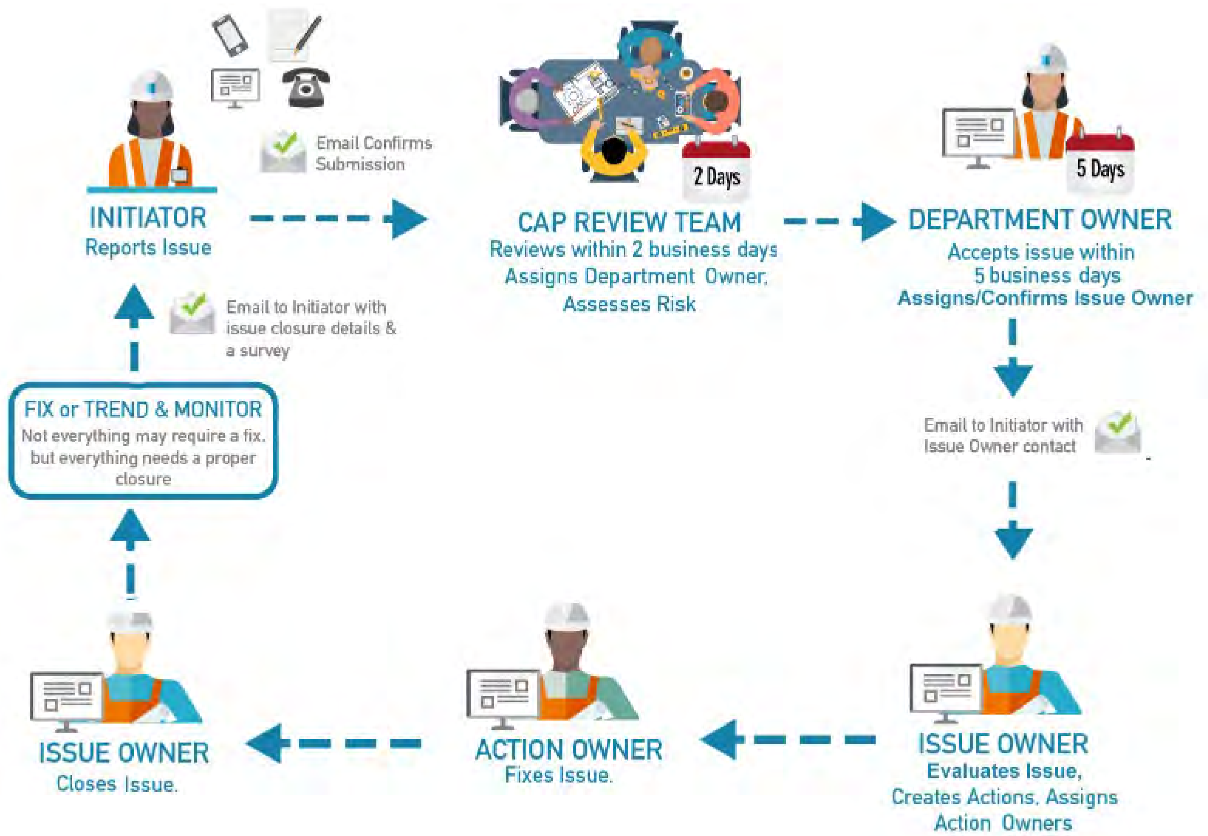

Figure 4 – CAP Process

How Notifications are Risk Ranked

Risk matrices are used to rate and compare risk of hazardous events by considering the likelihood and consequence of an event happening, to increase visibility and help with decision making on 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:

Probability of Event Occurrence x Severity of Consequence = CAP Notification Risk

- **Probability of Event Occurrence**: The extent to which an incident, event, or condition has occurred or recurred (frequency).
- **Severity of Consequence**: The result of an incident, event, or condition by considering the degree[3] the public, employee(s), or property was in jeopardy of harm or loss (severity). This includes an assessment of the risk associated to safety, asset damage, reliability, financial impact, compliance, environmental, and reputation.

The CAP notification risk level is used to determine the appropriate evaluation type that will be assigned and provides GO 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 CI processes. There are four types of cause evaluations:

- **Root Cause Evaluation (RCE):** 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).
- **Apparent Cause Evaluation (ACE):** 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.
- **Work Group Evaluation (WGE):** 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.
- **Common Cause Evaluation (CCE):** 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. CCE can only be conducted 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.

Gas Event Classification Matrix						
UNITENDED 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[3] • 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[2] • 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[3] • 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[2] • 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 = Small and large overpressure events are defined by FIMP.

3 = 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.

Figure 5 - Event Classification Matrix

In 2021, an Event Classification Matrix (ECM) was developed to provide formal guidance and consistency to determine the appropriate level of cause evaluation.

A cause evaluation can be related to a wide range of topics in GO, 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 formal (documented) WGEs are required for non-conformances and high-risk quality findings. Gas completed 212 formal WGEs in 2021. Figure 6 shows the total number of evaluations completed in 2021.

RCE	ACE	WGE	CCE
1	43	11,527	4

Figure 6 – Cause Evaluations Completed in 2021

How CAP Success is Measured

In 2021, GO' goal was to engage at least 33 percent of its workforce to use CAP, and at year-end it had engaged 38 percent. In 2021, GO employees submitted 10,867 notifications—averaging just over 905 per month—and closed 11,652 notifications.

To ensure accountability and transparency, leaders receive an Executive CAP Dashboard Report (Figure 7) each week that details how their organization is performing on their CAP items. Key performance indicators reported in 2021 include:

- Percent of Unique Initiators – This is the number of employee submissions divided by the total count of employees. The 2021 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 2021 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 2021 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 2021 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 2021 goal for average age of open high-risk notifications was 180 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 2021 goal for average age of open medium-risk notifications was less than or equal to 180 days.

Figure 7 shows how GO performed against the above-mentioned key performance indicators in 2021.

Figure 7 – CAP Metrics

CI and Speak Up Culture

The Gas CAP process continues to mature and serves an important role in GO 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 GO that all of PG&E's line of business (LOB) adopted the Gas model when CAP was deployed company-wide. In 2021, the CAP Department logged 62 Eagle Eye nominations, which included nominations for identifying and submitting "good catch" issues and for efforts in resolving those issues. In 2021, twelve Eagle Eye winners were awarded (both individual contributors and teams) for bringing light to issues in GO which included, but were not limited to, cybersecurity concerns, streamlining document review and approval process, improved ergonomics for lifting heavy materials, and strengthening engineering design process and communication.

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 (PT) process. The PT process complements the cognitive trend process by creating a formalized systematic statistical approach. The CAP team performs monthly 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 GO.

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 PTs in 2021 and provided analysis and recommendations to the respective functional team in GO.

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 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.

ii. 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 fostering a workplace where everyone feels safe to ask for guidance, share ideas or raise concerns—and one where everyone is confident that those concerns will be heard and taken seriously.

In addition to the E&C Helpline, PG&E's Federal Court-Appointed Monitor[4] maintained a dedicated hotline, e-mail address, and website to which employees and the public can submit concerns. Although the hotline is not equipped to handle safety emergencies or other issues requiring immediate attention, it served as another resource for employees to raise issues or concerns.

iii. 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 2021, the average of gas incoming MPR's had an average cycle time of 14 days, with a target of 20 days.

Field MPRs tend to be more complex, and as a result, may require more time to resolve. They require collecting the part from the field, shipping it to engineering, performing an investigation and interviews on method of installation, and material testing in a test lab to validate the method of failure. After the conditions and method of failure are determined, the material may be sent back to the manufacturer if it is proven to be defective. In 2021, Field MPR resolution had a 182-day average cycle as compared to its target of 70 days. To improve the resolution times and quality, MPR closures will be risk rank driven, and an MPR closure target will be added to the evaluators' safety metrics.

b. PG&E Corporate and Gas Safety Committees

PG&E's safety governance structure drives a consistent safety culture and aligns to PG&E's safety strategy and results. Table 1 describes PG&E's Corporate and GO safety committees and meetings. GO utilizes the forums in Table 1 to ensure alignment with the Chief Risk Officer/Chief Safety Officer across the enterprise.

Table 1 – 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 and employee safety), and compliance issues related to PG&E's nuclear, generation, gas and electric transmission, and gas and electric distribution operations and facilities ("Operations and Facilities"), (ii) significant operational performance and other compliance issues related to such Operations and Facilities, and (iii) risk management policies and practices related to such Operations and Facilities.
Safety Technical Council	Orchestrate PG&E's efforts in managing workforce safety risk in a coordinated, proactive, effective, and efficient manner. The objectives include: Tactical problem solving; Coordination across business areas on the implementation of tools, fixes, solutions; Contribute to a strategic approach and roadmap for workforce safety by incubating ideas and reviewing draft projects before they go for approval; Inform software needs and technology projects when needed; and Follow a risk-based approach to assess major adaptation needs, if any.
Gas Safety Council	Sponsors initiatives to improve line of business (LOB) safety. Monitors LOB's safety performance and initiatives so that safety initiatives adequately address risks.
Gas Grassroots Safety Teams	Employee-led efforts to identify opportunities to improve safety, define and validate possible solutions, and implement and promote safety initiatives.
Enterprise Weekly Operating Safety Review	Weekly safety performance for the enterprise is reviewed weekly to protect the monthly performance. Trends, 30/60/90 day safety plans, and catch-back plans are discussed for each LOB, including GO.
Weekly Safety Incident Review Meeting	Individual incidents from each LOB are reviewed to share containment actions, lessons learned, and countermeasures.

i. Gas Safety Council

The Gas Safety Council meets on a monthly basis and is 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 GO, SVP of GO, Engineering, Vice President (VP) of Gas Transmission and Distribution (GT&D), and the Senior Director of Safety, Quality and Contract Management. Invited attendees include the Labor Union Leaders from the IBEW Local 1245 and ESC, Grassroots Safety Teams,[5] the Federal Monitor representatives, Gas Safety, Corporate Safety and other key stakeholders as needed. The primary objective is to provide overall governance of safety, guide department safety strategy, ensure compliance with Company safety standards, execute Chairman's Risk and Safety Committee directives, provide another channel to raise safety concerns and promote positive safety culture change. In 2021, the Gas Safety Council charter was modified to include IBEW and ESC leaders as Committee members for continued partnership and collaboration.

ii. Gas Grassroots Safety Teams

Gas Grassroots Safety Teams are composed of Chairs, Co-Chairs and members primarily from Gas Operations and Engineering field positions. Chairs meet on a regular cadence to discuss issues, strategy, concerns, successes, roadblocks and any barriers that may exist. As of December 2021 Grassroots had over 242 members.

In 2021, the Grassroots Rally Room further expanded its participants through inclusion of organizational leaders both within GO and within Shared Services. This expansion helped streamline issue elevation and resolution. It additionally improved upon the organizations cohesive approach to safety strategy.

Throughout 2021, the Gas Grassroots Safety team published monthly newsletters highlighting safety activities throughout the LOB. Newsletters include input from several teams within GO, including Maintenance and Construction, Damage Prevention, GrassrootsTV, Gas Pipeline Operations and Maintenance, Field Services, Corrosion, Leak Survey, Office, IBEW Local 1245, and Ergonomics. A few highlights from the 2021 newsletters include:

1. May 2021 Issue – Working Safely From Home Handbook;
2. September 2021 Issue – Wildfire Smoke Protection Program Leader Toolkit; and
3. October 2021 Issue – Using the Right Tools for the Job.

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 is used for engineering new facilities, modifying existing facilities, maintaining equipment, and ensuring safe operation.

The Process Safety Management System consists of four foundational areas (Figure 8): Commit to Process Safety, Understand Hazards and Risk, Manage Risk, and Learn from Experience. PG&E is improving process safety performance by strengthening performance in each of these areas. Process Safety Management System is well integrated within the GSEMS, [see Section I.2 *Gas Safety Excellence Management System*] to safely manage the planning, construction, operation, decommissioning and

Figure 8 – The PG&E Process Safety Management System

maintenance of gas assets and associated activities and ensure the safe, reliable, affordable and clean delivery of NG.

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

Process Safety Highlights from 2021 include:

Commit to Process Safety. Guided by the elements set by the Center for Chemical Process Safety, PG&E's commitment to implement process safety aligns with API Recommended Practice (RP) 754 *Process Safety Performance Indicators for the Refining and Petrochemical Industries*.[7] A risk-sorting criterion to track and trend process safety leading and lagging indicators is used to identify emerging issues before incidents occur.

The Process Safety team continued to review changes to existing procedures and standards and new procedures and standards in order to help GO operate and maintain safe facilities and consistently implement process safety practices.

Understand Hazards and Risk. Process Safety Management is a key component in reducing PG&E's Operational Risk Exposure. In 2021, PG&E used process safety principles in its large OP event reduction initiative [see Section IV.5.l. *Mitigating the Risk of Loss of Containment: Overpressure Elimination Initiative*]. The Process Safety team continued to support the investigations of large OP events. The team also 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.

Manage Risk. Process Safety efforts support risk mitigation. In 2021, risk mitigation continued through Management of Change (MOC) (Figure 9) process improvements. The Process Safety team continued working with stakeholders to close the identified gaps as identified in the MOC effectiveness review and gap analysis conducted in 2019. At the end of 2021, all of the MOC effectiveness review recommendations were completed. The focus of the MOC program is to assure that changes in operations, procedures, standards, facilities, materials, or organizations are evaluated to identify hazards and ensure associated risks are effectively managed. MOC ensures the changes achieve their intended purpose without compromising workforce, public, and environmental safety. This systematic approach helps to maintain the continued safety of the workforce throughout the process. In addition, MOC ambassadors and stakeholders have been engaged in the MOC Community of Practice, first launched in 2019. This endeavor serves as a platform to engage and communicate best MOC best practices and lessons learned among diverse GO teams. Additional accomplishments in 2021 to promote MOC training, awareness and communication included the development and publishing of three MOC videos produced by Grassroots Safety, publication of the quarterly MOC newsletters, and MOC awareness survey.

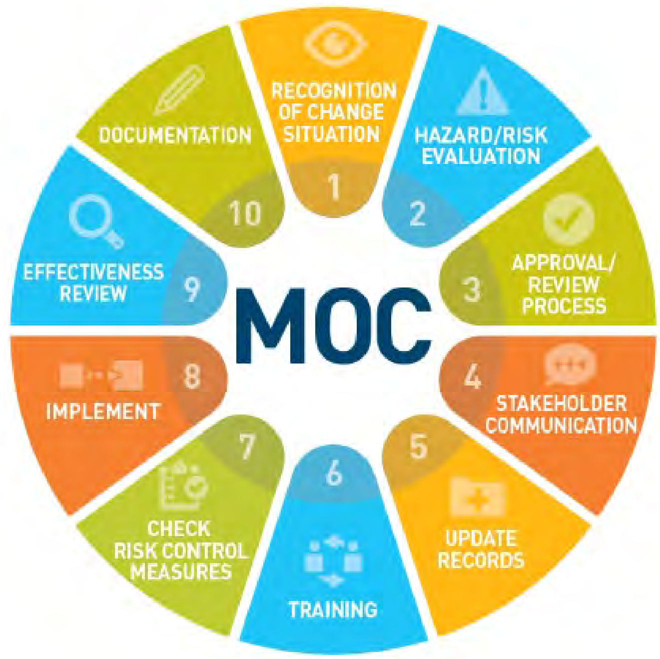

Figure 9 – Gas Operations MOC Process

The Process Safety team also continued to update the Pre-Startup Safety Reviews (PSSR) and PHA checklists. The Process Safety team revised the Process Safety Management training and expanded the list of profiled employees to reach a larger population within GO.

Learn from Experience. PG&E strives to continuously improve in process safety. Process Safety engineers support investigations and cause evaluations related to overpressure events, as described under the Understand Hazards and Risk section above and as part of the CAP process. Cause evaluations are conducted to identify the cause of an incident, the issue, or why an error or failure occurred, to implement recommendations or safeguards that will reduce the risk (severity and/or probability) of recurrence and to apply CI. In addition, lessons learned from incidents are shared through Process Safety Moments. Process Safety Moments are a standing agenda item within GOs' monthly Risk and Compliance Committee (RCC) meetings. Cross functional teams are assigned to present Process Safety Moments during these RCC meetings.

In 2021, GO continued the journey of Process Safety Management maturity. GO continued to be compliant, per a third-party assessment, with the intent of API RP 754, Process Safety Performance Indicators, demonstrating a commitment to incident prevention. The Process Safety Indicator (PSI) dashboard, based on a pyramid framework where the most leading indicators are at the bottom of the pyramid (Figure 10), has been reviewed monthly with Mega Process Owners (POs) and presented monthly at Operational Review Meetings, Quality and Process Improvement Committee or/and other senior leadership platforms. Aligning metric owners by Mega Process strives to drive ownership and accountability and ensure leading indicators (Tier C and D) are 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. Metrics are evaluated continuously during the Daily Operating Reviews or huddles and calibrated at the beginning of the year to ensure that GO drive the right CI conversations.

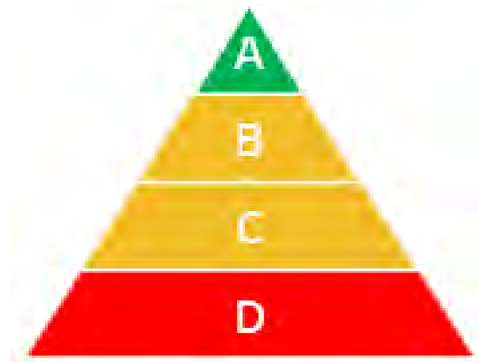

Figure 10 – Pyramid Framework for PSI Dashboard

IV. ASSET MANAGEMENT

PG&E builds, operates, and maintains NG infrastructure to transport, store, and deliver gas to customers over Northern and Central California. There are risks inherent to operating any NG system; this is particularly true for PG&E's system which passes through populated areas and a wide variety of terrain. The top three operational risks confronting PG&E's NG system are the Loss of Containment on GT Pipeline, Loss of Containment on Gas Distribution Main or Service, and Large Overpressurization 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 GO manages risk, and the current risk portfolio.

a. 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]

b. ASSET FAMILY STRUCTURE

Since assets can face different types of risk, PG&E developed an asset family structure to recognize and manage these differences, yet drive consistency in the way PG&E thinks about and addresses risks. PG&E identified nine asset families within GO which are illustrated in Figure 11.

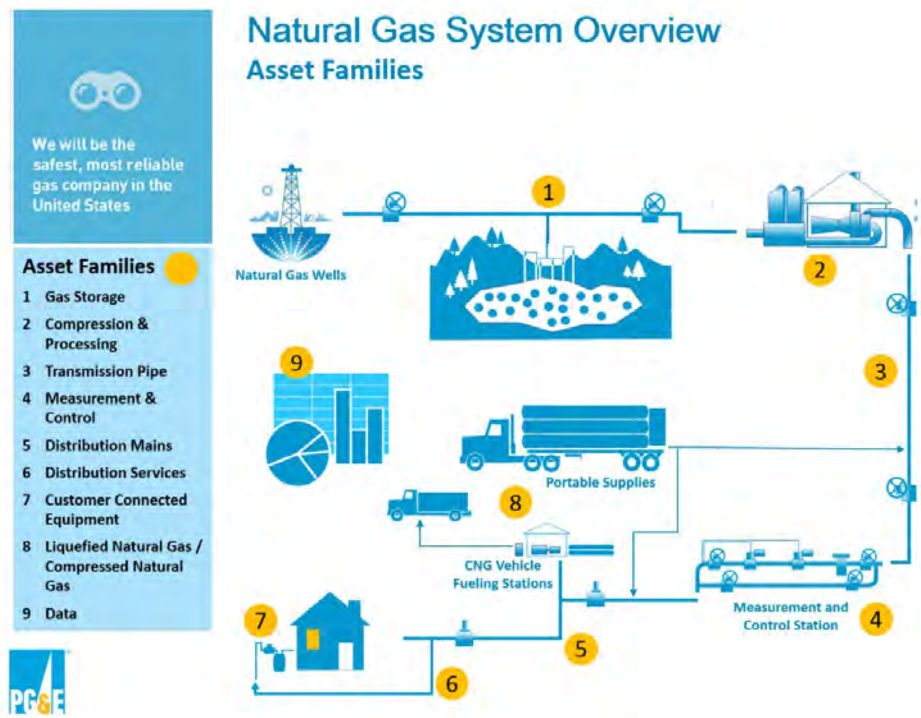

Figure 11 – Natural Gas System Overview – Asset Families

Each asset family has an Asset Family Owner who is responsible for knowing the asset condition and the risks to the assets, and developing a risk-informed Asset Management Plan, which is a five plus year plan for managing gas assets. For 2021 changes to PG&E's Asset Management Plans, please see Attachment 3.

The Asset Family Owner leads the preparation of the Asset Management Plan for each asset family that describes:

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

These Asset Management Plans 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 progress towards achieving strategic objectives.

i. Gas Storage

Figure 12 – Rig and Well Platform

Presently, the Gas Storage Asset Family includes PG&E's owned and operated underground NG storage facilities at McDonald Island, Los Medanos (LM), and Pleasant Creek (PC). The primary assets within this family include 108 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.

However, demand forecasts are expected to decline as California works to meet its GHG emissions goals and new regulations that have initiated major changes to the requirements around design, risk and integrity management (IM), and operations and maintenance for wells and reservoirs impact our current asset structure and reliability model. Moreover, regulations related to gas storage continue to promulgated in accordance with legislative proceedings and are expected to continue to increase and evolve in the coming years.

The United States (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 IM, design standards, emergency response, and training. Likewise, the California Geologic Energy Management Division (CalGEM, formerly known as the Division of Oil, Gas, and Geothermal Resources, DOGGR) introduced final regulations effective in October of 2018 requiring modifications to the 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.

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 PC (2 Bcf working gas) and LM (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 PC storage field; PG&E is currently engaged in the sale process with an interested party for the sale of the PC Facility and plans to submit an 851 filing to the CPUC in 2022. Further, on June 30, 2021, PG&E filed the 2023 GRC that included the decision to retain LM and continue to operate the facility as storage.

In response to the recently introduced PHMSA and CalGEM regulations, PG&E's Gas Storage Asset Family completed an evaluation of both PHMSA's and CalGEM's final regulations, amended its Well Risk and IM Plan, and in March 2019 filed a seven-year plan for review and approval by CalGEM to meet the deadlines established by the regulations to periodically inspect wells and retrofit all of its storage wells to tubing and packer by 2025. In December 2020, PG&E received correspondence from CalGEM indicating the proposed testing schedule coupled with conversion was not satisfactory and a revised testing schedule was required to be submitted to CalGEM in January 2021. This plan is pending CalGEM review and approval. On June 15, 2021, CalGEM accepted the modified plan conditionally to complete baseline inspections in accordance with CCR, title 14, Section 1726, provided additional measures be implemented including: (1) annual thru-tubing well inspections and (2) 24-month pressure testing following a well's conversion to dual barrier; and (3) monthly reporting of progress and schedule of well inspection activity. CalGEM has not made a decision regarding the proposed reinspection frequency and this item remains outstanding.

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

Table 2 – Gas Storage Asset Management Plan Strategic Objectives and Progress To-Date	
Overall Objective/Goal	**Progress Towards Goal**
Complete baseline well production casing assessments on 109* wells by 2025	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
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
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 1.6miles 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.
Continue PHA and Pre Start-up Safety Review (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 PSSR 2021: 36 PHAs, 14 PSSRs

* 8 Wells Plugged & Abandoned from 2017-2020, for a net remaining wells of 109.

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

ii. 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 free from particulates and is sufficiently dehydrated and odorized so that it can be transported to the GT&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. Major assets include 40 company-owned compressor units, as well as associated equipment such as filter-separators, pumps, motor control centers, station piping, among others. Additionally, this asset family includes 7 gas odorizer units. Together, these stations support the system's reliability and the odor added to gas helps keep PG&E customers safe when gas arrives at their service point.

Figure 13 – 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 3 – Compression and Processing Asset Management Plan Strategic Objectives and Progress To-Date

Overall Objective/Goal	Progress Towards Goal
Codify the Facility IM Program in published guidance document and utilize by end of 2021.	• Standard TD-4880S, *Facility Integrity Management Program*, published in 2021.
Maintain total number of compressor unscheduled outages at current target in 2021.	• Number of unscheduled shutdowns (including rental units) well below do-not-exceed target in 2021. Target = 224; Actual = 179.
Complete all ECA1 activities by end of 2022 and complete 50% of ECA2 mileage by 2028.	• ECA1: Completed 95% (feature basis) of SFL handoffs for upload to GT Geographic Information System (GT-GIS). Completed coordination of remediation work MAOP validation flags at 22 stations. • ECA2: Completed field inspections at nine facilities and submitted three stations for internal review and approval;.
Complete Critical Documents defined by TD-4551S for all facilities by 2022.	• 2021 Production: 85 facilities submitted; cumulative target 89; 329 total facilities complete.

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

iii. Transmission Pipe

The Transmission Pipe asset family consists of approximately 6,600 miles of line pipe and major components, such as valves and fittings, used in transporting NG.[12] 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. TIMP is a core foundation of PG&E's ongoing efforts to provide safe and reliable service, consistent with industry best practices, and based on the federal TIMP regulations.[13] The Transmission Pipe Asset Management Plan describes the roadmap for mitigating and managing risk for this asset family and achieving the established asset management objectives. The plan's objectives include the following:

Figure 14 – Line 215-1 installing 24" pipe at Patterson

Table 4 – Transmission Pipe Asset Management Plan Strategic Objectives and Progress To-Date	
Overall Objective/Goal	**Progress Towards Goal**
Apply IM principles to transmission pipelines covering 100 percent of population living along transmission pipelines by 2036	• 91 percent of population living within Potential Impact Radius covered by IM principles. • Upgraded 145 miles for ILI inspection capability • 45.1 percent of system is now piggable • See Section IV.5.g for additional information on ILI. • Improved ANAGRAM project risk analysis tool to visualize risk profiles for the pipeline system • Created a wildfire response procedure specific to transmission pipe assets • Prepared the cathodic protection (CP) system to transition to a polarized potential (-850 off) criterion on all transmission pipe
Meet 100 percent of system capacity obligations and eliminate high risk manual operations in peak day conditions by 2021	• High risk manual operations decreased from 12 in the 20-21 winter to 8 for the 2021-22 winter. • 5 of 9 transmission regions meet all expected load conditions. • See Section IV.6.a for more information on System Capacity Design Criteria
Update PG&E's GT assets and technology to improve recognition and response to significant transmission events by 2030	• See Section IV.7.a for additional information on system visibility progress. • Installed 18 automated valves in 2021. • Installed 4 local transmission Supervisory Control and Data Acquisition (SCADA) sites.
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. • See Section IV.5.b for more information on Line Marker progress.

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

iv. Measurement and Control

PG&E's Measurement and Control (M&C) assets monitor, measure, and control pressure and flow within the GT&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 15 – M&C Complex Station-Above Ground

The physical assets within this family include three gas terminals, 375 GT stations (both simple and complex), 457 large volume customer type assets, 93 automated valve sites, 2,360 distribution district regulator stations, 1,722 farm taps, 86 gas quality analyzers, and 126 odorizers. PG&E's M&C equipment is located above and below ground, as well as within vaults and buildings. Examples of M&C complex and large volume transmission stations are shown in Figure 15 and Figure 16.

Figure 16 – Large Volume Customer Transmission Station

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 5 – M&C Asset Management Plan Strategic Objectives and Progress To-Date

Overall Objective/Goal	Progress Towards Goal
Codify the Facility IM Program in published guidance document and utilize by end of 2021.	• Standard TD-4880S, *Facility Integrity Management Program*, published in 2021.
Mitigate overpressure risk due to common failure mode at 50% of H-14 facilities by end of 2022.	• Large OP events per year: 2015 – 7; 2016 – 10; 2017 – 11; 2018 – 5; 2019 – 11; 2020 – 9: 2021 – 5. • Continued installation of secondary OP protection devices. Over 40 percent of H-14 (pilot-operated) facilities currently have devices installed.
Complete all ECA1 activities by end of 2022 and complete 50% of ECA2 mileage by 2028.	• ECA1: Completed 95% (feature basis) of SFL handoffs for upload to GT-GIS. Completed coordination of remediation work for MAOP validation flags at 22 stations. • ECA2: Completed field inspections at nine facilities and submitted three stations for internal review and approval;.
Complete Critical Documents defined by TD-4551S for all facilities by 2022.	• 2021 Production: 85 facilities submitted out of a target of 89; 329 total facilities complete.

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

v. DISTRIBUTION MAINS AND SERVICES

Figure 17 – Employee Working on Distribution Service

This asset family includes approximately 43,500 miles of pipeline that connects to the gas M&C asset family on the upstream side and transports NG to customers throughout the service area. It also includes over 3.6 million service lines that deliver gas from the distribution mains to the assets in the Customer Connected Equipment family on the downstream side. The DMS asset family begins at the outlet of the M&C 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 of Distribution Mains and Services assets. PG&E continues to identify and assess threats to Distribution Mains and Services assets and works to mitigate those threats, including through its Distribution Integrity Management Program (DIMP). Some key strategic objectives include the following:

Table 6 – Key Distribution Mains and Services Metrics

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 1.07 dig-ins per 1,000 tickets for 2021. In 2021, PG&E experienced 0.91 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	2013: 69 miles replaced 2014: 66 miles replaced 2015: 102 miles replaced 2016: 120 miles replaced 2017: 145 miles replaced(exceeded the target of 130 miles) 2018: 165 miles replaced (exceeded target of 163 miles) 2019: 126 miles replaced (exceeded target of 125 miles) 2020: 131 miles replaced (exceeded COVID adjusted target of 125.6 miles) 2021: 191 miles replaced (exceed target of 189 miles)
Finalize legacy cross bore inspection scope by 2025 and re-establish the inspection timeline	PG&E has finalized the scope of work for San Francisco inspections. Work is on-going for scope of work finalization for non-San Francisco inspections.

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

vi. Customer Connected Equipment

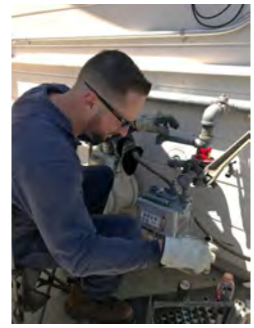

Figure 18 – PG&E Employee Working on Customer Connected Equipment (Photo Captured Pre COVID-19)

The Customer Connected Equipment Asset Family is composed of approximately 4.6 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 7:

Table 7 – 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
Identify and remove problematic regulators by 2022	Over 1,700 replaced in 2015 Over 1,488 replaced in 2016 Over 800 replaced in 2017 Over 1,600 replaced in 2018 Over 1,600 replaced in 2019 Over 300 replaced in 2020 Over 700 replaced in 2021

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

vii. Liquefied Natural Gas and Compressed Natural Gas

The Liquefied Natural Gas (LNG)/Compressed Natural Gas (CNG) asset family consists of portable assets that provide NG 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 also the inclusion of PG&E owned portable cross compression which is primarily utilized to move isolated methane to an adjacent pipeline reducing overall raw methane emissions during pipeline work. In 2021, there were no loss of containment incidents for portable assets [see Table 8].

Figure 19 - 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 NG 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 2021, remained 100 percent compliant where PG&E's NG vehicle fueling customers authorized to fill at our stations either -submitted their required three year vehicle certificates of inspection or had their fueling privileges suspended until this inspection was completed. In 2021, there were no significant loss of containment incidents for CNG Station assets.

Figure 20 – A Large-scale LNG Injection Site

Table 8 – 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	2021 Activities: Continued maintenance of LNG/CNG equipment and assets. LNG/CNG equipment training development including adoption of LNG/CNG;s apprenticeship program and operation. Continued Improvements in quality control (QC) program to verify overall effectiveness of maintenance and training programs.
Implementing an industry-leading inspection program to improve safety inspection certifications to 100 percent of CNG fuel customer vehicles	2021: 100 percent of NG fueling customers authorized to fill at our facilities have submitted their three year cylinder certification.
Reduce risk of portable NG transportation traffic incidents by reducing equipment issues through an improved maintenance program	2021: Continued maintenance of LNG/CNG portable over-the-road assets by dedicated fleet mechanics with Transportation Services QC program in place to verify overall effectiveness of below the deck maintenance program.

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

viii. DATA

In 2018, PG&E GO determined that creating an asset family specifically for data is consistent with industry best practice and will provide the appropriate attention and resources to the essential data sets required for the safe and efficient operation of PG&E's gas business. Data should be properly managed to have an appropriate life cycle, generation and disposal considerations, and QC check points.

In 2020, PG&E established an Enterprise Data Management (EDM) organization and in 2021, a nation-wide search culminated in the hiring of a new VP, Chief Data and Analytics officer, reporting to the Executive VP of Engineering, Planning and Strategy. EDM is responsible 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 GO business units. Such centralization of the data management function ensures alignment of data strategies with the enterprise 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 50+ largely Electric-focused source systems, which contain billions of records relevant to asset health analytics such as Geographic Information System (GIS) and SAP. The number of connected systems, records, and enabled analytics models will continue to grow as additional data products are developed. 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, support for data management and advanced analytics.

Strategic goals, and progress towards those goals are listed in Table 9, below:

Table 9 – Data Asset Management Plan Strategic Objectives and Progress to Date	
Overall Objective/Goal	**Progress Towards Goal**
1. Implement Data Stewardship consistent with Enterprise Data Strategy	1. Mapped GO Knowledge Portal processes to all data sets in data asset register. 2. Identified the top 20% of risks related to identified data events. 3. Identified individual stewards for TIMP and DIMP data assets 4. Defined locations of TIMP and DIMP data. 5. Working with TIMP and DIMP stewards to identify pertinent metadata including the quality and condition of 178 data sets.
2. Propose a framework to assess risk for GO data by end of 2021.	1. Qualitative model developed for risk-based prioritization and used to develop data quality work plans. 2. Framework to tie data to risk-drivers identified and in use.
3. Develop KPIs that reflect risk improvement in key areas	**KPIs:** 1. Number of data sets mapped to driver of risk 2. Number of data sets with a defined threshold of data quality/Number of data sets that meet that threshold of data quality 3. Number of data sets with defined period of useful life/Number of data sets within useful life thresholds
4. Develop 5-year vision around risk assessment.	1. AFO Interviews to understand LOB needs 2. Identified process for associating data to risk 3. Identified the top 20% of risks related to identified data events 4. Hired full staff for Data team
5. Develop data governance document including clearly defined data owners, stewards, and systems of record.	• Published by EDMP team with support from Gas Ops data team, last updated in April 2021.

6. 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.	1. Received $3M from the Work Finance Review committee for 2021 Data Clean up work
	2. 6 projects selected/Bundled into 4 work categories
	  1. SCADA Clean up: 100% complete
	  2. Farm Taps: 90% complete
	  3. SAP/GTGIS Misalignment reconciliation: 2021 scope 88% complete
	  4. SAP/GDGIS Misalignment: 2021 Scope 92% complete

7. Issue GO data-asset-related guidance documents to address EDM document GOV-9001S by the end of 2021, and to address (planned) EDM Data Quality Standard by the end of 2022.	1. EDM published their first Standard in 12/31/20 and revised 4/15/2021 2. Draft of TD-5001S pending internal review and approval.

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

c. Risk Management Process

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

To identify and address risk, PG&E follows a comprehensive enterprise and operational risk management process. PG&E's Enterprise and Operational Risk Management plans allow PG&E to manage assets and risks at an enterprise and operational level. PG&E defines "Enterprise Risk" as any risk that could potentially have a catastrophic impact to the company. PG&E's Board of Directors provide oversight for Enterprise Risks through annual and ad-hoc risk reviews.

Operational risks are actively managed at the LOB level, with oversight provided by each LOB's RCC, which at a minimum, meet quarterly. The GO RCC meets monthly. Each LOB RCC is charged with oversight of risk management activities within the LOB including, but not limited to, reviewing risk assessments, approving risk response plans, and overseeing their implementation. By assessing and managing risks from both points of view, PG&E can better manage the interdependencies and drive for consistency in risk management across the Company. In addition, there is a Public Safety Risk Council of LOB officers who meet monthly, following an annual work plan which supports Board oversight of Enterprise Risks and provides oversight for the remainder of the Corporate Risk Register (CRR).[14] 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 Board engagement in risk-informed decision-making by involving them in decisions as the process unfolds, and gives those individuals charged with managing specific assets line of sight to other risks across the enterprise. Since the appointment of the Federal Monitor in 2017, the monitor has continued to be actively engaged in PG&E. For example, the monitor attends and participates in GOs' RCC meetings, and also is actively engaged in our IM analyses.

GO identifies, assesses and ranks its risks in a CRR in accordance with the Enterprise and Operational Risk Management guidelines. The GO risks within the CRR are governed by the GO RCC. GOs' risks can be communicated to PG&E's executive leadership team at the Public Safety Risk Council. Risks, including the key 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, GO identified nine operational risks as part of the CRR for 2021. These risks are summarized in Table 10 below.

Table 10 – 2021 Gas Operations Risks in the Corporate Risk Register	
Risk	**Description of Risk and Risk Drivers**
Loss of Containment on GT Pipeline	Failure of a GT 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 NG 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 NG 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 Crossbore.
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 NG 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 NG to customers. Drivers Include: Corrosion, Equipment Failure, Incorrect Operation, Material/Weld Fail, Natural or Other Outside Force.
Loss of Containment at NG 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 NG 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 C&P Facility	Failure at a Gas M&C or C&P 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 NG 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 NG 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 NG 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 LOB 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 LOB, with other impacted LOB providing their input and subject matter expertise. These factors also follow the Enterprise and Operational Risk Management process. GO is impacted by several Cross-Cutting Factors owned by other LOBs as displayed in Table 11 below.

Table 11 – Enterprise Risk Management: Cross-Cutting Factors	
Cross-Cutting Factor	**Description**
Seismic	Seismic events can be a significant driver of failure in all LOB assets. Seismic events contribute to the likelihood of asset failure events and to the associated safety, reliability and financial consequences of those events.
Cyber Security 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, or 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 in which it serves.

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

On July 6, 2020, the CPUC issued an OIR to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities (R.20-07-013) to consider ways to strengthen the risk-based decision-making framework that regulated energy utilities use to assess, manage, mitigate and minimize safety risks. The rulemaking will build on requirements for a utility risk framework adopted in the S-MAP Proceeding (A.15-05-002 et al.) and in R.13-11-006, the Risk-Based Decision-Making proceeding, with the goal to further the prioritization of safety by electric and gas utilities. PG&E will continue to have an active role in this latest proceeding to support improved risk management practices.

d. 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 2021 include:

- Continued physical records remediation in field offices and provided local support during decommissioning of PG&E sites;
- Monitored Gas' maintenance of Information Governance Maturity Model (IGMM) level 3 maturity, as assessed by Lloyd's Register;
- Closed the GT Recordkeeping Order Instituting Investigation (OII) remedy PricewaterhouseCoopers LLP (PwC) E.5 by migrating all 71 GT SharePoint OnPrem sites to SharePoint Online, satisfying the requirement of standardizing the use of stand-alone repositories such as SharePoint so they can align and potentially integrate with RIM procedures going forward;
- Closed the GT Recordkeeping OII remedy PwC E.13, by implementing legal hold functionality in Documentum's OnPrem and cloud environments and developing a formal legal hold process, satisfying the requirement of developing and executing a formal 'hold in place' process for Documentum to facilitate preservation of information and records under legal holds and ensure reporting/auditing of holds is included;
- In support of the GT Recordkeeping OII remedy PwC E.7 to move legacy information and records in shared drives into a central repository, ERIM defined a strategy, selected tools, and identified the 68 GT shared drives in scope for the 2022 migrations; and
- Completed collection of Gas Leak Surveys from all sites and submitted them to offsite storage.

The RIM Ambassador network, composed of ERIM staff and representatives from GO and other LOBs, continues to be an effective way of communicating records management information throughout the LOB. In addition to the mandatory information and records training that all PG&E employees receive, the ERIM team provides quarterly training and discussions on general information and records management practices. These offerings are available to all of PG&E. Additionally, ERIM personnel support all LOB and all regions throughout PG&E by providing records management guidance.

ERIM maintains comprehensive 5-year roadmaps listing projects and initiatives that support our mission and goals. Table 12 highlights key ERIM projects and programs, with the drivers for work impacting the Gas LOB in 2022.

Table 12 – Gas Operations Records and Information Management Roadmap Highlights

Roadmap Projects & Programs	Roadmap Drivers
Gas Shared Drives Content Migration (GT OII Remedy PwC E.7)	Records-related remedies and recommendations adopted by the CPUC in the San Bruno OII Penalties decision issued in April 2015 and outlined in PG&E's Initial Compliance Plan associated with Investigation (I.) 14-11-008, an OII associated with PG&E's gas distribution records management practices
ERIM Program Compliance	• ARMA International's IGMM • PG&E's Records Information Management standards (GOV-7000 series)
Disposition Execution	
Documentum Repository Consolidation	
IGMM Action Plans	

e. 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 NG. 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.

i. Damage Prevention

Damage Prevention consists of multiple processes working in collaboration 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 (L&M), and Pipeline Patrol.

Damage Prevention includes marking the field location of underground facilities as requested through the USA One-Call system—commonly referred to as 811, USA ticket management, investigations associated with dig-ins and damage claims, and Public Awareness. The marking of underground utilities is governed by California Government Code (CGC) 4216 and the process is driven by regulatory requirements and industry best practices. Table 13 describes other key Damage Prevention programs.

Table 13 – 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 noncompliance activity prior to continuing any excavation. In 2021, the Damage Prevention Hotline received 957 calls.
Gold Shovel Standard	PG&E continues to participate in the Gold Shovel Standard. PG&E began this program that is now run by a third-party and available to utilities across the nation. The program sets safety criteria that second-party contractors are required to meet to be eligible to do work on behalf of the Utility. The Gold Shovel Standard became an internationally recognized program, with companies in Canada adopting and implementing its certification requirements. The Gold Shovel Standard program is one way that PG&E is making its own communities safer, but also bringing best safety practices to the industry. PG&E requires contractors excavating on behalf of PG&E to obtain the Gold Shovel certification. PG&E acknowledges all contractors who practice safe excavation and monitor offenders who fail to demonstrate safe practices. Unsafe contractors lose their certification.
Damage Prevention Manual and Training	Providing clear and concise instruction around dig-in prevention measures like troubleshooting "difficult to locate" facilities.

In addition, since 2012, PG&E has improved its "Shut-In 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. In 2021, PG&E's Shut-In The Gas Performance was on average 43.53 minutes for services and 102.6 minutes for mains.

Table 14 – Shut-In The Gas Performance (average number of minutes)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Services	70.00	61.00	52.20	49.00	45.76	45.16	43.30	41.40	41.93	43.53
Mains	192.00	147.00	120.77	102.80	104.43	103.78	88.77	85.13	93.72	102.6

Since 2012, PG&E has improved its overall make safe performance on events involving services by 40 percent, and events involving mains by 49 percent.

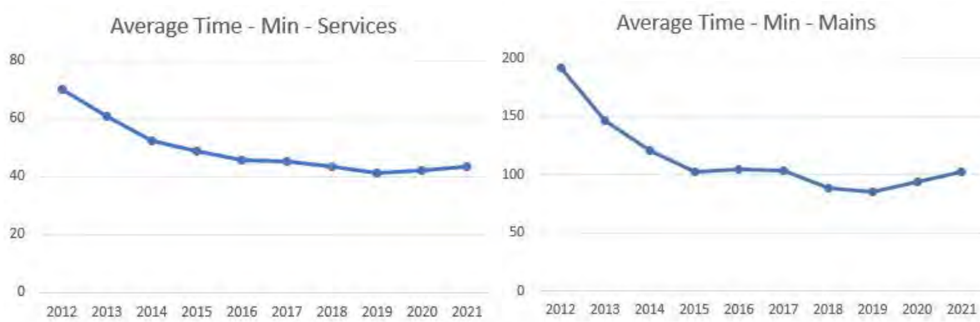

Figure 21 – Shut-In The Gas Performance

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

1. PUBLIC AWARENESS

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

PG&E conducted 137 "811 Call Before You Dig" contractor workshops, reaching 2,254 attendees at 97 companies

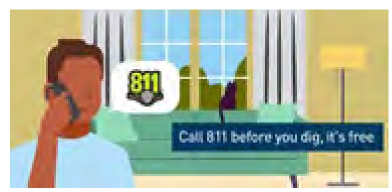

Figure 22 – Screenshot of 811 awareness social media post

PG&E communicates gas safety information multiple times each year, and in 2021, 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 piece to over 350,000 non-PG&E customers within 1,000 feet of a PG&E GT 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 15 identifies highlights from the Public Awareness Program's 2021 activities.

Table 15 – Public Awareness 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 290,000 impressions.
Executed 12 different social media campaigns targeting homeowners and contractors throughout PG&E's service territory, promoting the importance of calling 811 before digging. These campaigns resulted in over 9.5 million impressions.
Conducted monthly webinars during peak digging months, outlining the process for calling 811 and why making the call is so important. Held 11 webinars, which had over 700 attendees.
Completed 6 bilingual 811 workshops, with 160 participants (farm workers), in partnership with local Spanish language radio stations. Conducted an interview with each radio station to further expand on the 811 free service. In addition, our Spanish 811 jingle was aired over 700 times reaching approximately 150,000 Spanish speaking customers.
Continued to conduct targeted outreach in cities with a high number of dig-ins. The outreach included job site visits, 811 training for top damaging companies and meeting with local leadership to discuss continued partnership for community safety. These targeted efforts resulted in over 5,300 field visits by DiRT Investigators.

2. 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 and 0.91 in 2021. Table 16 below provides information on some dig-in prevention projects or process improvements.

Table 16 – 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.

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

3. Locate and Mark Program

The L&M Program is designed to mitigate the potential risk of damage to underground facilities by identifying and marking assets for potential excavators within a 48-hour window. Federal pipeline safety regulations[15] and California state law[16] 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 NG, 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 2021, PG&E received over 1.7 million USA ticket notifications.

In December 2018, the CPUC opened an OII involving data that PG&E maintained from 2012 to 2017 regarding the timeliness with which it responded to 811 notifications.[17] PG&E takes the issues raised in the OII seriously and has worked hard to correct them since they were brought to senior management’s attention. As such, PG&E implemented a comprehensive corrective action plan (Compliance Plan) with demonstrated results. This Compliance Plan identified 30 corrective actions across five core areas: Cultural, Process & Procedures, Tools & Technology, Employees & Contractors, and Internal & External Controls. Of the Compliance Plan’s 30 corrective actions, all 30 were completed in 2019.

In October of 2019, PG&E entered into a settlement agreement with the Safety and Enforcement Division of the CPUC to undertake several enhancement initiatives to the entire Damage Prevention program, all at shareholder expense. In addition to the enhancements to the Damage Prevention programs, PG&E agreed to take specific actions to reinforce its commitment to a Speak Up culture, expectations on identifying and reporting fraud and holding leaders accountable for violations of its Code.

The L&M OII Settlement agreement was amended and approved by the Presiding Officer on February 14, 2020 and approved by the Bankruptcy court, establishing the settlement agreement effective date as April 24, 2020. PG&E has made significant progress on implementing the items contained within the settlement agreement including, but not limited to:

- Developing an internally created USA ticket management system with improved controls, increasing internal locating staffing;
- Hiring qualified electrical workers within the L&M Department;
- Updating training for locators, requiring contracted locating companies to obtain special training accreditation;
- Enhancing QC measures; and
- Continuing to investigate all dig-ins resulting in a gas release or a damaged electric cable.

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

4. Pipeline Patrol

Pipeline Patrol is a federally required activity that is essential to protecting the integrity of PG&E GT facilities from external threats and in doing so, helps to increase public safety. Patrol is performed both aerially and by ground operator-qualified personnel who observe surface conditions on or near the surface of buried pipelines. Patrollers identify and respond to excavation activity (e.g., digging, ripping, boring, blasting etc.), in order to notify excavators they are digging in the vicinity of the pipeline, and in the case of unauthorized digging, to advise use of the USA System.

Figure 23 – Example of Land Movement

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

Figure 24 – Patrol Fixed Wing Aircraft

PG&E primarily utilizes aerial methods to conduct patrols, with ground personnel dispatched to investigate observations made from the air. Exceeding the minimum federal requirements, PG&E's Pipeline Patrol Program seeks to patrol the GT Right-of-Way (ROW) on a continual basis, covering the entire the GT system at least 12 times per year, and often will perform additional patrolling as able. Special patrols may also be performed following natural disasters or other incidents as necessary. Aerial patrols provide real-time knowledge of on the ground activities and the surveillance helps PG&E to identify and stop unsafe excavation practices before dig-ins occur.

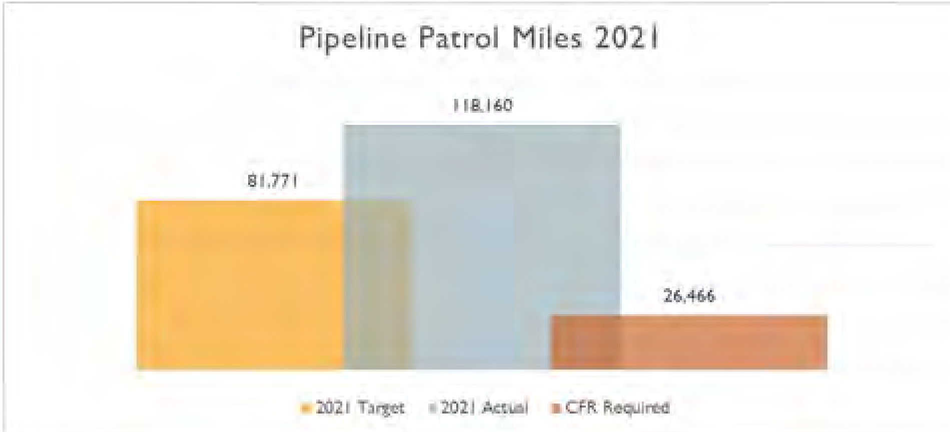

Figure 25 – 2021 Patrols Compliance Status

PG&E patrols an average of 9,000 GT miles per month using a combination of fixed wing aircraft and helicopters. In 2021, 55 percent of aerial observations were related to excavation, 18 percent to new construction, and the remaining include ROW encroachments, geohazards, and pipeline damages.

ii. Pipeline Markers

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

Pipeline Markers are signs on the surface above or near the NG 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 26.

Figure 26 – 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 NG pipelines are in the area, subject to third-party removal or damage, despite being properly installed.

iii. Distribution Pipeline Replacement

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

PG&E has three pipeline replacement programs: Gas Pipeline Replacement Program (GPRP), Plastic Pipe Replacement Program, and Main Replacement Reliability Program. PG&E's objective is to achieve a removal rate of pre-1985 pipe that limits asset age to nearly 100 years by 2030.

Table 17 – Pipeline Replacement

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 2021, the GPRP Program replaced 36.9 miles of pipe.	Since PG&E began its Plastic Pipe Replacement Program in 2012, PG&E has replaced about 700 miles. In 2021, 136.3 miles of Aldyl-A were replaced. PG&E continues to increase the replacement of Aldyl-A year over-year in recognition of the approximately 4,800 miles of known inventory.	The Main Replacement Reliability Program focuses on the replacement of pipeline not covered by the GPRP or Aldyl-A programs and will continue to help move the distribution systems average age closer to the national average. In 2021, PG&E replaced 18.2 miles of distribution pipe through this program.

Figure 27, below, demonstrates the company's main replacement progress from 2010 to 2021.

Program			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Main Replacement 2010-2021 Actuals														
14A	GPRP	Replacement of all cast iron and some steel main installed pre-1940	24.8	28.1	23.4	31.6	26.8	27.5	30.4	35.8	43.6	20.0	24.4	36.9
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	90.0	87.4	136.3
50A	Reliability	Replacement of gas facilities that have reliability concerns but do not qualify for replacement under the GPRP or Aldyl-A Plastic Replacement Programs	3.7	6.4	7.9	8.2	6.6	13.7	15.8	14.1	28.6	16.0	19.2	18.2
Total			28.4	34.4	48.9	70.5	65.9	104.7	126.6	145.0	163.4	126.0	131.0	191.4
Trend				21%	42%	44%	-7%	59%	21%	15%	13%	-23%	4%	46%

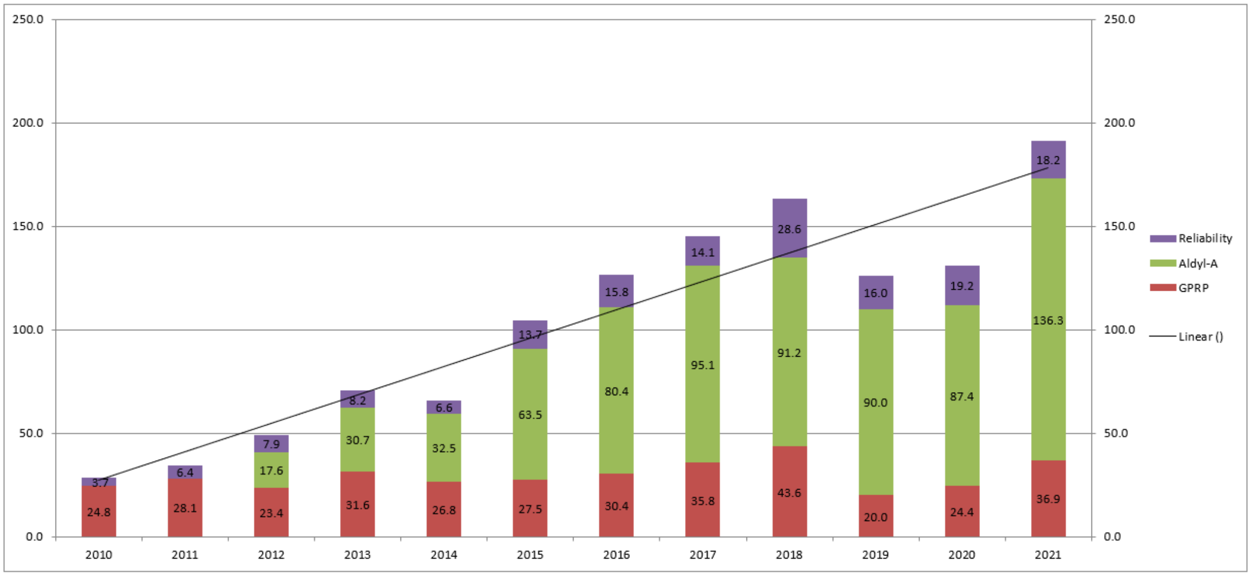

Figure 27 – Main Replacement Progress 2010-2021 (in miles)

iv. Cross-Bore Mitigation

A cross-bore[18] is a gas main or service that has been installed unintentionally, using trenchless technology, through a wastewater or storm drain system. PG&E has an inspection program to identify and remediate gas cross-bores, and a public outreach program that provides safety information to PG&E customers, sewer districts, and public works agencies. In addition, PG&E has implemented a Gas Cross-Bore Inspection Program that uses video camera inspections to verify no damage has occurred to sewer lines when using trenchless construction methods on new construction projects.

Cross-Bore Statistics			
Year	Inspections Completed	Cross Bores Found	Inspections Planned
2013	19,298	148	25,000
2014	33,804	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	28,423	37	41,636
2020	16,665	56	15,000
2021	28,293	33	27,532

Figure 28 – Cross-Bore Statistics

The goal of PG&E's Cross-Bore Inspection Program is to identify cross-bores by completing inspections of potential conflict locations and repairing all occurrences as they are discovered. PG&E completed approximately 28,293 inspections in 2021. In 2021, PG&E found approximately 1 cross-bore per 857 inspections.

v. 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 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 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.

Figure 29 – Strength Test in Progress

PG&E continues to strength test or replace untested transmission pipelines in compliance with Pub. Util. Code Section 958. In 2021, PG&E completed approximately 32 miles of strength testing (Table 18), of which 13.7 miles were re-tested for specific IM purposes. This work brings PG&E to a total of approximately 1,567 miles strength tested since 2011. The pipeline miles strength tested in 2021 were prioritized based on a risk informed mix of IM threats and testing untested pipe lacking a traceable, verifiable, and complete record to meet the National Transportation Safety Board (NTSB) D.11-06-017 requirements.

Table 18 – Strength Testing Program

Strength Test (miles)	2011-2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
PSEP	539	135	N/A	N/A	N/A	N/A	N/A	N/A	N/A	674
Subsequent Testing	0	0	79	89	253	286	115	39	32	893
Total	**539**	**135**	**79**	**89**	**253**	**286**	**115**	**39**	**32**	**1567**

PG&E will continue to concentrate on assessing shorter pipeline segment tests addressing NTSB commitments (D.11-06-017) and re-assessing pipeline segments with IM threats for both manufacturing related defects and time dependent corrosion threats.

vi. VINTAGE PIPE REPLACEMENT

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

In 2019, PG&E refreshed its program information using new risk results from the previous year. This update continued with our strategic risk prioritization approach to replacing pipe where PG&E defines high-risk land movement areas, prioritizes projects based on total risk, and defines pipe with lower risk to be monitored for risk change through our ILI and Geohazard programs in lieu of replacement or retirement. Based off this risk methodology and updated risk results, PG&E has now identified approximately 123 miles (Tier 1 and Tier 2) of transmission pipe,[19] with some of the characteristics that make it more susceptible to certain construction threats. Of those 123 miles identified, PG&E has further identified approximately 118 miles (Tier 1) of high risk pipe targeting replacement or retirement where vintage fabrication and construction threats interact with high likelihood of land movement in populated areas.[20] Additionally, PG&E is monitoring an additional 1,542 miles of pipeline with vintage characteristics through the ILI and Geohazard programs. In 2021, approximately 3.22 miles of vintage pipe were replaced.

Figure 30 – Vintage Pipe Replaced in San Rafael

Table 19 – 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
Program Target:	123 miles		100 percent

(a) High risk mileage addressed includes pipeline retirements and mileage replaced in other pipe replacement programs from 2015-2021 that have the vintage threat.

As PG&E continues to monitor and assess characteristics of vintage pipelines interacting with land movement through improved data quality and collection, its replacement or retirements are prioritized by addressing sections of pipeline closest to highest density population areas with a high likelihood of ground movement. At PG&E's current and planned rate, the program will address the risk of pipe containing vintage fabrication and construction threats that interact with high risk of land movement for high population density areas by 2030.

vii. In-Line Inspection

PG&E's ILI Program uses technologically advanced inspection tools, often called "smart pigs," to reliably 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. Pipeline features that would obstruct the passage of the tool to make the pipeline piggable must also be replaced. After the pipeline is upgraded to accommodate an ILI tool, cleaning and inspection "runs" are conducted to collect data about the pipe. This data is analyzed for pipeline anomalies that must be remediated through the Direct Examination and Repair process where the anomaly is exposed, examined and repaired as necessary. The information from Direct Examination and Repair is used to generate mitigation activities to improve the long-term safety and reliability of the pipeline.

Figure 31 – Electro Magnetic Acoustic Transducer 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 2021, approximately 45 percent of the system is piggable. In addition, PG&E inspected a total of 949 miles with 396 of those miles assessed with ILI for the first time. Much of PG&E's pipeline was installed decades before ILI was invented. Today, about 31 percent of the PG&E system is not capable of supporting the running of traditional ILI tools because of design elements like low pressure and/or low flows, small diameter pipelines, and short sections of pipeline or facility configurations, such as drips or blow downs. Figure 32 details PG&E's progress to -date to upgrade pipelines to make them capable of accepting traditional ILI tools.

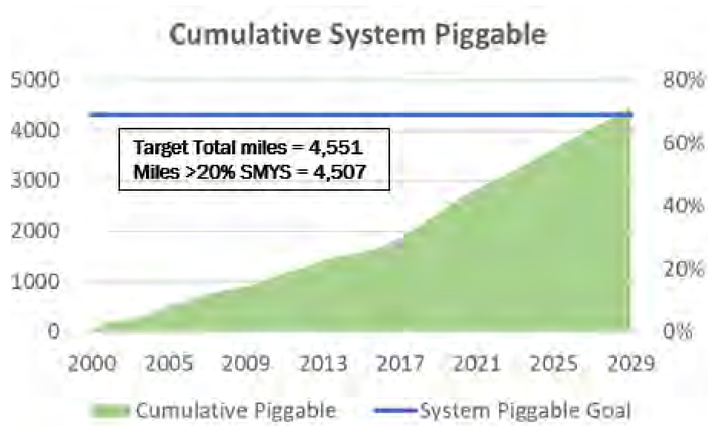

Figure 32 – Progress to-date to upgrade pipelines

viii. 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. GT, storage, and distribution assets primarily composed of steel pipe carrying compressed NG may experience degradation due to External Corrosion, Internal Corrosion, or SCC. External Corrosion is degradation of the pipe due to interaction of the steel with the atmosphere, soil (buried piping), and/or water (submerged piping). Internal Corrosion is degradation of the pipe due to interaction of the steel with the NG being transported or with unintended product such as water, solids, salts, etc. SCC is degradation of the pipe due to cracks induced from the combined influence of tensile stress[21] 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 NG. PG&E assesses the risk of External Corrosion, Internal Corrosion, and SCC independently because each requires a different form of mitigation.

Figure 33 – PG&E Employee Installing a Cathodic Protection Rectifier (Photo Captured Pre COVID-19)

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 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 below:

Table 20 – 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 is implementing 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 Resurvey	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. PG&E actively participates in corrosion research conducted by the Pipeline Research Council International (PRCI) and supports efforts to incorporate the results of such research into corrosion control regulations and standards through its participation in 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).

ix. Earthquake Fault Crossings

PG&E's Fault Crossings Program addresses the specific threat of land movement at active earthquake faults that subject a pipeline to external loads due to seismic events. The program is consistent with California law that requires NG operators to prepare for and minimize damage to pipelines from earthquakes. PG&E performs system-wide studies to address both the anticipated geologic movement and pipeline mechanical properties to manage the integrity of the pipe

(Table 21). Additional mitigation work is then prioritized, following each study, by considering the likelihood of failure (the probability that the fault will trigger a seismic event), and the consequences of failure (including the impact on the local population, PG&E system reliability, and the environment). Mitigation typically includes modified trench designs, trench adjustment, pipe replacement, or installation of automated isolation valves.

Table 21 – Earthquake Fault Crossing Program

	Studies[g]	Crossings Mitigated[h]
Pre-2015	52	24
2015	65	18[a]
2016	65	6[b]
2017	22	7[c]
2018	34[i]	25[d]
2019	12	12[e]
2020	38[f]	4
2021	8[j]	2

(a) 2015 – 14 crossings were Fit-for-Service (FFS) per current design. 4 crossings replaced.

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

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

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

(e) 2019 – 6 crossings were FFS per current design and 6 crossings were replaced.

(f) 2020 – 17 crossings were FFS per current design and 4 crossings were replaced.

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

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

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

(j) 2021 – Studies of 38 crossings were initiated. 8 were completed.

Figure 34 - L-301A Fault Crossing Pipe Replacement

x. LEAK SURVEY

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

PG&E outlines current requirements, standards, and guidelines for the Leak Survey and Detection Program in its procedures. In 2021, PG&E surveyed over 1.4 million gas distribution pipeline services, over 13,000 GT pipeline miles, and performed daily leak surveys on 108 wells in compliance with CalGEM's emergency gas storage regulations. In addition, PG&E completed California Air Resources Board (CARB) Leak Survey at the 13 GT Compressor/Storage Well Facilities, consisting of 148,294 individual components. PG&E also performed Daily Leak Survey of the three Storage Well facilities (PC, LM and McDonald Island) as part of the COGR (CARB Oil and Gas Rule) was completed successfully 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 Picarro technology in all of its divisions, completing at least 75 percent of its gas distribution compliance survey. The expanded use of the Picarro technology and the acceleration of leak survey cycle will continue to support PG&E in its ability to: (1) find and fix more leaks, thereby eliminating more potential hazards to the public; and (2) reduce GHG emissions.

In addition, in 2021, 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 10 standard cubic feet per hour of methane. As a result, in 2021, PG&E completed the Super Emitter survey on 100 percent of its gas distribution services. The purpose of this survey is for Picarro to identify and measure the leak flow rates of Super Emitters as they are found during compliance survey. The data will then inform PG&E of the prevalence of these leaks and the emission reduction that can be gained by repairing them quickly.

To further enhance its leak survey process, in 2019, PG&E implemented technology to enable an end-to-end paperless transmission leak survey process and integrated with enterprise systems. Initiatives are in progress to continue to build and support a full end-to-end paperless process for distribution leak survey. In 2019, PG&E implemented an application that allowed Leak Survey to create and document all leaks electronically. This same application was updated in late 2020 into 2021 to perform all leak rechecks and gas samples paperless and updates the system of record the same day.

In accordance to maintain public safety, PG&E purchased through our Capital Tool Purchase program 150 new DP-IR+(DetectoPak-Infrared+) and 180 new RMLD CS(Remote Methane Leak Detector CS) leak detection units to replace our aging equipment. We will also be utilizing drones with Open Path Spectrometry (OPS) leak detection units to fly our submerged transmission pipelines. This will reduce some road closures and keep our survey team off navigable waterways with boats.

In 2021, PG&E expanded on previous process improvement initiatives and introduced new customer communications to mitigate the 19,600 Leak Survey Can't Get In (CGI) inspection backlog. PG&E expanded upon its online customer scheduling portal, introducing custom links sent to customers via text message that allowed them to schedule thousands of service appointments within a few minutes using only their smartphones. Customers also continued to receive and book appointments through custom portal links received via email to allow for quick and easy appointment scheduling through a computer. In addition, PG&E created a new Gas Meter Safety Inspections page emphasizing the importance of gas meter safety inspections on PGE.com and shared the new page via email and mailed newsletters to millions of customers to encourage them to grant PG&E access to conduct Leak Survey work. With these CI efforts, despite continued unprecedented challenges caused by COVID-19, PG&E was able to decrease the backlog of Leak Survey CGIs from 19,600 to 9,206 by the end of 2021. PG&E continuously reported the monthly status of the backlog and was granted extensions to the Resolution M-4845 waiver throughout 2021, enabling further efficiencies in geographical CGI bundling. Res. M-4845 allowed PG&E to continue to adjust specified pipeline operations and maintenance survey activities due to COVID-19 public safety concerns. At the end of 2021, PG&E was able to reinstate an improved service disconnection process that had been stood down for the first 22 months of the pandemic. PG&E will utilize the latest Res. M-4845 waiver extension, granted specifically for the 2021 backlog, to further reduce the historical backlog of Leak Survey CGIs while continuously working to meet 2022 compliance. Summaries of PG&E's 2020 Leak Survey cycles for its distribution and transmission pipeline systems are shown in Table 22 below:

Table 22 - Leak Survey Frequency

Facility Types[1]	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)

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Note: See Utility Procedure TD-4125P-10, "Identifying Gas Transmission Assets."

xi. Leak Repair

Pipeline safety regulations and California state code require PG&E to repair certain leaks. In 2021, PG&E's trained and operator- personnel assigned 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 2021, PG&E repaired 2,190 below-ground Grade 3 distribution leaks to further reduce GHG emissions.

In 2021, PG&E used its CI approach to continue more efficiently bundling and scheduling leak repairs. Identifying all the work required in an area at one time provides opportunity to bundle work locations and effectively maximize the utilization of resources. In 2021, PG&E repaired over 20,000 gradable leaks on the gas distribution and transmission system.

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

In 2021, 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 <150 days and exceeded that goal with the average days open of 113 days for 2021.

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.

xii. Overpressure Elimination Initiative

A pipeline that operates at higher than the MAOP presents an operational risk to the safety of the public, employees, and contractors working on the facilities. When a pipeline operates above its MAOP, it is known as an abnormal operating condition (AOC) 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 36) 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

Figure 36 – Large Overpressure Events (2011 – 2021)

points to increase system real-time visibility in the Gas Control Center (GCC), while Large Volume Customer primary regulation sets also received accelerated inspections.

In 2018, PG&E began its strategy to install secondary overpressure protection devices on pilot-operated regulation equipment.[22] PG&E has a strategic goal of eliminating the common failure mode at 50 percent of our pilot-operated sites by the end of 2022. This objective will be met predominantly by the installation of secondary OP protection devices (slam shut devices). The reasons why pilot-operated regulation equipment is particularly vulnerable to large OP events are twofold: (1) they can fail due to gas quality issues, such as debris, sulfur, liquids, or black powder; and (2) they tend to have a design that causes both the regulator and the monitor to fail in an open position (common failure mode), therefore resulting in a loss of regulation. PG&E currently has 1,535 distribution pilot-operated regulation stations and 572 transmission pilot-operated stations. At the end of 2021, PG&E had a total of 811 pilot-operated stations in which the common failure mode has been mitigated (38.5 percent of the total population).

At the end of 2018, the NTSB published a Safety Recommendation Report in response to a September 2018 overpressurre 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 ensure damage to a sensing line cannot create an OP event. Work is on-going to explore additional controls 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.

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

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, and the third iteration was published in July 2021. The plan is for the Roadmap to be updated annually.

In 2021, PG&E tied the company record for the lowest number of large OP events recorded in a single calendar year (5) since 2011. A key component of this result is that only 1 equipment-related large OP event was recorded in 2021, which is a reflection of the success of our strategy of installing secondary overpressure protection devices on pilot-operated regulation equipment. Other key factors in this result are the continued emphasis on human performance development and training, along with additional rigor that has been implemented around the clearance development and execution process.

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.

xiii. COMMUNITY PIPELINE SAFETY INITIATIVE

STRUCTURE MILES | >99% ADDRESSED			
YEAR	ACT+ FSCT	PERCENT	COMPLETE
2013	5.00	1%	5.00
2014	110.00	32%	110.00
2015	93.00	58%	93.00
2016	114.00	89%	114.00
2017	30.00	98%	30.00
2018	7.60	99%	7.60
2019	0.25	99%	0.25
2020	0.00	99%	0.00
2021	0.0191	99%	0.0191
2022	**0.094**	**100%**	**0.00**
TOTAL	**360.00**	**-**	**359.90**

VEGETATION MILES | >99% ADDRESSED			
YEAR	ACT+ FSCT	PERCENT	COMPLETE
2013	115.00	7%	115.00
2014	146.00	17%	146.00
2015	380.00	41%	380.00
2016	540.00	76%	540.00
2017	258.00	93%	258.00
2018	86.60	98%	86.60
2019	18.03	99%	18.03
2020	0.26	99%	0.26
2021	0.91	99%	0.91
2022	**8.38**	**100%**	**0.00**
TOTAL	**1,553.20**	**-**	**1544.60**

Figure 37 - Structure and Vegetation Miles Addressed

PG&E's Community Pipeline Safety Initiative (CPSI) is a shareholder-funded program that focuses on enhancing the safety of the gas pipeline by addressing items located too close to the pipe that 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.

In December 2013, the program conducted a comprehensive centerline survey that allowed PG&E to locate its pipeline and collect data on trees, brush and structures located above the pipeline. Based on the survey results, PG&E identified 1,553 vegetation miles and 360 structures miles with items that needed to be addressed. The program was initially anticipated as a five-year initiative ending in December 2017 but has been extended through at least December 2022 due to long-lead permitting and outstanding municipality and customer agreements. To date, the program has cleared more than 99 percent of the work, including approximately 1,544 vegetation miles and 359.9 structure miles. The remaining 8.38 miles of vegetation and 0.0191 miles of structure clearing are primarily located in Lafayette, Palo Alto, San Jose District 6 and Santa Cruz County, with a few one-off projects in other locations.

For areas with completed CPSI work, PG&E remains committed to keeping the area above and around the pipeline clear through our ongoing Gas Transmission Vegetation Management (GTVM) Program.

xiv. Gas Transmission Vegetation Management

PG&E's GTVM Program regularly inspects the area above and around the pipe to look for any new structures, trees or brush that could block access to a pipeline during an emergency or for critical maintenance work. We also review trees previously left in place as part of CPSI to determine if they have developed into a safety concern.

The GTVM program inspects at least one-third (approximately 2,270 miles) of the GT pipeline system each year. Vegetation and structures identified during inspections are typically addressed the following calendar year. In 2021, crews patrolled 2,587 miles of GT pipeline. In addition, vegetation crews cleared 243 miles that had new brush, resprouted vegetation or trees that posed a safety risk to the pipeline. Prior to proceeding with work, PG&E requests the property owner self-perform the identified vegetation but will remove the vegetation at no cost to the owner if they are unable to self-perform. The team also addressed 89 structure encroachments. For any structure encroachment identified, PG&E works with the property owner to remove or relocate the structure at the property owner's expense.

In addition to conducting inspections and addressing identified safety concerns, PG&E also partners with our communities to increase awareness of the gas pipeline and importance of keeping the area safe and clear. We have found that by working together, PG&E and the community can reduce safety risks and prevent accidents and damage to the pipeline.

f. 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[23]. Loss of gas service can also lead to extinguished gas pilots and the subsequent potential for uncombusted gas entering 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 2021, PG&E transported and delivered about 1.012 trillion cubic feet of gas, a 2.7 percent increase from the previous year.[24] 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.

i. 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 23 – 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.

ii. 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 is in compliance with 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 winter system performance.

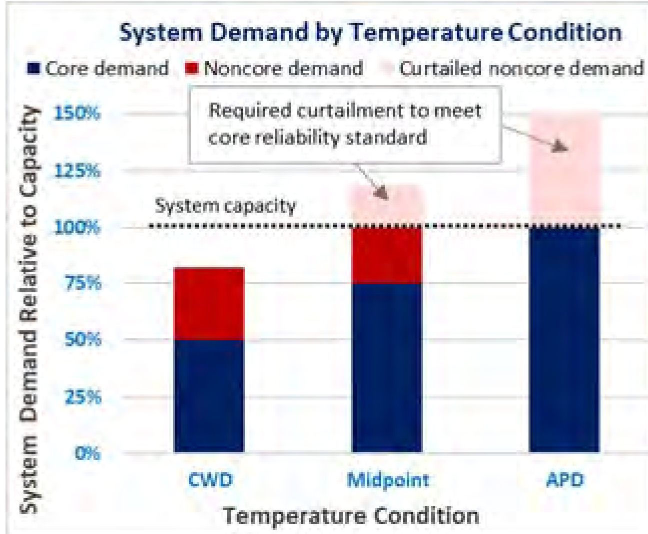


Figure 38 – Conceptual Representation of a Noncore Curtailment Plan

iii. OPERATIONS FOR FACILITATING SAFETY WORK

In some cases, the measures necessary to mitigate the risk of loss of containment require a temporary reduction in the capacity of a gas system. For example, conducting a strength test requires taking a pipeline out of service. If pipeline anomalies are discovered through ILI, the operating pressure of a system may need to be reduced until the anomalies can be further examined and repaired. The following measures are taken to mitigate the risk of loss of gas supply when performing safety work.

Safety work is scheduled such that adequate supply to customers is maintained, as practical. If adequate supply is unavailable, planned service outages 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.

Particular to traditional ILI, new guidelines were introduced in 2021 that require contingency plans be developed to mitigate the risk of loss of supply in the low probability event that an inspection tool gets stuck in the line and restricts supply to the downstream system. If the risk cannot be fully mitigated, an emergency curtailment plan will be developed and undergo leadership approval in advance of the inspection.

g. Mitigating the Risk of Inadequate Response and Recovery

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

- Plan for natural and manmade emergencies such as fires, floods, storms, earthquakes, cyber disruptions, and terrorist incidents;
- Respond rapidly and effectively, consistent with the National Incident Management System principles, including the use of the Incident Command System, to protect the public and to restore essential utility service following such emergencies;
- Help alleviate emergency related hardships; and
- Assist communities to return to normal activity.

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

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

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

Figure 39 – Key Incident Response Objectives

PG&E uses the structure of the Incident Command System to complete key steps in responding to incidents. The key incident response objectives in Figure 39 represent a typical process flow through the cycle of an incident. However, incidents may not necessarily follow this exact sequence. For example, it may be appropriate to "Make Safe" at several points during the response process and not just after "Assess the Situation."

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

i. Gas System Operations and Control

PG&E's GCC monitors and controls the flow of gas across PG&E's system 24 hours a day, 365 days per year, so that NG 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 40 – PG&E's Gas Control Center Features a 90 Foot-Long Video Wall With Current Operational Information to Augment The Gas SCADA System (Photo Captured Pre COVID-19)

PG&E's GT 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

Transmission	3,307 Transmission SCADA points[1]	100% Visibility into Transmission system Backbone	57% Visibility into Transmission local transmission	124 Transmission Devices installed 2011-2021
Distribution	5,50132.4K Distribution SCADA points[1]	74% Visibility into Distribution system		1,915 Distribution Devices installed 2011-2021

(1) Note: PG&E continually evaluates improvement measures to represent the extent and capabilities of the SCADA system. To improve the clarity and meaningfulness of this table's information SCADA points that directly impact safety-related visibility, monitoring and response performance have been included, therefore the 2021 data is a substantial reduction in point counts from prior years. For comparison, prior year point counts using the improved methodology can be provided upon request for a like-for-like comparison. .

Figure 41 – PG&E's Progress in Enhancing System Visibility Through SCADA

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—

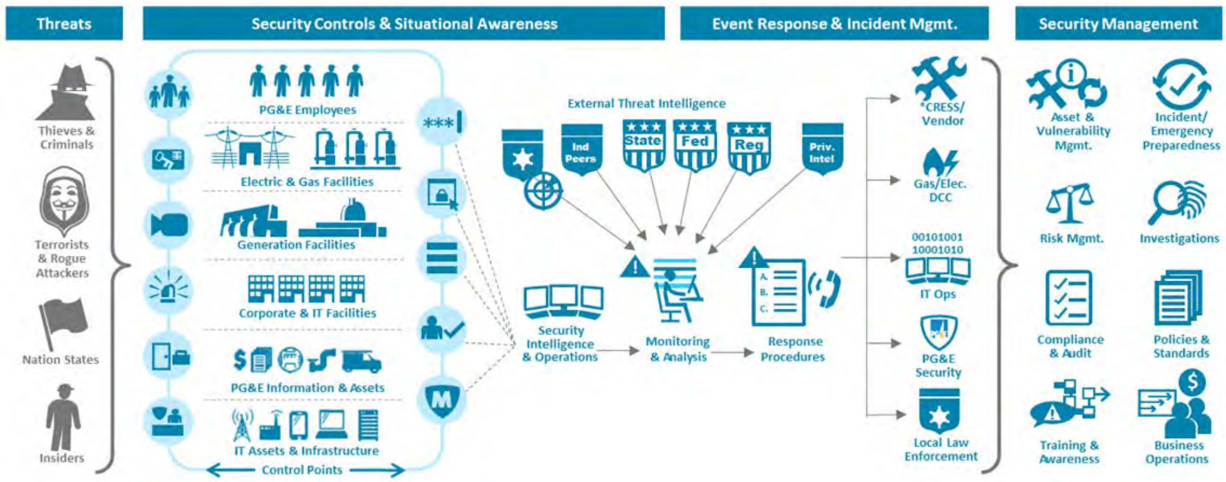
the ability to identify, process, and comprehend the critical elements of information about what is happening. Billions of data records, composed of a mix of near real-time gas system operational data and a variety of geospatial, time dependent, and historical information that relates to the gas system 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.

ii. 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. 2021 included efforts to collect key information on clearance supervisors, and establish recommended rankings (CS1 or CS2) to understand the volume of training needed starting in 2022. Clearance training has had a complete revamp; the base course is now a five day class and includes experiential exercises for writers, endorsers and clearance supervisors. Course design was also completed for distribution endorsing and executing of clearances, which will launch in Q1 of 2022 .

iii. 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 informed risk decision making necessary to support PG&E's mission.



NOTE: CRESS is Corporate Real Estate Strategy and Service

Figure 42 – PG&E Unified Cyber/Physical Security Program Effectively Manages Risk and Proactively Adapts to Evolving Threats and Changing Business Needs

PG&E's Corporate Security Fusion Center team tracks emerging and evolving activity which may pose a threat to the well-being of PG&E's employees, customers, and business enterprise. Identified threats are then mitigated at the appropriate levels.

PG&E's Threat Intelligence team tracks evolving cybersecurity 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.

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

- Identifying cybersecurity risks and defining mitigating strategies;
- Building, deploying, and operating effective security technologies and processes;

- Proactively monitoring for and responding to cyber-threats; and
- Collaborating with public and private entities to drive standards and best practices.

Figure 43 – Examples of Active PG&E Government Partners

PG&E's natural GO incorporate significant risk management activities, including those that address cyber and physical attack threats. PG&E's Cybersecurity organization advises GO 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 Department of Homeland Security's (DHS) Transportation Security Administration (TSA) in response to the TSA's Security Directives, issued in 2021, which require assessment and implementation of security measures.

PG&E's Corporate Security organization advises GO on physical security risk mitigation and mitigation activities to physically protect LOB identified operational assets and cyber systems/assets from attacks through physical means. There are two different teams within the Corporate Security organization which are responsible for performing this function:

- The Critical Infrastructure Protection & Compliance team is responsible for all sites identified by the LOB as LOB Critical or U.S. DHS TSA Critical; and
- The Physical Security team is responsible for all other sites.

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 AGA, the Downstream NG Information Sharing and Analysis Center, and TSA calls and briefings and exercises. For example, the 2021 PG&E GridEX VI Functional Exercise was a two-day exercise for utilities and other stakeholders from North America that provided an opportunity for the organization to exercise how it would detect, respond, and recover from simulated severe cyber and physical attacks. Participants simulate internal and external operational activities as they would during an actual event. Exercise objectives include the following: exercise incident response plans;

expand local and regional response; engage critical interdependencies; increase supply chain participation; improve communication; gather lessons learned; and engage senior leadership. It is through the results of security exercises that PG&E is better able to identify and plan control improvements that strengthen Gas Safety.

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

The Valve Automation Program builds upon the scope and principles in PG&E's Pipeline Safety Enhancement Plan that replaced, automated, and upgraded gas shut-off valves across PG&E's GT system starting in 2011 for a total of 381 through 2020. In 2021, an additional 18 valves were automated through the Valve Automation Program.

v. Emergency Preparedness and Response

PG&E's Gas Emergency Response practice is documented primarily in the Gas System Operations (GSO) Control Room Management Manual and the Gas Emergency Response Plan (GERP).

1. Gas System Operations Control Room Management Manual

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

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

To maintain compliance and aid in the management of abnormal and/or emergency operating conditions, PG&E regularly trains gas control personnel on the GSO Control Room Management Manual.

2. 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 3.

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.

3. Gas Emergency Response Plan

The GERP[25] provides detailed information about PG&E's response to gas emergencies. It supports the response to all emergencies broadly as "One PG&E" through the integration with the CERP and the other LOB emergency response plans, which are annexes to the CERP. For 2021 changes to PG&E's GERP, please see Attachment 3.

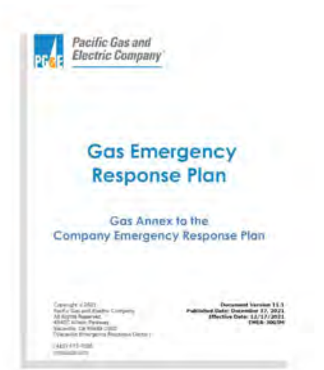


Figure 44 – The Gas Emergency Response Plan as of December 17, 2021

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

The GERP outlines gas specific criteria to PG&E's Incident Levels that are provided in the CERP. The Incident Levels categorize and support PG&E in understanding the complexity of an incident and the actions that may be employed at each level (e.g., emergency center activations, resources requests, etc.).

To ensure a consistent and well-coordinated response to emergencies, the Company has adopted the following incident classification system:

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

4. Gas Emergency Preparedness Team

The Gas Emergency Preparedness Team assists GO with emergency planning, preparedness, response, and review. This group maintains the GERP, leads exercises, facilitates after action reviews, and participates in industry activities designed to impart best practices. The group facilitates the use of the Incident Command System: a systematic, proactive approach for all levels of governmental and non-governmental organizations and the private sector to work together during an incident to reduce the loss of life, damage to property and harm to the environment. Further, the team supports the Gas organization's local emergency centers, called Incident Management Teams, and the Gas Emergency Center, which is co-located with the GCC. These centers are activated according to criteria outlined in PG&E's GERP.

Throughout 2021, the Gas Emergency Preparedness Group:

Completed 100% of IMT (Incident Management Team) and GEC (Gas Emergency Team) team ICS (Incident Command System) 100/200 training

Facilitated 3 Well Control exercises and 7 Lunch and Learn sessions on the Incident Command System

Supported the response to 5 emergency activations impacting Gas Operations

Frequent outreach to first responders helps strengthen how PG&E coordinates when emergencies happen. Due to mandated COVID-19 safety protocols, the PG&E Public Safety Specialists (PSS) were limited to distanced-based (virtual) outreach engagements, throughout 2021. Additionally, COVID-19 considerations appreciably impacted the availability of external public safety partners in their engagement with PSS members. In 2021, Public Safety Emergency Preparedness completed the following efforts in partnership and close coordination with first responders and local governments:

Figure 45 – Delivered First Responder Workshops virtually. These workshops train First Responders to safely respond to gas and electric emergencies and exactly how to access the PG&E GT pipeline mapping system. (Photo Captured Pre COVID-19).

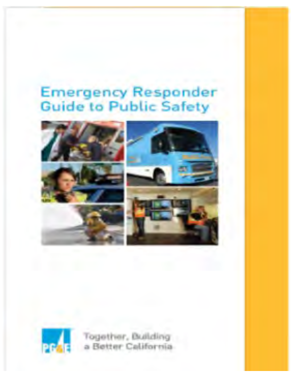


Figure 46 – Met with fire departments responding to gas incidents. These meetings focused on contingency plans in the event of an emergency.

Figure 47 – Performed Public Safety Liaison functions virtually across the service territory to share PG&E's emergency response plans. Representatives from federal, state, county and city governmental agencies attended these meetings. (Photo Captured Pre COVID-19).

Figure 48 – Emergency Management and Public Safety attended and presented Public Safety materials for both gas and electric throughout 2021 virtually. (Photo Captured Pre COVID-19).

Figure 49 – Supported incident response activities (including dig-ins). Public Safety Emergency Preparedness acted as an Agency Representative between PG&E and the first responder community. (Photo Captured Pre COVID-19).

Figure 50 – Supported five 811 Dig-In Reduction and safety-related activities in collaboration with the Damage Prevention team to improve safety within PG&E's communities and reduce the incidents of third-party dig-ins. (Photo Captured Pre COVID-19).

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 a certain task. PG&E annually reviews its PPE Matrix to evaluate the appropriateness of current PPE requirements. Employees in the field also document the controls for any identified hazards associated with their tasks using a Job Site Safety Analysis (JSSA) form. PG&E's PPE Matrix and JSSA are vital resources for employees as they plan their work prior to executing in the field.

In addition to typical PPE, the onset of COVID-19 in 2020 required leaders and employees to adapt to new COVID-19 PPE requirements. The Pandemic Response Team (PRT) was established in 2020 to interpret and implement ever changing CDC guidance, as well as state and local regulatory requirements. PRT made frequent updates to Gas and Enterprise COVID-19 PPE guidelines and communications with a heavy emphasis on employee and public safety.

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

b. Workforce Safety Projects

In 2021, 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 GO in 2021 and their progress and successes:

RSI Guard – GO 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. GO performed at 95.25 percent overall break compliance in 2021, exceeding the goal of 85 percent compliance.

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. NCL timely reporting has increased between 2013 and 2021. In 2021 there was a slight increase in reporting of injuries within the first day by 0.4 percent (as seen below):

Table 24 – Gas Operations - NCL Timely Reporting

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total	61.8%	64.3%	63.1%	69.5%	74.0%	77.7%	80.8%	75.5%	75.9%

Even with only a slight increase in 2021 compared to 2020, the focus on early reporting and prevention has contributed to the downward trend of injury severity and reduction in average cost per claim. While the total number of claims has increased since 2013, the majority are minor claims with fewer medical costs. We anticipate this downward injury trend will continue with increased timely reporting, IA utilization, Industrial Ergonomic evaluations, and Health and Wellness programs.

Industrial Athlete Specialist (IAS) Utilization – Increased focus on PG&E's IAS engagement and utilization in cities identified as having higher risks and exposures. IAS are trained physical therapists who focus on observing employee biomechanics, ergonomics and risk behaviors that result in identification of corrective actions and recommendations. In 2021, 39 percent of IAS Participation is within GO and focused the service type is preventative and through group interaction. 96.1 percent of coworkers with a resolved IAS Case did not have a new MSD related Worker's Compensation claim.

Industrial Ergonomics – Increased assessment of individual tasks by both Industrial Ergonomists and Field Safety Specialist through the utilization of Humantech and documented Ergonomic Observations. Leading to identification of risk and development of strategy for reducing discomfort and injury.

c. 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 leak survey, 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.

In 2021, the Gas Safety Academy also made significant capital improvements to the leak field by replacing valves and actuators and upgrading the command and control software improving reliability resulting in a more engaging learner experience.

Table 25 – PG&E Number of Courses Developed or Enhanced from 2012 through 2021

2021	118
2020	224
2019	112
2018	122
2017	162
2016	214
2015	107
2014	78
2013	88
2012	14
Total*	**1239**

* Total does not represent total # active courses.

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 2021, the Gas Safety Academy rose to meet the unique safety challenges presented by COVID-19 by implementing and exceeding the county, state and federal guidelines. For instance, to ensure the safety of participants, instructors and facility staff, a new facility entry screening process was implemented which requires each individual on campus to submit a health screening medical questionnaire utilizing the LiveSafe application, temperature checks before entry, and adherence to established COVID protocols such as wearing face coverings which resulted in zero COVID transmissions while attending classes at the facility. Additionally, the lunch distribution process was changed to provide prepackaged meals in individual containers with distribution by trained staff wearing gloves.

In 2021, GO trained approximately 21,500 student days at the technical, apprentice, and leadership levels. As of December 31, 2021, PG&E had developed or enhanced 1,239 courses since 2012 (Table 25). PG&E continues to enhance and continuously improve the training, so that all classifications in GO have initial and refresher training.

Highlights from 2021 include:

- The implementation of the Leading with Safety program, which reimagined the new hire training journey for Utility Gas Service Representatives and Gas Utility Representatives to begin with an emphasis on safety through a multi-day blended learning experience aimed at improving physical and mental resilience and preventing injuries and accidents during their work activities;
- Driver training led by internal GO employees who are certified Smith Driving Instructors, now utilize employee assigned vehicles when available and vehicle related driving scenarios as part of the instructional strategy;
- The M&C flow lab valves received an update as an ongoing approach to upgrade equipment to ensure alignment with changes in the industry;
- Designed, established and implemented the Safe Access field to support the Compliance Department's L&M Training. Using an integrated holistic approach, this has enabled employees to safety locate electric facilities; and
- In response to overpressure events, the Academy worked with GO to make significant improvements to Gas Clearance training for identified Gas Pipeline and Operations Maintenance employees.

The Gas Safety Academy made significant improvements in 2021 to technologies used to facilitate learning including the Pilot deployment of augmented (mixed) reality through the HoloLens initiative along with digital tailboards. Mobile MyLearning was expanded to more courses allowing learners the ability to complete safety and compliance training on company smart devices without needing to travel to a headquarters. In addition to being a COVID-safe option, Mobile MyLearning provides the opportunity for on demand training and immediate content updates in the field. Furthermore, the Gas Safety Academy went paperless by converting class reference books to a digital format. A digital format allows notetaking on classroom iPads using Smart Mobile Workforce (SMW), learner access to classroom materials outside the classroom through SMW, material updates for learners after attending class, and a reduction in cost through the elimination of printed classroom materials.

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 26 are the output of a partnership between the LOB, SMEs, and PG&E Academy. The partnership starts with Gas Training Governance and is led by leaders within GO to ensure that PG&E Academy's projects are aligned to key initiatives and high-risk, high consequence tasks 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 its policies and processes that successfully supports PG&E GOs' strategic objectives to deliver to our hometowns, serve our planet, and lead with love.

Table 26 – Gas Operations Training Recommendations 2012-2021

2012 Recommendation	Progress as of Dec 31, 2021
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 for most functional areas in Gas Ops. • A Virtual Learning (VL) studio was commissioned and placed in service at the Gas Safety Academy in Winters. Additional topic areas were taught as VL in 2019 – which reduces non-productive time and travel costs and increases consistency and quality of procedural updates and training. Technologies deployed in home office setting enabling multiple session remote VL training facilitation during COVID.
Implement continuous training improvement processes	• GO Training Governance Committee continues to mature thorough an enhanced governance process to review and approve all major redesigned and new curriculum and training requirements. The Academy partnered with the LOB and the Gas Qualifications department to develop technical training and qualification profiles for GO 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.

d. Gas Operator Qualifications

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

Figure 51 – Employees Taking Written Operator Qualification Exam (Photo Captured Pre COVID-19).

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.

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

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

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

In 2020, PG&E implemented a program to ensure process consistency with approved contract evaluator and proctors. The program includes regular visits by a PG&E OQ representative to the approved contract evaluator and/or proctors' location to conduct an observation of their OQ process during a live OQ evaluation. This is to ensure the vast number of approved contract evaluators programs are consistent with PG&E's internal OQ program and to provide feedback or opportunities for improvement when necessary. The Gas Qualification department refined the program last year.

In 2021, PG&E allowed the use of an interpreter to verbally translate three OQ exams into Spanish for employees whose primary language is Spanish.

- 0212 – Install Pipe in Bore;
- 0215 – Installation, Backfill, Compacting; and
- 0507 – Damage Prevention During Excavation.

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.

e. CONTRACTOR SAFETY AND OVERSIGHT

Contractors are an important aspect of PG&E's technical workforce. Since contractors often work with PG&E's assets and infrastructure that directly impact employee and public safety, the Company holds contractors to the same standard of safety as PG&E employees. The CPUC's Safety Culture OII proceeding (I.15-08-019) included a report that evaluated PG&E's safety practices, including those in GO. The report recommended that the GO 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 52) for contractor safety and oversight. Other revisions included updates to various responsibilities (Competent Site Representatives and Project Team), enhanced the contractor safety observation criteria, and added requirements for PG&E Safety Representative.

Figure 52 – Four-Step Process to Contractor Safety and Oversight

Prior to starting a job, PG&E *pre-qualifies* contractors and subcontractors, and confirms they are qualified to complete the contracted work through internal and third-party (ISN) reviews. PG&E continues to improve its contractor pre-qualification process and update 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.

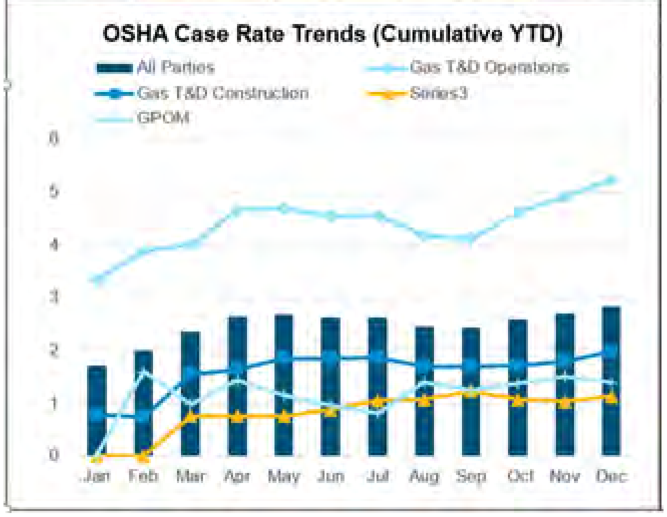
Once construction on a project has started, PG&E carries out a *plan* for contractor performance and clearly communicates contract terms that hold contractors accountable for safety and quality. Job-site observations start during pre-job walk-throughs to evaluate site specific hazards prior to starting 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 Quality Assurance (QA) team randomly checks project completion from beginning to end. On a quarterly basis, PG&E's leadership and contractor leadership meet to understand opportunities to improve the overall Contractor Safety and Oversight Program, 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. Figure 53 provides 2021 metrics on injuries and motor vehicle incidents. Note that in 2021, PG&E Contractors outperformed in all performance metrics when compared to PG&E as a whole. Contractors worked over 3.4 million hours performing high risk work.

OSHA				
All Parties	T&D Operations	T&D Construction	GPOM	Contract Partners
2021 EOY				
2.84	5.23	1.97	1.39	1.12
Gas Operations EOY OSHA Target: N/A				
2020 EOY				
2.70	5.01	1.93	2.69	0.22
Quartile Ranking YTD*				
N/A	4th	3rd	3rd	N/A



PMVI				
All Parties	T&D Operations	T&D Construction	GPOM	Contract Partners
2021 EOY				
1.70	2.93	2.14	1.02	0.38
Gas Operations EOY PMVI Target: 1.91				
2020 EOY				
1.67	2.50	1.60	3.08	0.23
Quartile Ranking YTD*				
N/A	2nd	2nd	1st	N/A

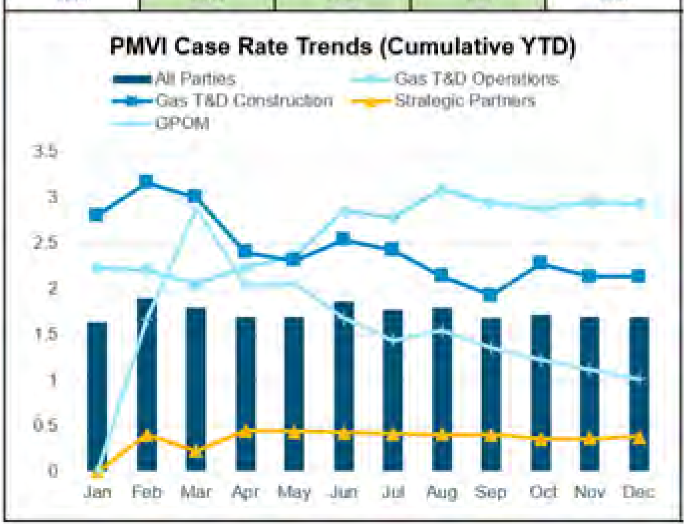


Figure 53 – 2021 Gas Safety Performance

In 2021, Gas Contractor Safety Team and GO Contract Owners focused 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 noted count and rate increases in comparison to previous years. The increases in reporting resulted in the following 50 percent Increase in First Aid Only incidents, 61 percent increase in PMVIs, 76 percent Increase in OSHAs, 48 percent increase in Good Catches. Looking into 2022, Gas Contractor Safety expects to continue to see rigorous and expanded reporting by our Contract partners. With the noted increases in Figure 54, the Gas Contractors continue to outperform in comparison to the PG&E workforce. GO 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.

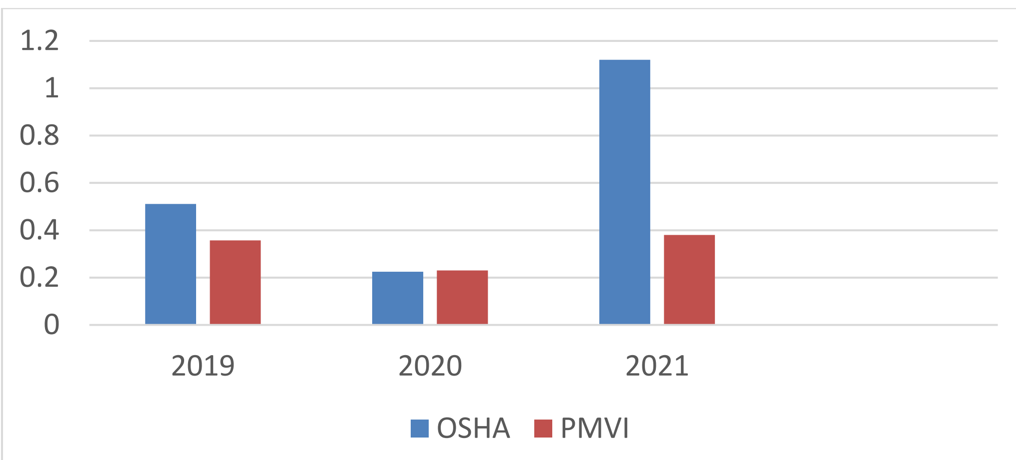


Figure 54 – Strategic Partner Safety Year Over Year Performance

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

As PG&E strives to improve project safety, quality and productivity, the Company takes every opportunity to 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 2021, there were

991 “Good Catches” turned in to PG&E’s safety and construction management function. This is a 48 percent increase compared to 2020, which is a direct result of operational impacts from COVID-19. 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

f. Partnership With Labor Unions

Union-represented employees make up almost 73 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 2021, PG&E continued to collaborate with union leadership on projects such as improving emergency response and “make safe” times for blowing gas situations, overpressure events, enhanced lines of progression, Estimator in Training Program, Grassroots Safety Committee Partnership, and PG&E’s Leak Survey Optimization Program.

The line of progression effort has updated job duties, training, and certification for almost every represented field-based position. These changes have driven improved training and certifications for the Company’s workforce (Power Pathway Gas Pre-Inspectors for example), improving the safe and compliant delivery of service.

VI. Compliance Framework

PG&E transports and stores NG under the requirements of state and federal safety regulations. The Compliance and Ethics Maturity Model was developed in 2016, 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 compliance and ethics program. In 2017, PG&E’s Executive Guidance stated that each LOB is to achieve Level 3 maturity in each of the 8 Maturity Model elements

The Compliance Maturity Model (CMM) consists of eight elements (as shown in Figure 55), each element is assessed and assigned a maturity level rating:

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

Since 2018, annual validations have been performed by Ethics & Compliance (E&C) in partnership with PWC, to assess each LOB’s compliance maturity level. Figure 55 below shows the framework's eight elements and Gas Organization's maturity level for each of these elements at the end of 2020. 2021 compliance maturity scores currently aren't available at the time of writing.

Figure 55 – Gas Operations Compliance Maturity Scores by Element

CMM is a framework to manage the overall compliance program, it provides the Gas Organization a guideline on what an effective E&C 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.

In 2016, a baseline performance assessment was conducted, and in 2017 the business began the work of aligning federal and state regulatory requirements to our processes and conducted annual PwC third-party assessments on the 8 elements of the CMM. In 2019, although Gas Organization did not achieve an overall level three for its CMM, gaps were identified in all eight elements of the program. In 2020, GO organization developed a remediation plan to address these gaps, which included assessment and update of regulatory requirements inventory to ensure it was accurate and complete, and strengthening programmatic and process controls to manage compliance with current and future regulations. As a result, GO organization made significant progress in advancing to the next maturity level for five of the eight elements and achieving Level 3 maturity for three elements during the year-end assessment.

Gas Operations Organization carried 2020's momentum and success into 2021, completing all action items listed in the 2020 remediation plan and developed a 2021 remediation plan to address observations from 2020 PwC third-party assessment. The Gas Operations Organization Controls Program was established in 2021, the program focused on update and documentation of key controls for high and medium-risk regulatory requirements. Documented controls were published to

MetricStream, PG&E's enterprise compliance management tool. Another major effort accomplished in 2021 was in the guidance document area. Standards Engineering team completed mapping of guidance documents to all regulatory requirements, ensuring guidance and procedures are in place to comply to regulatory requirements. These highlighted accomplishments and completion of action items in the 2021 remediation plan are expected to improve maturity scores in all 8 elements in the CMM. PG&E did not utilize PwC for the 2021 assessment in order to allow the LOB more time to focus on remediation work. In lieu of PwC assessment, Gas Organization, in partnership with E&C, is conducting a 2021 self-assessment to measure maturity levels to see if they have been sustained or improved. Self-assessment scores are expected to be finalized in Q1 2022 and presented to leadership. A 2022 remediation plan will be developed to address gaps identified in the self-assessment.

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

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

a. Building Expertise

PG&E employees require specialized skills to be able to perform their jobs constructing, operating and maintaining the NG 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 CI.

b. The Right Information to Do the Work

A highly-skilled workforce is most effective when enabled with timely, accurate information from which to work. Gas pipeline work is highly technical and, if not performed correctly, could result in serious safety concerns. In order to enable the consistent performance of work across our service territory PG&E utilizes 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 on a routine basis so that that they reflect both regulatory requirements and best practices, as well as any lessons learned from Company or industry experiences. 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 also requires significant efforts to keep all personnel performing work in accordance with these documents ensuring that they are made aware of any changes, and 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. Email communications are sent out that separates changes based on several categories, allowing employees to more efficiently determine relevant changes. 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 to name a few.

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 to effectively conduct IM program work, locate mains and services, and plan for construction. PG&E works continuously to improve the quality of the information in both mapping systems. Given the volume of work performed on the pipeline systems every day, it is critical to have processes that update these mapping systems accurately, and in a timely manner. As prescribed in the CMM, compliance goals need to be accompanied by effective controls and performance monitoring.

c. The Right Resources to Do the Job

Once the correct work has been identified, PG&E determines the number of internal and external resources needed to complete the portfolio of work efficiently. PG&E maintains agreements with multiple contractors and maintains a database of construction qualifications in order to assign work to the appropriate and most efficient resources. PG&E utilizes workplans comparing anticipated level of effort, including emergent work forecasts, to internal resource capacity, in order to signal the need for additional overtime, contractor resources, etc.

d. 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 CI or pending regulatory changes. Table 27 below details some of these processes and programs.

Table 27 – Compliance Processes and Programs
Quality Management (QM) – The QM group assesses and provides direct feedback on the work quality for PG&E's important safety programs, including L&M, regulator station maintenance, and as-built record development. [See Section VII.2 *Quality Management*].
Internal Audit (IA) – PG&E's IA team performs arm's length reviews for all the Company's LOB, including GO, and is responsible for assessing control adequacy.
Non-compliance Self-Reporting – PG&E is committed to self-reporting compliance issues and taking prompt mitigative and corrective action. Each issue that is self-reported receives a work group evaluation to enable employees to learn from the issues and prevent reoccurrence.
Participation in Safety and Enforcement Division (SED) Inspections – In advance of CPUC SED inspections, PG&E self-evaluates gas divisions, districts and programs, such as OQ, Emergency Management and IM, and shares findings with the SED. PG&E's assessors spent approximately 11,000 hours in 2021 managing data response issues and supporting resolution. PG&E strives to resolve identified issues within the same inspection cycle and respond to any data requests within the duration of the inspection.
Cause Evaluation – Similar to the CI mechanism in PG&E's Process Safety management framework, cause evaluations are post-incident investigations that include an incident analysis and recommendations to prevent or mitigate future reoccurrence. Cause evaluations are conducted based on business determination of identified issues.
Evaluation of NTSB Reports – The NTSB investigates all serious pipeline incidents. PG&E SMEs routinely review NTSB reports to learn from pipeline incidents. As a result, PG&E may adopt new approaches to addressing threats, change work procedures or develop new training.
Evaluation of PHMSA Bulletins – PHMSA regularly issues safety advisories for pipeline operators. As new safety information comes to light at other gas companies in the US, PHMSA issues bulletins to help operators take preventative action.

Since 2019, GO has developed a Compliance Action Plan by 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 POs and Process Managers (PM) in developing specific action items to address these top challenges. As a result of making data-driven decisions, GO made significant improvements in our compliance performance, reducing non-conformance by 80 percent in 2019 and another 40 percent in 2020.

Starting in 2020, the Regulatory Compliance team advanced our CI efforts by partnering with the QM team. For the first time, the two teams performed a cross-functional data analysis to identify improvement opportunities in our QA process. As a result, GO created new QA programs and is working with POs and PMs to implement additional controls in their processes to prevent non-conformances. All these efforts have allowed GO to maintain similar compliance performance when compared to 2020.

VII. Continuous Improvement

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

a. LEAN CAPABILITY CENTER

The Lean Capability Center (LCC) is an organization developed within GO to execute and deploy Lean Management as our fundamental way of working. GO is committed to maturing the Lean Management system by continuing to engage and empower employees at all levels in direct support of our GSEMS to:

- Break down silos;
- Simplify processes and reduce waste;
- Eliminate rework and reduce cycle times;
- Maintain focus on hand-offs;
- Improve end-to-end process performance;
- Make meaningful improvements that create efficient and engaging work; and
- Recognize good work and celebrate successes.

Figure 56 – Lean Management System in Gas Operations

The LCC provides strategic direction for Lean journey and empowers CI. The LCC partners with functional and Process teams to solve issues and identify better ways of working. We are focused on creating workflow that continuously improves our work performance, creates greater transparency around the work plan and empower employees to better execute their role. This creates a culture of

CI that directly supports Gas Organization goals around safety, reliability, affordability, and sustainability.

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

<u>LCC Service Offerings</u>

- Process Management:

  Process Management involves planning, monitoring, and controlling the performance of a business process with the goal of meeting customer and business requirements. As such, Process Management promotes safety, reduces costs, increases quality and efficiency, and ensures controls are in place.

- Process Improvement:

  Process improvement is working with process management leads to improve, enhance, and mature their end-to-end processes.

In 2021, the LCC implemented the Continuous Improvement Initiative Management System, which is a tool to manage and track improvement initiatives. A few of the improvement initiatives in 2021 include advancements in process management, safety, reliability, and affordability.

<u>LCC Focus in 2021</u>

- January 2021 marked the 8th year of our Lean Journey in GO. With this milestone, we see the positive impact of our employees speaking up, sharing ideas, solving problems, and implementing improved ways of working. learning how to think differently to work safely and efficiently;
- Advance Process Architecture to improve end-to-end process accountability, establish standards, improve hand-offhand-offs, and increase PO involvement in Rate Case development and CMM;
- Continue to mature our processes;
- Support the E&C's CMM initiative to enhance rigor in our control plan and controls testing for processes with code requirements; and
- Increase collaboration among teams across the organization.

  By assisting in these areas, we will continue to:
- Achieve better alignment through strategic thinking and goal setting;

- Empower employees to articulate how their work contributes to the organization's goals and focus efforts on the most important work;
- Enable GO organization to more effectively control the interactions and interdependencies of processes to enhance and improve overall performance; and
- Our support of these efforts will help build a strong safety culture, enhancing public, workforce, and environmental safety.

b. Quality Management

Gas QM is comprised of QA at the GO level and QC situated 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 along with Compliance under the Quality Management System (QMS) umbrella are working together to drive down noncompliance risks. The following illustration depicts the layers of defense working to mitigate noncompliance risk.

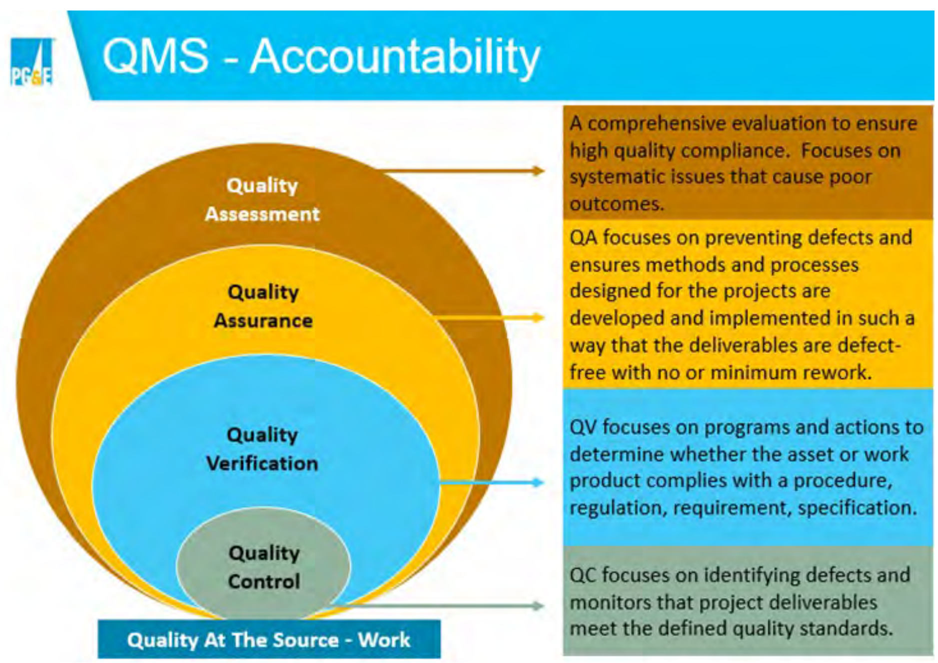


Figure 57 – Layers of Defense Against Noncompliance Risk

The QMS framework and collaborative approach to quality allows for CI and drives consistency by identifying nonconformances, recommending corrective actions and following up with mentoring and coaching people doing the work. It also continues to be in alignment with the fundamental principles of the QMS which leverages the “PDCA” framework (Figure 58 below). PDCA being the iterative four-step management method used in business for the control and CI of processes and products. Just as a circle has no end, the PDCA cycle should be repeated for CI.

Figure 58 – QMS Fundamental Principles

In 2021 T&D construction, regulator stations and valves, and As-Built job packages continued to be reviewed by QC and QA. GO shifted field based QC to local leadership for L&M, leak survey and corrosion field work. Field Service field based QC and QA assessments remained unchanged. There were 19 active QC/QA programs as of December 2021, shown in Table 28 below.

Table 28 – List of Quality Management Programs as of 2021	
Leak Survey T&D	Odorization
Locate and Mark	Distribution Construction
Field Service	Transmission Construction
Valve Maintenance	Regulator Station Maintenance
Corrosion Control	Dual Assets
Internal Records Review	GT&D As-Builts
Chain of Custody	Post Construction Asset Validation
QA Pipeline Features List (PFL)	GT Alignment
Scanning & Attributing	Instrument Calibration
GD-GIS	

In keeping with our QMS maturity journey and expansion of our quality oversight we also accomplished the following in 2021:

- Conducted 15 targeted process audits;
- Performed safety culture audit of construction crews;

- Enabled construction quality specialists to conduct dual asset assessments;
- Added side by side field based assessments in Leak Survey and L&M programs
- Increased American Society for Quality Certified Quality Improvement Associate certifications by four percent;
- Performed 2,490 quality assessments in the field and 5,241 records reviews;
- Developed new protocols to assess transmission leak survey aerial patrols records and canceled leaks for QC; and
- Created weekly and monthly dashboards for each process to share performance and trends related to quality assessments.

In 2021, quality performance across GO was 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 shift in 2021 was to drive corrective actions for all nonconformances versus 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 nonconformance.

Gas Operations Quality Assurance Target - FIELD			
2021 YTD Findings - Overall QA Targets			
High	Total Findings	Total Checked	Average Error Rate
34	580	69,856	0.830%

Gas Operations Quality Assurance Target - RECORDS			
2021 YTD Findings - Overall QA Targets			
High	Total Findings	Total Checked	Average Error Rate
7	796	79,064	1.007%

Figure 59 – 2021 QA Field Performance Metric

c. 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 2021 DPPM performance was 286 against the target of 325. For 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, QMS and other technically quality parameters which will aid PG&E in reducing risk with more targeted quality efforts.

SQA achieved significant performance since 2013 for quality programs driving supplied material to an ultimate goal of being defect free. 85 percent of gas high risk suppliers are ISO certified SQA was re-certified to ISO 9001:2015 QMS in 2021 and had zero non-conformities for all audits. Through PG&E’s cross functional teams and supplier partners, SQA processed 132 supplier change requests in 2021 and seven supplier material recalls (36 percent improvement from 2020). In addition, SQA conducts an annual supplier survey to identify improvement opportunities.

d. Research and Development and innovation

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

R&D and Innovation is embedded within GO through Gas Safety Excellence and the CI process. R&D and Innovation’s work is prioritized based on the results of the Risk Management Process, so projects and innovations align with the most critical needs of the business [see Section IV.3. *Risk Management Process*]. R&D and Innovation projects and their results are directly included within each Asset Family Safety Plan to assure that new technologies and methods are effectively leveraged to improve the safety, reliability and cost effectiveness of PGE’s assets. Its scope includes not only NG but also new fuels such as bio-methane and hydrogen in order to support the decarbonization of the gas system towards carbon neutral energy delivery by 2045.

In 2021, the R&D and Innovation team has managed and implemented a broad portfolio of more than 200 active projects covering seven priorities in collaboration with leading U.S. and overseas utilities, pipeline operators and R&D organizations:

- Understanding the conditions of our assets focusing on inspection techniques including In Line Inspection, Non-Destructive Examination for steel and plastic pipelines;
- Extending the safe operational life of our assets, addressing corrosion and ground movement issues;
- Developing proactive operations through new data collection and processing methods and technologies;
- Reinventing leak management including methane emission abatement;
- Preventing dig-ins by improving asset localization, introducing new excavation management methods and developing new underground asset detection technologies;
- Improving construction method with an emphasis on ergonomics and personal safety; and
- Decarbonizing California's energy system through new fuels including Renewable NG, Biomethane and hydrogen.

PG&E also uses the Center for Gas Safety and Innovation in Dublin, California. Opened in 2017, 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 participates in collaborative efforts with national and international R&D organizations such as PRCI, NYSEARCH, Operations Technology Development and Utilization Technology Development. PG&E also works closely with R&D programs at the California Energy Commission, PHMSA, the CARB, the Department of Energy and multiple universities including Stanford (through the NG 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 GO in the most effective way:

Examples of 2021 achievements include:

- Field testing of a new in-line mercaptan sensor that can quantify odorization compounds of a NG flow in real time down to their detectability level, in parts per billion. This work initiated in 2015 with NYSEARCH and UC Davis has been associated with testing at the Monell laboratory in Philadelphia to establish proven detectability thresholds that can be reliably verified in the field (Fig.60);
- Use of methane/ethane detector mounted on an Unmanned Aerial Vehicle to survey pipelines at water crossing in replacement of traditional methods on boats or by foot along the pipeline

spans that are less effective and may expose operators to higher safety risks. Two successful demonstrations were performed with simulated leaks in Topock and Delta Waterway. The methane/ethane detector is the results of R&D efforts led with NYSEARCH, PRCI and NASA/JPL leveraging the technology developed to detect methane on Mars. Its light weight, small form factor, low power demand and superior sensitivity makes it ideal for small drones (Fig.61);

- Installation of three sets of distributed fiber optical sensors in a production well at the Mac Donald Island storage facility to assess and compare the technologies developed by Schlumberger, Lawrence Berkeley National Laboratory and Paulsson to monitor the well integrity (temperature, vibration, strain). The field demonstration funded by the California Energy Commission is supplemented by laboratory tests performed by the C-FER technology in Edmonton (Canada). In addition, a novel Electromagnetic Guided Wave system is tested for monitoring of the well surface casing integrity without insertion in the well. The program also includes a project in collaboration with PRCI and PHMSA to assess and improve the performance of thru-tubing metal thickness probes (Fig.62); and
- Launch of the Hydrogen Living Lab that will demonstrate and study the impact of hydrogen on distribution pipelines and develop mitigation measures. The project is a broad collaboration of North American utilities through the NYSEARCH consortium offering a very cost-effective approach that will also facilitate a shared experience across the industry. The facility will be operated by SoCalGas with an easy access for PG&E.

Figure 60 - Test of the novel Mercaptan sensor by UC Davis at PG&E Academy's Winters facility

Figure 61 - Water crossing leak survey using an Unmanned Aerial System

Figure 62 - Installation of Optical Fiber Sensors in a storage well

e. BENCHMARKING AND BEST PRACTICES

Benchmarking is an important step in PG&E's overall CI effort and is used to identify industry best practices. Best practices include, but are not limited to, widely recognized NG 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.

i. Industry Standards Written by Subject Matter Experts

One informal benchmarking practice that PG&E pursues is identification and use of standards written and reviewed by SMEs. Sometimes these standards are referred to as "consensus" standards, meaning that the publisher believes that they represent proven practices in that particular field. In addition to seeking best practice standards that originate in the U.S., PG&E identifies international standards for best practices, including European and ISO. PG&E has adopted for use several European standards. In another example, PG&E pursued the certification of ISO 55001, the international asset management standard, and has both achieved and sustained certification.

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

ii. 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.

iii. 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.

iv. American Gas Association

As part of PG&E's CI commitment to safety in GO, the Company is an active member of the AGA. The AGA helps PG&E share, validate and learn about gas safety best practices through targeted Operating Committees and Discussion groups with peer organizations. For example, PG&E participates in the AGA SOS Survey Program by both distributing and responding to surveys with topic-specific information requests throughout the year and utilizes the data provided by other U.S. utility gas companies.

v. Interstate Natural Gas Association of America

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

vi. NACE International

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

vii. Western Energy Institute

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

viii. Public Service Enterprise Group

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

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

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

ix. Additional Benchmarking Efforts

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

PG&E also uses benchmarking to facilitate CI. 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 29 – Key Benchmarking Metrics

PG&E's Commitment to Safety	Measurement
Emergency Odor Response	Average response time
Year-End Grade 2 Leak Backlog	Per 1,000 miles of mains and services
Year-End Grade 3 Leak Backlog	Per 1,000 miles of mains and services
Lost Work Day Case Rate [(a)]	LWD per 200,00 hours worked
Total Dig-in Reduction1	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

(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 2022 Plan update demonstrates PG&E's commitment and progress in implementing processes, programs, and procedures to achieve its stance of keeping everything and everyone safe. The GSEMS guides how PG&E operates, conducts, and manages all parts of its business by putting the safety of the public, PG&E's customers, and PG&E's employees and contractors at the center of its work; investing in the reliability and integrity of its gas system; and, by continuously improving the effectiveness and affordability of its processes. PG&E has made continued progress, but recognizes that there is more to be done in its journey to Gas Safety Excellence.

IX. ENDNOTES

1 See Attachment 1 for a Table of Concordance that provides a mapping between the Pub. Util. 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 Pub. Util. Code §§ 961 and 963(b)(3).

3 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.

4 In 2017, a Federal Court-Appointed Monitor was assigned to PG&E to oversee PG&E's safety performance for the period of PG&E's court-ordered probation stemming from its conviction in connection with the San Bruno incident and resulting NTSB investigation. The Monitorship ended January 25, 2022.

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. Tier A is the most lagging and Tier D is the most leading.

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

9 See PG&E's 2020-02 Gas Transmission & Storage Safety Report (submitted on May 17, 2021) and PG&E's 2020 Gas Distribution Pipeline Safety Report (originally submitted on March 31, 2021).

10 American Petroleum Institute (API) RPs 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 RPs 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 The Transmission Pipe asset family includes valves 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.

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

14 The strategic objective of the Public Safety Risk Council is to develop and monitor the strategic planning and execution of risk management by providing independent review and challenge of key

risks, ensuring executive leadership knowledge of all key risks, and driving risk management best practices consistently across the Enterprise.

15 49 CFR §192.614.

16 CGC §4216.

17 I.18-12-007 Order Instituting Investigation and Order to Show Cause on the Commission's Own Motion into the Operations and Practices of PG&E with Respect to L&M Practices and Related Matters.

18 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.

19 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.

20 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.

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

22 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.

23 215 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. https://www.dshs.texas.gov/news/updates/SMOC_FebWinterStorm_MortalitySurvReport_12-30-21.pdf

24 PG&E's California Gas Transmission Pipe Ranger website Supply and Demand Archives, https://www.pge.com/pipeline/operations/cgt_supplydemand_search.page. Execute search for December 31, 2021 and preceding 366 days, then add values listed in "Total System Supply" row.

25 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."

I. Appendix A – List of Figures

II. Appendix B – List of Tables

III. Appendix C – List of Attachments

Attachment 1 – Table of Concordance

Attachment 2 – 2022 – 2023 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 – Gas Manual: TD-4870M, Gas Storage Asset Management

Attachment 5 – Utility Standard: TD-4880S Facility Integrity Management Program

Attachment 6 – Utility Procedure: TD-4125P-10 Identifying Gas Transmission Assets

Attachment 7 – Change Log for 2022 Gas Safety Plan

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 1

TABLE OF CONCORDANCE

2022 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 2022 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 2022 Gas Safety Plan provides a view into the safety activities PG&E pursues every day and highlights the specific safety work performed in 2021.
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. iv. 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. 7. a. Gas Systems Operations and Control VII. 2. Quality Management

PUC Section	Section Location(s) in Gas Safety Plan
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. iii. Locate and Mark Program IV. 5. a. iv. 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 V. 3. Workforce Training V. 4. Gas Operator Qualifications V. 5. Contractor Safety and Oversight

PUC Section	Section Location(s) in Gas Safety Plan
	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 corporation workforce to carry out the plan.	V. Workforce
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	II. Safety Culture

PUC Section	Section Location(s) in Gas Safety Plan
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.	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 2021. 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

2022 LEAK ABATEMENT COMPLIANCE PLAN

PACIFIC GAS AND ELECTRIC COMPANY'S 2022 LEAK ABATEMENT COMPLIANCE PLAN MARCH 15, 2022

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 a sustainable energy future. Consistent with our vision, 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 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 2022 Leak Abatement Compliance Plan (2022 Compliance Plan) is the third biennial Leak Abatement Compliance Plan prepared in accordance with the Commission's decision and covers the years 2022-2023.

PG&E has made strides in reducing the methane emissions of its systems through the execution of its first two 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 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

There are current limitations on reaching the reduction targets due to those emissions that are population-based (e.g., meter sets, regulator stations, etc.). PG&E will work with the CPUC, the California Air Resources Board (CARB), and other stakeholders to develop new reporting methods that represent the actual emissions.

By 2025, PG&E anticipates meeting the 20 percent reduction goal through the following activities:

- Optimized leak survey
- Potential reduction of the Super Emitter (SE) threshold
- Extending blowdown reduction strategies to compressor station and storage facilities
- Lowering the pipeline pressure to near zero for scheduled backbone transmission projects
- Applying degassing technologies for In-Line Inspection (ILI) and lower volume transmission projects

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

- 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, monitor D).
- Extending blowdown reduction strategies to more system categories.

Table 1 compares the 2015 baseline emissions with the 2020 reported emissions, as reported in PG&E's 2020 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 2021 emissions are unavailable and will be submitted on June 15, 2022 in PG&E's Natural Gas Leak Abatement Annual Report.

Table 1. 2015 Baseline vs. Reporting Year (RY) 2020 Emissions, including Supporting Best Practices

System Categories	Emission Source Categories	Fugitive or Vented	For Reference Only: 2015 Baseline Emissions (Mscf)	2020 Total Annual Volume of Leaks & Emissions (Mscf)	Percentage Change for Year Over Year Comparison from 2015 to 2020	Best Practice Support Emissions Reduction
Transmission Pipelines	Pipeline Leaks	Fugitive	3,701	3,709	0.2%	BP 17 - Enhanced Methane Detection BP 19 - Aboveground Leak Surveys BP 21 - Find It/Fix It

	All Damages	Fugitive	81,793	4,022	(95.1%)	BP 24 - Dig-Ins / Public Education Program BP 25 - Dig-Ins / Company Standby Monitors BP 26 - Dig-Ins / Repeat Offenders
	Blowdowns	Vented	251,227	128,670	(48.8%)	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	27,518	499.4%	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Leaks	Fugitive	--	N/A	-	n/a
	Odorizers	Vented	135	194	44.4%	n/a
Transmission M&R Stations	Station Leaks & Emissions	Fugitive	579,240	547,290	(5.5%)	n/a
	Blowdowns	Vented	65,456	68,293	4.3%	n/a
Transmission Compressor Stations	Compressor Emissions	Vented	70,186	19,342	(72.4%)	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Compressor Leaks	Fugitive	--	0	-	n/a
	Blowdowns	Vented	19,864	37,083	86.7%	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	--	18,448	-	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities

	Component Leaks	Fugitive	15,823	11,356	(28.2%)	BP 17 - Enhanced Methane Detection BP 19 - Aboveground Leak Surveys BP 21 - Find It/Fix It
	Storage Tank Leaks & Emissions	Vented	N/A	298	-	BP 17 - Enhanced Methane Detection BP 19 - Aboveground Leak Surveys BP 21 - Find It/Fix It
Distribution Main & Service Pipelines	Pipeline Leaks	Fugitive	626,590	502,727	(19.8%)	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	39,685	(72.9%)	BP 24 - Dig-Ins / Public Education Program BP 25 - Dig-Ins / Company Standby Monitors BP 26 - Dig-Ins / Repeat Offenders
	Blowdowns	Vented	141	169	19.6%	n/a
	Component Emissions	Vented	N/A	N/A	-	n/a
	Component Leaks	Fugitive	N/A	N/A	-	n/a
Distribution M&R Stations	Station Leaks & Emissions - Leak-Based	Fugitive	9,440	9,440	0.0%	n/a
	Station Leaks & Emissions - Population-Based	Fugitive	741,986	883,459	19.1%	BP 17 - Enhanced Methane Detection BP 19 - Aboveground Leak Surveys BP 21 - Find It/Fix It
	All Damages	Fugitive	--	–	-	n/a
	Blowdowns	Vented	147	263	78.8%	n/a
Customer Meters	Meter Leaks - Leak-Based	Fugitive	245,907	245,907	0.0%	BP 22 - Pipe Fitting Specifications
	Meter Leaks - Population-Based	Fugitive	636,034	650,385	2.3%	BP 17 - Enhanced Methane Detection BP 19 - Aboveground Leak Surveys BP 21 - Find It/Fix It
	All Damages	Fugitive	--	4,545	-	BP 24 - Dig-Ins / Public Education Program BP 25 - Dig-Ins / Company Standby Monitors BP 26 - Dig-Ins / Repeat Offenders

	Vented Emissions	Vented	231	155	(32.8%)	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
Underground Storage	Storage Leaks & Emissions	Fugitive	11,870	2,584	(78.2%)	BP 17 - Enhanced Methane Detection BP 19 - Aboveground Leak Surveys BP 21 - Find It/Fix It
	Compressor Emissions	Vented	5,360	4,681	(12.7%)	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Compressor Leaks	Fugitive	--	–	-	n/a
	Blowdowns	Vented	16,324	10,973	(32.8%)	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	--	77,795	-	
	Component Leaks	Fugitive	10,574	2,222	(79.0%)	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Dehydrator Vent Emissions	Fugitive	6,761	13	(99.8%)	n/a
Unusual Large Leaks			N/A	0	-	-

Table 2. Total Emissions comparing 2015 & Adjusted Baseline with RY 2020 Emissions

2015 Baseline Emissions (Mscf)	3,294,368
Population based approach for Distribution M&R and Meter Set (Mscf)	3,045,879
Year Over Year Comparison with 2015 Baseline	**(7.5%)**
Adjusted 2015 Baseline (Mscf)	2,171,695
Leak-based approach for Distribution M&R and Meter Set (Mscf)	1,767,382
Year Over Year Comparison with Adjusted Baseline	**(18.6%)**

Table 2 above shows the 2015 Baseline Emissions vs. the RY 2020 with the population-based approach for Distribution M&R Stations and Meter Sets. The year-over-year (YOY) comparison with 2015 baseline has a reduction of 7.5%. The table also includes the adjusted baseline, where the RY 2020 Emissions for the Distribution M&R station and meter set leak-based approaches are taken as the baseline value. The YOY comparison with the adjusted baseline shows a reduction of 18.6%.

Based on the 2021 Joint Report[1], 68% of the total emissions are population-based. In the previous 2020 Compliance Plan, PG&E expected to accomplish a 17% reduction by 2021. This reduction is based on adjusting the baseline for meter set assemblies and distribution M&R stations from a population-based EF to a leak-based approach. Since this was not factored into the 2021 Joint Report, PG&E reported a much lower reduction of 7.5%. In order to meet our emission reduction goals, the baseline needs to be updated such that we can show progress with actual emission reduction efforts. This includes applying methane abatement strategies for transmission projects, the leak-based approach, and prioritizing leak repair based on the size of emissions.

Table 3 portrays estimated emission levels by measure in 2025 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.

[1] CPUC "Analysis of the Gas Companies' June 15, 2021 Natural Gas Leal and Emission Reports" January 21, 2022 p.6-7

Table 3. Emissions Level Estimate, MSCF, Year End

					Cost Effectiveness Part 5b $/MSCF				
Measure (Chapter No.)	**2025**	**2025 % Reduc.**	**2030**	**2030 % Reduc.**	**Cost Effectiveness Calc ($/MCF)**	**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)	263,549	8%	353,160	11%	$25	$23	$21	$2	Project Manager Guidance
					$7	$4	$3	-	Based on 2020 Cross Compression Activities
2) Gas Distribution Leak Surveys (Chapter 7) - Accelerated Leak Survey	not provided, this is dependent on the repairs				$44	$42	$41	$21	Based on 2016 5 year leak survey cost and 2020 forecast for 3 year leak survey cost
3) Find It /Fix It (Chapter 11) - Distribution M&S	230,606	7%	296,493	9%	$27	$25	$24	$4	SE Program with 10 scfh threshold, 123 SE leak repairs. Based on 2021 SE LS costs and average leak repair cost $7.5k/unit.
					$24	$22	$21	$1	SE program with 7 scfh treshold, assuming 500 SE leak repairs. Based on 2021 SE LS costs and average leak repair cost $7.5k/unit. As discussed further in Ch 11 of this Plan, PG&E is seeking approval of the option to lower the SE threshold from 10 to 7 scfh in 2023.
					$203	$201	$200	$180	2021 belowground grade 3 leak repairs. Based on 2021 belowground grade 3 leak repair data, average leak repair cost $7.5k/unit.
4) Find It /Fix It (Chapter 11) - Meter Set Assemblies	98,831	3%	197,662	6%	$40	$37	$36	$16	Based on 26% reduction estimate for prioritizing Class A and B Meter Set Leaks for repair.
5) Above Ground Leak Survey (Chapter 9) - Quarterly CARB Leak Surveys	16,472	0.5%	16,472	0.5%	$80	$78	$77	$57	Based on 2023 GRC Forecast and using 2017 adjusted (to account for 10k to 1k ppm threshold decrease) as the baseline.
6) Damage Prevention (Chapter 14)	varies depending on annual activities				$84	$82	$81	$61	Uses 2015 as the baseline and comparing against 2020 emissions for both Transmission and Distribution Damages.
7) Other - includes Improvement in reporting practices, studies to better characterize emissions, remove/replace emitting devices, etc.	49,416	2%	453,959	14%	TBD				Primary contributor for 2030 goal: R&D Projects (Chapter 15) - Transmission M&R Stations
TOTAL	658,874	20%	1,317,747	40%					

Each Chapter in this 2022 Compliance Plan describes a proposed Measure that consists of a Best Practice or a combination of Best Practices. The following is a table of concordance for Best Practices.

Table 4. Table of Concordance

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 Practice. Some Best Practices may be addressed by more than one Measure. Per guidance from the CPUC, each Chapter will detail the following information.

Part 1. Evaluate the Current Practices Addressed in this Chapter

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 2020 estimated reduction? What further reductions are expected?
    2. In terms of the utilities' own 2020 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?

Part 2. Proposed New or Continuing Measure

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 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, include the cost benefit of the proposed measure, by determining the ratio of net cost to all reasonably quantifiable benefits, where net cost is the average annual revenue requirement developed in Part 4.

Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when estimates have been determined. Do any incremental costs, if known, or benefits overlap with other measures? If so, describe.

a) Determine cost effectiveness as the ratio of net cost to volume of methane reduced, dollars per MSCF. Use the average annual revenue requirement from Part 4 divided by average annual emission reduction for as many time periods as represented by the average annual revenue requirement.

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

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

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.

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 2020 Compliance Plan as an attachment to its 2020 Gas Safety Plan on March 16, 2020. PG&E amended its plan on October 19, 2020, based on CPUC's feedback. The 2020 Compliance Plan summarized the actions taken in the 2020 Compliance Plan period (i.e., 2020 and 2021) 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 TBD by the company and approved by the CPUC, in consultation with CARB. Compliance Plans shall be signed by company officers certifying their company's compliance. Compliance Plans shall include copies of all policies and procedures related to their Compliance Plans. Compliance Plans shall be filed biennially (i.e., every other year) to evaluate best practices based on progress and effectiveness of Companies' natural gas leakage abatement and minimization of methane emissions.

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 2022 Compliance Plan period (i.e., 2022 and 2023). PG&E tracks completion of compliance plans in an internal tracking system to enable filing on a biennial basis. This 2022 Compliance Plan is submitted as a separate attachment to the 2022 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 November 15, 2019, PG&E updated its existing Climate Change Policy (ENV-03) to include a specific reference to minimizing methane, a potent greenhouse gas, and SB 1371 and SB 1383.

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 TBD 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 2022 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 2022 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 the new TD-5601 guidance documents; and
- The goals and requirements of new Greenhouse Gas (GHG) 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 project 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

TBD 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 TBD. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

Best Practice 5 – Methane Evacuation Procedure: Written company procedures implementing the BPs approved for use to evacuate methane for 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 TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

Best Practice 6 – Methane Evacuation Work 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 TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

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

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 2021, PG&E abated 84 percent of the total gas volume from transmission pipeline and regulator station projects (see Table 3 below).

Table 5. 2021 Transmission Pipeline and Regulator Station Abatement Activities

Pipeline Activity Type	Total Gas Volume (Mscf)
Drafting	99,756
Cross-Compression	666,686
Flaring	14,020
Bundling	20,949
Total Diverted (Drafting, Cross-Compression, Flaring)	801,411
Blowdown	150,613
% Abatement (Total Diverted/(Total Diverted + Blowdown)	84%

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 2022 Compliance Plan period and updates may be made pending results of post-blowdown evaluations that are conducted.

To further support Best Practice 23, in 2022 and 2023, PG&E plans to pursue the following to further reduce methane emissions from planned transmission blowdowns:

1. PG&E has purchased gas-driven mobile fill compressors and tube trailer, which allows PG&E to use mobile compression to target smaller blowdowns or pipelines that do not have a nearby pipeline to cross compress into. 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.

2. PG&E continues to utilize multi-stage/boost compressors to further reduce the amount of gas released during backbone pipeline blowdowns. Multi-stage/boost compressors have a bigger pressure differential which allows compression to much lower levels than the current reciprocating compressors.

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

4. PG&E will evaluate the use of degassing technology on ILI projects and determine if this 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 this technology is a good solution, 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.

5. PG&E will evaluate and consider applying volume thresholds to require a methane abatement strategy for scheduled transmission pipeline blowdowns, based on proposed

measures 2, 3, and 4 above. This will increase the amount of methane abatement activities, thus reducing the amount of emissions.

6. PG&E plans to review and analyze pipeline repair projects that utilized 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. This study will influence decisions to consider a no-blowdown repair.

7. In 2021, PG&E completed the project bundling analysis and has incorporated project bundling as an abatement technique to reduce emissions. In 2022, PG&E plans to further promote and enhance the project bundling process to better capture station maintenance activities and drive decisions early in the project portfolio phase to bundle more often.

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. The portfolio of work varies from year to year in term of assets and nature of the work.

PG&E is targeting an annual abatement of 90 percent of potential gas releases from backbone pipeline clearances and 50 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 2022 Compliance Plan period are forecast through PG&E's 2019 GT&S rate case[2] and 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.

Part 5. Cost Effectiveness/Benefits

Project managers were provided a guidance of $25/Mscf of gas saved to determine which GHG reduction strategies would be cost effective. This guidance was based on EDF's social cost of methane of $1,100 per ton, which is equivalent to approximately $21/Mscf, plus the cost of gas. If the strategy or strategies resulted in less than or equal to $25/Mscf of gas saved, then that strategy or strategies would be implemented as part of the project. The standard cost effectiveness, which includes the cost benefit, for this guidance is $23/Mscf.

[2] A.17-11-009, Exhibit (PG&E-1), p. 5-52, Table 5-16, line 4 and A.17-11-009, Exhibit (PG&E-1), p. 5-53, Table 5-17, line 3

[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

Cross compression represents 75% of the methane abated. In 2020, PG&E expensed $770k performing cross-compression activities. Assuming market value of gas of $2.42/Mscf, the total cost of gas diverted is $1.2 million. Dividing the total spend by the emission reduction savings through cross-compression, the standard cost effectiveness of cross-compression is $4/Mscf.

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 TBD 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 2018 and 2020 Compliance Plan. Emissions reduction 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 2022 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 TBD 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 2022 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; and
- 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)[4] 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 courses, among others, support PG&E's efforts to reduce greenhouse gas emissions and these best practices

Greenhouse Gas Emission Reduction – Gas Transmission Blowdowns

This course reviews the decision-making and documentation process for utilizing methane reduction strategies for gas transmission projects with planned pipeline blowdowns. The process uses an online Greenhouse Gas Feasibility Assessment tool and includes training on how to use

[4] 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.

this tool during project planning. This tool displays process flows which requires that project teams consider the use of methane abatement strategies when planning their work, implement them when feasible, build time into their project schedules, estimate the amount of GHG emissions to-be abated, and complete a post-blowdown evaluation and analysis to determine if further revisions to this process are necessary.

Leak Survey DP-IR Tool

This course is designed to equip the operator with the knowledge and skills to safely and effectively test, operate, and maintain a Heath Detecto Pak-Infrared (DP-IR) leak detection device. The training includes explanation of the DP-IR instrument components and functions, as well as procedures for preparing and maintaining the DP-IR and using the DP-IR to detect gas leaks.

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.

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.

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.

Mobile Leak Survey

Leak surveyors will learn how to safely operate, test, and maintain an Optical Methane Detector device, as well as the DP-IR mobile vehicle. In addition, they'll be able 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 Gas Emergency Response Plan (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 (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 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.

Part 2. Proposed New or Continuing Measure

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 2022 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 2022 and 2023. 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 Training does not directly contribute to emissions reduction. Annual revenue requirements for all planned gas training (including those listed above) were forecasted in PG&E's 2020 and 2023 General Rate Case. For 2022, the gas training forecast is $5.9 million[5]. For 2023, the gas training forecast is $10 million[6]. Please note that these costs include all of gas training, and not just training to support methane emissions reduction. 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.

[5] A.18-12-009, Exhibit (PG&E-8), p. 6-8, line 13
[6] A.21-06-021, Exhibit (PG&E-8), p. 6-9, line 5

CHAPTER 7: GAS DISTRIBUTION LEAK SURVEYS

Part 1. Evaluate the Current Practices Addressed in this Chapter

During the 2020 Compliance Plan, 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 using the Picarro Surveyor along with traditional foot surveys.

In 2020-2021, 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 Distribution Integrity Management Program (DIMP) leak surveys and funding has been included in its 2023 General Rate Case.[7]

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 in the previous four-year leak survey cycle. Therefore, PG&E anticipates a decrease in emissions in subsequent leak survey cycles.

Part 2. Proposed New or Continuing Measure

[7] A.21-06-021, Exhibit (PG&E-3)WP 10-77 to WP 10-81, WP 10-91.

In the 2022 Compliance Plan period, PG&E proposes to integrate vintage leak survey into Optimized Leak Survey (OLS). OLS will prioritize the plats to be surveyed in order to optimize the number of leaks found, minimize the time leaks stay open and reduce emissions.

PG&E will continue to evaluate OLS for Operations. The focus will be on mitigating impact on related compliance requirements. In collaboration with Picarro, Inc., PG&E developed a methodology to combine observed leak rate data from previous surveys, likelihood of failure score from DIMP analysis, methane indications from higher frequency mobile monitoring, and predictive analytics to optimize leak surveys. Implementation includes calculating the predicted number of found leaks for the existing plats to be surveyed, keeping the plats surveyed 4 years ago in the list, with 5 years as the backstop, and prioritizing the plat maps that have a higher residual variance for leak survey. PG&E is working with Picarro to develop a compliance dashboard, to ensure the leak survey and atmospheric corrosion inspections do not fall out of compliance with the deployment of OLS.

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. Transitioning to OLS increases the detection of leaks so that the leaks may be repaired at faster rate and reduce the number of unknown leaks. 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 2022-2023 cost estimates for Gas Distribution Compliance leak survey and Super Emitter Program are as follows:

Compliance

1. Traditional Leak Survey: PG&E forecasts surveying approximately 456k services and associated main in for a forecast cost of approximately $9.6 million in 2022 and approximately 456k services and associated main for a forecast cost of approximately $9.9 million in 2023[8].
2. Leak Survey using Picarro: PG&E anticipates surveying 906k services and associated main for a forecast cost of $11.5 million in 2022 and surveying approximately 906k services and associated main for a forecast cost of approximately $11.9 million in 2023[9].

[8] A.21-06-021, Exhibit (PG&E-3), p. WP 10-11, Table 10-8, lines 52-53
[9] A.21-06-021, Exhibit (PG&E-3), p. WP 10-13, Table 10-10, lines 13-14

In 2016, the cost to conduct leak survey was $23.1 million[10]. The cost from transition from a 5-year to a 3-year leak survey cycle is a cost difference of approximately $6 million.

Transitioning to the optimized leak survey (OLS) will not require incremental funding.

Super Emitter Program
PG&E forecasts approximately $1.3M ($1.4M escalated) to perform super emitter survey in 2022 and 2023[11].

Annual DIMP Leak Survey
PG&E forecasts approximately $0.8M to perform annual DIMP Leak survey in 2022 and 2023[12]. 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.

Part 5. Cost Effectiveness/Benefits

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%. This 33% reduction was applied to the 2016 emissions for found and unknown leaks. 2016 was chosen because the leak surveys were conducted on a five-year survey cycle. By applying the 33% reduction, the expected reduction volume is 138,700 Mscf. The cost effectiveness calculation is the cost difference between 5 to 3-year leak survey, divided by the expected reduction volume, which equals to approximately $44/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 same as the steady state for 5 years.

Transitioning to an optimized leak survey (OLS) will enable PG&E to detect and repair leaks in high leak likelihood areas at an accelerated rate compared to the accelerated three-year leak survey cycle. Cost effectiveness/benefits is dependent on the implementation of optimized leak survey and the number of leak repairs. PG&E is unable to calculate the cost effectiveness/benefit for OLS at this time.

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[10] A.21-06-021, Exhibit (PG&E-3), p. WP 10-5, Table 10-5, lines 3 & 7
[11] A.21-06-021, Exhibit (PG&E-3), p. WP 10-17, Table 10-14, line 13
[12] A.21-06-021, Exhibit (PG&E-3), p. WP 10-25, Table 10-22, line 14

CHAPTER 8: METHANE DETECTION

Part 1. Evaluate the Current Practices Addressed in this Chapter

During the 2020 Compliance Plan period, PG&E continued to use advanced mobile and aerial technologies and engaged additional R&D efforts to improve these technologies. PG&E continued the use of highly sensitive mobile methane and ethane detection technology (Picarro Surveyor), and developed new solutions through R&D efforts, including:

- Piloting light unmanned aerial vehicle (UAV) mounted leak detection technologies for waterway leak survey;
- Exploring Optical Imaging Technologies;
- Evaluating Point and Shoot Detectors; and
- Piloting the use of high sensitivity handheld devices for source gas determination.

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. 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. In addition, PG&E continued to work with the industry to lower cost of sensors. For instance, PG&E supported a project with Operations Technology Development (OTD) to evaluate commercially available methane sensors for leak survey and continuous monitoring applications.

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 as provided in the 2020 Compliance Plan 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: ABOVEGROUND LEAK SURVEY

Part 1. Evaluate the Current Practices Addressed in this Chapter

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 1 in the Introduction, PG&E reported a decrease in fugitive emissions (between 2015 and 2020) 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 2022 Compliance Plan period, PG&E will be evaluating technologies that will be able to quantify emissions from compressor stations and regulator stations (see Chapter 15: R&D Projects)

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

Part 3. Abatement Estimates

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. These surveys improved the emission accounting within Appendix 3 and 7 – Component Leaks, which resulted an increase of emissions in 2017, compared to 2015. 2017 should be the baseline to compare against to accurately capture the emission reduction of quarterly leak surveys.

In 2020, the leak threshold for CARB O&G facilities were decreased from 10k to 1k ppm. This resulted in a 264% increase of emissions, comparing 2019 to 2020. To appropriately capture the emission reduction moving forward, the baseline needs to be updated to account for the decrease in leak detection threshold. By applying 264% to the 2017 baseline Appendix 3 and Appendix 7 – component leak categories, the adjusted baseline is 84.5 MMscf. The abatement is calculated by subtracting the 2017 adjusted baseline and 2020 emissions, which is 71 MMscf.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Per the 2023 General Rate Case, PG&E forecasts $3.2 Million for CARB Leak Survey and $2.5 Million for CARB Leak Repair costs[13].

Per the 2023 General Rate Case, PG&E forecasts $968k for Transmission ground leak survey[14].

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

Part 5. Cost Effectiveness/Benefits

For quarterly CARB leak survey program cost is $5.7 million. The net annual cost, which includes cost savings of gas not emitted by the repairs, is $5.5 million PG&E estimates the abatement to be 71 MMscf, comparing the 2017 adjusted baseline to the 2020 emissions (compressor stations and underground storage component leaks). As a result, dividing the 2023 forecast by the emission reduction savings (i.e., abatement), the cost per Mscf is approximately $78/Mscf.

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

[13] A.21-06-021, Exhibit (PG&E-3), WP 10-75, Table 10-64, line 12
[14] A.21-06-021, Exhibit (PG&E-3), WP 10-69, Table 10-58, line 14

CHAPTER 10: QUANTIFICATION AND GEOGRAPHIC TRACKING

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E began exploring leak quantification through a NYSEARCH project in 2014. The results of this project have established the uncertainty to expect of mobile survey when measuring flow rate of leaks on the distribution system. These results were used in establishing the SE Program described in Chapter 11, Find It/Fix It, in support of Best Practice 21.

In addition, PG&E and NYSEARCH have collaborated with the Pipeline and Hazardous Material Safety Administration to establish a method to verify results found by leak quantification systems.

In parallel, PG&E has initiated other R&D projects with OTD and NYSEARCH to improve and develop new techniques for leak quantification.

Lastly, PG&E developed a centralized, searchable map that shares gas-related emissions data collected over the last three years through its robust system-wide gas emissions survey process. 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

PG&E currently conducts compliance surveys on a portion of its system each year, and uses leak grades, a methodology which ranks leaks based on risk, for repair and monitoring. The SE survey is performed in addition to existing compliance surveys and prioritizes repairs for leaks with a flow rate of greater than 10 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.[15]

In 2020, PG&E was waiting for approval from the CPUC on an acceptable number of belowground Grade 3 leak repairs. The 2020 Compliance Plan rate of 2,000 belowground Grade 3 leak repairs per year as proposed by PG&E was approved in December 2020. Following approval, PG&E ramped up efforts to repair belowground Grade 3 leaks.

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 2020 Compliance Plan period.

Grade 3 Leak Repair

The following table summarizes the 2020 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 6. 2020 Compliance Plan actual Grade 3 leak repairs

	2020		2021	
Above or Below Ground?	Original Grade	Pre-Repair Grade	Original Grade	Pre-Repair Grade
Above	8,186	7,932	5,339	5,093
Below	1,265	191	3,246	2,192

[15] General Order 112-F Section 143.2 Leak Classification and action criteria – Grade – Definition – Priority of leak repair Pages 14-18

Please note that the values above are based on a data screenshot at the end of 2021. There could be further data refinements that will be reflected in the 2021 Natural Gas Leakage Abatement Report.

Super Emitter (SE) Program

In the 2020 Leak Abatement OIR Report, emissions from distribution mains and services leaks totaled 505 MMscf with the SE Program. Without the SE Program, the total emissions would have totaled 691 MMscf. The abatement is the difference between the emissions without the SE program, and the emissions with the SE program, which is 186 MMscf. The number of SEs repaired in 2021 will be provided in PG&E's 2021 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 2020 Compliance Plan period:

Grade 3 Backlog Reduction

Using the 2021 pre-repair Grade 3 leak data, PG&E spent approximately $15.5 million to repair 2,064 belowground Grade 3 leaks. The net annual cost, which includes cost savings of gas not emitted by Grade 3 repairs, is $15.3 million. PG&E estimates the abatement from belowground Grade 3 leak repairs to be approximately 37 Mscf per leak.[16] The emission reduction savings from repairing 2,064 belowground grade 3 leaks is 76 MMscf. As a result, dividing the total spend in 2021 by the emission reduction savings from repairing 2,064 belowground grade 3 leaks, the cost per Mscf is approximately $201/Mscf.

Super Emitter (SE) Program

In 2020, PG&E spent approximately $0.9 million for 123 super emitter leak repairs. For 2022, PG&E forecasts to spend $1.4 million for SE surveys. The net annual cost for the program, which includes the SE survey, SE repair, and cost savings not emitted by SE is $2.1 million. PG&E estimates the abatement from SE leak repairs to be approximately 689 Mscf per leak.[17] The emission reduction savings from repairing 123 SE leaks is 85 MMscf. As a result, dividing the net annual cost by emission reduction savings from repairing 123 SE leaks, the cost per Mscf is approximately $25/Mscf for the SE Program.

Meter Set Leak Management

[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.

In 2020, PG&E deployed the bubble size-based approach to characterize meter set emissions. The meter set leaks (MSL) are soap tested and repaired on an immediate response or scheduled basis. In a study with GTI and CARB, the majority of MSLs found were small in size and represented an emission rate of less than 0.001 scfh. In 2021, the meter set emissions in the RY 2020 Leak Abatement Report were quantified using the bubble classification approach.

In 2021, PG&E spent approximately $7.6 million for 68,382 meter set leak repairs. The net annual cost, which includes the cost savings of gas not emitted by MSL repairs, is $7.1 million. PG&E estimated the abatement from prioritizing meter set leak repairs to be approximately 192 MMscf[18]. As a result, dividing the net annual cost by emission reduction savings from the scenario above, the cost per Mscf is approximately $37/Mscf for the prioritization of MSL repairs.

Part 2. Proposed New or Continuing Measure

In 2022, PG&E plans to keep the SE threshold at 10 scfh.

In 2023, PG&E is requesting the option to lower 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 evaluate decreasing the threshold to meet the abatement goals. This option if exercised will increase the number of super emitter indications to roughly 500 for the first year, and this number will decrease in the subsequent years because of the annual detection of these leaks. As part of this option, PG&E proposes to repair larger leaks via lowering the threshold, regardless of grade, and repair belowground grade 3 leaks at a lower rate to manage the backlog, as discussed below. Assuming SE survey costs remain the same at $1.4 million, an average leak repair cost of $7,500 and 500 SE leak repairs resulting in total abatement of 213 MMscf, the cost effectiveness is approximately $22/Mscf. For comparison, the cost effectiveness calculation for 2,064 belowground grade 3 leak repairs is $201/Mscf.

If PG&E decides to lower the SE threshold in 2023 and given the increase in methane reduction due to the resulting increase in the number of large leak repairs, PG&E proposes to reduce the number of belowground Grade 3 leaks that it repairs from 2,000 per year to 1,000 leaks per year. As shown in Part 3 below, this change is justified given the fact that super emitter leak repairs are ten times more cost effective at reducing methane emissions than repairs of non-super emitter belowground Grade 3 leaks.

PG&E's BP 21 compliant leak repair program proposal for 2022-2023 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.

[18] 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.

- PG&E will also find and repair up to the leaks that emit the highest amounts of methane in the system (the "Super Emitters") as proposed above at the existing threshold of 10 scfh in 2022, with the option to lower the threshold to 7 scfh in 2023.
- 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.
- As discussed above, if PG&E exercises its option to reduce the SE threshold from 10 to 7 scfh in 2023, in recognition of the methane reductions that will be achieved by lowering the super emitter threshold, PG&E proposes to reduce the currently-approved repair rate of belowground Grade 3 leaks of 2,000 leaks per year, down to 1,000 leaks per year in 2023.[19] This target will be measured by the original (as-found grade) of the repaired leak, regardless of whether the leak as-repaired becomes a different grade. belowground
- PG&E will continue to repair all aboveground Grade 3 leaks, including meter set leaks, within 3 years.

Part 3. Abatement Estimates

Based on 2020 leak repair data and assuming that leaks are open for three years, the emissions per SE leak is 689 Mscf and for non-Super Emitters (NSEs), the emissions is 37 Mscf per leak. The emissions saved from the repair of one SE leak is equal to the repair of approximately 18.6 NSE leaks.

Based on the proposed option of reducing the 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. On the other end, the repair of approximately 2,000 belowground Grade 3 leaks will abate approximately 76 MMscf. This shows that reducing the SE threshold is much more effective than repairing belowground grade 3 leaks, independent of the size. Accordingly, if PG&E exercises its option to reduce the SE threshold from 10 to 7 scfh in 2023, PG&E is requesting approval to repair NSE belowground Grade 3 leaks at a rate of 1,000 leaks per year.

Part 4. Cost Estimates and Average Annual Revenue Requirement

If PG&E exercises its option to reduce the SE threshold from 10 to 7 scfh in 2023, we introduce additional gradable leaks, including 1 and 2 for the first year of implementation. As stated above, this will add cost to the SE leak repair program, which was not forecast in the 2023 GRC.

Part 5. Cost Effectiveness/Benefits

As stated in Part 1 above, based on the 2021 leak repair data, the cost per Mscf (for 2,064 belowground Grade 3 leak repair abated emissions over 3 years) is $201/Mscf.

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[19] In PG&E's 2023 GRC, 2,000 belowground 3 leak repairs per year are forecast for the 2023-2026 period. However, PG&E also proposes to continue the New Environmental Regulations Balancing Account (NERBA) to adjust revenues if the volume of repairs, as approved in PG&E's compliance plan, varies from this forecasted rate.

The current SE Program cost per Mscf is an order of magnitude less at $25/Mscf. The proposed SE threshold decrease of 7 scfh will further improve the cost effectiveness to $22/Mscf.

As discussed above, PG&E is requesting the option to decrease the SE threshold from 10 to 7 scfh in 2023. SE leak repairs continue to be a more cost-effective measure in reducing emissions from gas distribution leaks over belowground Grade 3 leak repairs, justifying a reduction of the number of belowground Grade 3 leak repairs to 1,000 leaks per year in 2023, if PG&E exercises the option to reduce the SE threshold.

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 (AMSE) standards. The program includes continuous evaluation of tools, technology, and procedures to address changes in code and compliance.

As a result of the 2018 Compliance Plan, PG&E has implemented the enforcement of NPT standard for threads, following the observation of the R&D project performed with NYSEARCH. In the 2020 Compliance Plan period, PG&E published the following guidance documents:

- New Gas Design Standard B-40.4, “Threaded Flanges and Threaded Reducing Flanges”
- New Gas Design Standard B-40.3, “Blind Flanges”
- Revision to Gas Design Standard A-36, “Design and Construction Requirements for Gas Pipelines”
- New Gas Design Standard B-23.1, “Elbolets”
- Revision to Utility Procedure TD-6100P-11, “Meter Valve Maintenance (60 psig or Less)”
- New Gas Design Standard B-23.2, “Threaded Nipolets”
- New Gas Design Standard C63.1, “Blackhawk and TD Williamson Stopper-Style Line Stopper Fittings”
- Revision to Gas Design Standard B-13.3, “Concentric Reducing Nipple (Swage Nipple)”
- Revision to Gas Design Standard F-80, “Meter Valves”
- Revision to Gas Design Standard B-13.2, “Threaded-One-End (TOE) Pipe Nipples”
- Revision to Gas Design Standard A-34, “Pipe Test Design Requirements”
- Revision to utility procedure TD-4820P-05, “Repair Method Selection for Steel Distribution Pipeline”
- New Gas Design Standard F-71, “Valves for Instrument, Control, and Sampling Piping Systems”
- Revision to Engineering Material Specification EMS-5020, “Steel Threaded Pipe Nipples, Gas Meter Assemblies, Meter Nuts, and Forged and Malleable Iron Threaded Gas Fittings”
- Revision to Gas Design Standard B-13.1, “Extra-Heavy Pipe Nipples”
- Revision to Gas Design Standard B-12.3, “45° Threaded Elbow”
- Revision to Gas Design Standard B-12.4, “Reducing Street Elbow”
- Revision to Gas Design Standard B-14.2, “Reducing Threaded Tee”
- Revision to Gas Design Standard B-13.5, “Stainless Steel Threaded Nipples”
- Revision to Gas Design Standard B-12, “Standard 90° Threaded Elbows”
- Revision to Gas Design Standard B-12.2, “Standard 90° Threaded Street Elbows”
- Revision to Gas Design Standard B-10, “Standard Pipe Caps”
- Revision to Gas Design Standard B-10.1, “Standard Pipe Plugs”
- Revision to Gas Design Standard B-12.1, “Standard Reducing 90° Elbows”

- Revision to Gas Design Standard B-11, "Standard Threaded Pipe Couplings"
- Revision to Gas Design Standard B-14.1, "Standard Threaded Street Tee"
- Revision to Gas Design Standard B-14, "Standard Threaded Tee"
- Revision to Gas Design Standard B-15, "Standard Threaded Unions"
- Revision to Gas Design Standard B-15.1, "Threaded Bushing"
- Revision to Gas Design Standard B-11.1, "Threaded Reducers (Bell Reducers)"
- Revision to Gas Design Standard B-30, "90° Pipe Bends"
- Revision to Gas Design Standard A-17, "Pipe Threading and Threaded Joint Connection"
- Revision to Gas Design Standard A-90, "Polyethylene Gas Distribution System Design"
- Revision to Gas Design Standard B-13, "Standard Threaded Pipe Nipples"
- Revision to Gas Design Standard B-17, "Pipe Thread Sealants"

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 rate cases under Operational Management and Operational Support[20]. 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.

[20] A.21-06-021, Exhibit (PG&E-3), 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 2020 Compliance Plan period, PG&E converted the power gas at 2 intermittent valves from natural gas to instrument air in Topock.

For Transmission Measurement & Control (M&C)[21] *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 2021, PG&E replaced 2 high bleed controller replacements at one M&C station.

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.

[21] 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 09 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 2020 Compliance Plan period:

- 2 intermittent valves converted to instrument air in Topock, assuming 20 years, the emissions savings is 0.8 MMscf.
- 2 high bleed controller replacements at the one M&C station, assuming 20 years, the emission savings is 6.5 MMscf.

In 2017, PG&E collected more detailed data from individual facilities on all venting components as part of an inventory for the CARB Oil and Gas Rule and accounted for devices previously not considered pneumatics. This resulted in an overall higher device count and higher emissions estimate. In order to show effectiveness, the baseline needs to be updated to account for improved inventory and reporting in this category.

Part 2. Proposed New or Continuing Measure

For 2022-2023, PG&E plans to replace/remove 10 high bleed controllers at two M&C stations.

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. In the 2022 Compliance Plan period, PG&E plans to convert the power gas at 18 intermittent bleed valves from natural gas to instrument air in Hinkley. There are no incremental requirements associated with this Best Practice.

Part 3. Abatement Estimates

For the 2022 Compliance Plan period:

- 10 high bleed controllers at two M&C stations, assuming 20 years, the emissions savings is 33 MMscf.
- 18 valves being converted to instrument air in Hinkley, assuming 20 years, the emissions savings is 7.5 MMscf.

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 are forecasted in the General Rate Cases. 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 had roughly 3,001 calls in 2018, 5,858 calls in 2019, and 1,824 calls in 2020.

PG&E's Dig-in Reduction Team (DiRT) provides in-person safe excavation trainings, free of charge to the public. In 2018, 2019, and 2020, PG&E provided 226, 148, and 132 classes, respectively.

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 2020, as a result of these ongoing programs, PG&E experienced 1.10 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.[22] This is communicated to excavators through the Underground Service Alert (USA) Ticket process; the locator, upon identifying the transmission facility, arranges a field meet with the excavator to discuss the schedule and stand-by process. PG&E provides this service (locating, field meet, and stand-by during excavation) free of charge.

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 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

[22] 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.

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 2020 Leak Abatement OIR Report, PG&E reported 4 MMscf in transmission all damages, which is a 95% decrease, compared to the 2015 baseline. Comparing 2019 to 2020, there was an increase in emissions mainly due to larger pipeline size damages.

In the 2020 Leak Abatement OIR Report, PG&E reported 39.7 MMscf in distribution all damages, which is a 73% decrease, compared to the 2015 baseline. Comparing 2019 and 2020, there was a decrease in emissions due to a decrease in the number of damages. Although there was a decrease in emissions, COVID-19 impacted PG&E's response time due to headcount impacts (sick employees, employees under quarantine due to close contact, etc.).

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 2022 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 2020 emissions, the abatement or difference in emissions is 184 MMscf.

Part 4. Cost Estimates and Average Annual Revenue Requirement

PG&E's Damage Prevention public awareness, DiRT and standby costs and annual revenue requirements are forecast in PG&E's 2023 General Rate Case as follows:

2022
Public Awareness[23]: $2.4 million
Dig-In Reduction Team[24]: $3.4 million
Standby[25]: $6.5 million

2023
Public Awareness[22]: $4.5 million
Dig-In Reduction Team[23]: $3.5 million
Standby[24]: $7.5 million

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 $15 million, which includes the sum of the activities in part 4 and the cost of gas saved. The standard cost effectiveness calc is the net annual cost divided by the abatement estimate in part 3, which is $82/Mscf. No incremental work is planned to comply with this Best Practice.

[23] A.21-06-021, Exhibit (PG&E-3), WP 5-4, Table 5-3, line 29
[24] A.21-06-021, Exhibit (PG&E-3), WP 8-12, Table 8-6, line 86
[25] A.21-06-021, Exhibit (PG&E-3), WP 8-10, Table 8-5, line 35

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

During the 2022 Compliance Plan period, PG&E's R&D team will be pursuing the following projects under this measure:

Project 1: Regulator Station Emission Factor

PG&E proposes to update the regulator station emission factor through a 2020 NYSEARCH project. The project objective is to develop a classification framework and methodology that will provide more accurate quantitative estimation of methane emissions at regulator stations. The project goal is to show that the customization of emissions through classification of different types of equipment at regulator stations is a valid method that can improve emission calculation accuracy. This project will provide a framework to calculate and abate emissions in the Transmission M&R Station category.

Project 2: Bubble Classification method on Station Facilities

PG&E will evaluate the bubble classification method for station facilities through a 2022 OTD project. The project objective is to perform a similar study as the meter set, but at higher pressures. This project will establish emission factors based on the bubble sizes and pressures. This project will improve the emission estimate and calculation for Distribution and Transmission M&R Station Pipeline Leaks.

Project 3: Flaring Alternative

PG&E proposes to pursue new methodologies to reduce methane emissions from gas operations activities. NYSEARCH and Stanford is looking into an alternative to flaring by catalytically oxidizing methane at lower temperatures. The project team designed a small lab-scale methane oxidation reactor over the course of phase 1 and phase 2. In phase 3, the project team will design a portable device to oxidize methane in a flameless process at low temperatures and evaluating the feasibility of using the device in the field. The project team has completed testing to compare the champion catalyst with the commercial palladium-based monolith catalyst system. The results showed that the formula is indeed more reactive. Next steps are to collaborate with the vendor to design and scale the oxidizer device. This project has the potential to further reduce emissions during Non-Emergency Blowdowns.

Project 4: Vehicle-Based Measurements and Emissions

PG&E R&D and Picarro is collaborating to develop a method to calculate the Distribution M&S emissions using measurement data collected from the car. Since the full distribution system is surveyed annually, the measurements can be used to calculate overall emissions in this category. An indication can be assigned an emission factor, based on the size, and using the uncertainty method produced by NYSEARCH, an emission estimate can be produced. This project will improve PG&E's method to calculate Distribution M&S emissions.

Project 5: High Sensitivity Methane Detector for Estimating Flow Rate

A new handheld sensor developed by RKI Instruments, based on Open Path Laser Spectrometer technology, has high sensitivity into the low parts-per-billion. Unlike conventional technologies, it was designed with an open-path chamber which relies on passive migration of gas molecules into the sensor. PG&E will evaluate the tool as a means to quantify leak rate. This includes preparing a test plan, coordinating controlled testing/field visits and collecting data using various techniques, analyzing the data and coming up with an uncertainty calculation of the measurements. This project has the potential to provide a quicky & easy way to quantify emissions at each individual leak source.

Project 6: Vented Emission Measurements

Currently, compressor emissions for Transmission Compressor Stations and Underground Storage are collected using an annual measurement, which may not be representative of actual emissions. In addition, there is variability on the measurement based on the acoustic sensor and measurement location. This project will evaluate alternatives such as continuous monitoring devices and more frequent measurements using UAS technology, to better understand and characterize the higher emitting facilities, and implementing strategies & action to reduce emissions.

For additional projects, please refer the R&D dashboard, that is submitted to the CPUC on a bi-annual basis.

Project 7: Degassing Technologies

PG&E will evaluate the use of degassing technology on ILI projects and determine if this 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 this technology is a good solution, 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.

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 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 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.

Part 3. Abatement Estimates

R&D Projects 1 and 2 will not directly abate methane emissions, but rather provide PG&E with the ability to directly calculate emissions from its regulator stations. R&D Projects 3 will evaluate an alternative to further reduce emissions during flaring activities. R&D Projects 4 and 5 will research alternative methods to estimate emissions in the distribution M&S category. R&D project 6 will evaluate alternative technologies to better characterize compressor emissions in Compressor Station and Underground Storage Facilities. R&D project 7 will evaluate degassing technologies to support methane abatement activities on smaller transmission projects.

Part 4. Cost Estimates and Average Annual Revenue Requirement

PG&E forecasts approximately $6.8 million in 2022 and approximately $11.5 million in 2023 for the Gas R&D Deployment program[26] . Please note that these costs are for the entire Gas R&D Deployment program, and not just 2022 Compliance Plan activities. The forecast includes approximately $1.6 million for methane abatement projects. 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.

[26] A.21-06-021, Exhibit (PG&E-3), WP 13-10, Table 13-10, line 1

SECTION C. SUPPLEMENTAL MATERIALS

1. Measure 8: PASS_PG&E Internal LASEN Drone Testing.pdf
2. Measure 10,15: PASS_NYSEARCH T-786 Classifying Methane Emissions at Regulator Stations
3. Measure 15: PASS_NYSEARCH M2017-004 Phase III Methane Oxidation Catalysts
4. Measure 15: PASS_PG&E Internal Schlumberger Valve IQ Testing
5. Measure 15: PASS_PG&E Internal SeekOps Emission Quantification

SECTION D. CONCLUSION

PG&E's 2022 Compliance Plan will continue its progress toward meeting the emissions reduction goals of 20 percent and 40 percent by 2025 and 2030, respectively. However, there are current limitations on reaching the reduction goal due to those emissions that are population-based. In order to meet the 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 Innovation 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 2025, PG&E will continue to evaluate Optimized Leak Survey for Operations and the reduction of the Super Emitter threshold, to extend blowdown reduction strategies to Compressor Station and Storage facilities, to lower the pipeline pressure for scheduled backbone transmission projects, and to apply degassing technologies for ILI and lower volume transmission projects.

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

The following table summarizes revisions since the previous publication of GP-1100: Asset Management Strategy & Objectives, Revision 6, 08/07/2020.

Table 5 – SAMP Change Log

Revision 8a Changes			
Section	**Change**	**Reason for Change**	**Implication of Change**
Entire Document	• Improved description of gas operations line of sight focus areas. • Update all references to "goals" to "focus areas."	• Updated language	Updated Information
Section 1.1, Table 1	• Deleted and replaced with a bulleted list of Gas Operations' 2021 focus areas.	• Updated language	Updated Information
Section 1.2	• Added reference to Section 2.1 for Asset Management System elements.	• Updated language	Updated Information
Section 1.2, Table 1 (formerly Table 2)	• Updated LNG/CNG section to reflect consolidation of GP-1106 and GP-1107 into a single document, GP-1106, "LNG/CNG Asset Management Plan." • Added a footnote to the table to communicate the consolidation of GP-1106 and GP-1107, including cancellation of existing GP-1107.	• GP-1106 and GP-1107 were incorporated into a single document GP-1106 in the 2021 published version	Updated Information
B. Related Documents, Table 7	• Updated title to GP-1106 to "LNG/CNG Asset Management Plan." • Added footnote to communicate the consolidation of GP-1106 and GP-1107, including cancellation of existing GP-1107.	• GP-1106 and GP-1107 were incorporated into a single document GP-1106 in the 2021 published version	Updated Information
D. Gas Operations Work Process Architecture	• Updated Figure 5 to align with current leadership information.	• To align with current leadership information.	Updated Information

Revision 8a Changes (continued)			
Section	**Change**	**Reason for Change**	**Implication of Change**
G. Gas Operations SAMP and AMPs Comm. Plan Summary, Table 11	• Updated Delivery Date column containing "August following AMP Publication" to "August or following AMP Publication." • Updated row containing GP-1106 and GP-1107 to align with consolidation of the two gas plans including deleting reference to GP-1107, updated title of GP-1106, and added a footnote to communicate the change. In the "Delivery Date" column, removed text: "Throughout the year as issues arrive."	• GP-1106 and GP-1107 were incorporated into a single document GP-1106 in the 2021 published version	Updated Information
Revision 8 Changes (Published 04/21/2021)			
Rev number	• Updated revision number to Rev: 8	• Advanced the revision number to correct the error of the revision number not being updated with the 2018 revision.	Corrected Information
Table of Contents	• Updated content to match document headings, tables, and figures	• Updated content to remain current	Updated Information
1.1	• Added statement around Asset Management Plans having the full commitment of Gas Ops Senior Leadership	• Emphasis on importance of the documents	Updated Information
1.1	• General verbiage updates and grammatical corrections	• Improve readability of the document	Updated Information
1.1	• Updated Line of Sight Goals table to 2021 Focus Areas, Goals, and Objectives	• Updated for alignment with the 2021 Gas Ops LOS goals	Updated Information
1.1	• Added statement to describe how out-of-cycle updates will be assessed and incorporated	• Further clarifies the "living nature" of the document and provides process for out-of-cycle updates	Updated Information

Revision 8 Changes (continued)			
1.2	• Updated Safety Culture section per guidance received from GSE Team	• Alignment of Gas Safety Excellence Management System language	Updated Information
1.2	• Added "Asset Management Systems" to GSE components	• Feedback from Gas Safety Excellence team to incorporate	Updated Information
1.2	• GSEMS guides the Gas Ops organization – revised language to support	• GSEMS requirements guide the organization	Updated Information
2.1	• Added footnote for the Gas Safety Excellence webpage	• Provide reference to where information on Gas Safety Excellence Management System, PAS 55, and ISO 55001 documentation can be found	Updated Information
2.1	• General verbiage updates and grammatical corrections	• Improve readability of the document	Updated Information
2.2	• General verbiage updates and grammatical corrections	• Improve readability of the document	Updated Information
2.2	• Updated table 2 to reflect term "Pipeline" instead of "Line Pipe"	• Provide consistency in the document	Updated Information
2.3	• Updated table with 2021 focus areas and 3–5 year objectives	• Updated for alignment with the 2021 Gas Ops LOS document	Updated information
2.4	• Corrected inadvertent grammatical error in the subjects that the plans for each asset family address	• Grammatical correction	Consistency across all AMPs
2.4	• Added sentence on the use of the Corrective Action Program (CAP) to track asset management assessments, audits and reviews in a traceable, verifiable and complete manner	• Lesson learned from Electric Operations	Updated Information
2.4.1	• Removed reference to Risk-Informed Budget Allocation (RIBA) process and replaced with Risk-Based Portfolio Prioritization Framework (RBPPF)	• Updated portfolio prioritization standard was published in January 2021 that replaced RIBA	Updated Information
2.4.1	• Updated reference date of Appendix D Process Management Framework to reference February 2021	• Updated to reflect latest information and process management structure	Updated Information

Revision 8 Changes (continued)			
2.5	• Added RISK-5004S Risk-Based Portfolio Prioritization Framework (RBPPF) that will be utilized during the Integrated Planning Process on a moving-forward basis	• Updated portfolio prioritization standard was published in January 2021 that replaced RIBA	Updated Information
2.6	• Removed reference to use of the RET Risk Register	• RET Risk Register no longer is being utilized with the transition to MAVF as directed under the Safety Modeling Assessment Phase (S-MAP) Settlement Agreement, approved in Decision 18-12-014	Updated Information
2.6	• Included language around evolution of the new risk models and the continued needs assessment for non-loss of containment models	• Updated per discussions with Asset Family SMEs	Updated Information
2.6	• Updated reference date to 2021 for Gas Operations risks on the Corporate Risk Register	• Updated to reflect current year information	Updated Information
2.6	• Removed reference to Session D	• Process change	Updated Information
2.6	• Updated timeline on bowtie model development for Gas Ops risks to be in conjunction with the GRC 2023 submittal	• Provide timeline of bowtie model development	Updated Information
2.6	• Updated Figure 4 – Corporate Risk Register with information provided by EORM as of December 2020	• Updated information was available as of December 2020	Updated Information
3.3	• General verbiage updates, date reference updates, and grammatical corrections	• Improve readability of the document and to provide relativity to current cycle update	Updated Information
4.0	• Updated role of Sr. Director, Safety, Quality and Contract Management (includes Gas Safety Excellence)	• Removed “approve” from role of Sr. Director, Safety, Quality and Contract Management (includes Gas Safety Excellence)	Updated Information
5.0	• Updated use of horizon scanning of the industry and best practice incorporation	• Maintain continuity with individual AMPs	Updated information

Revision 8 Changes (continued)			
Appendix A	• Updated change log with 2021 changes	• Updated information	Updated Information
Appendix B	• Added Risk-Based Portfolio Prioritization Framework	• New standard was issued in January 2021	Updated Information
Appendix D	• Updated Gas Operations Work Process Architecture • Updated language to reflect other processes and functions	• Updated information was available on the GOKP website	Updated Information
Appendix E	• Updated Table 9 with RBPPF - Risk-Based Portfolio Prioritization	• New acronym utilized in the addition of RISK 5004S	Updated Information

F. Change Log

The following Table 18 summarizes revisions for Revision 8, since the previous publication of GP-1101: Transmission Pipe Asset Management Plan, Revision 7, which was published August 2020.

Table 18. Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Updated statistics, tables, and figures	Annual data update	Updated content
Section 2	Updated statistics, tables, and figures	Annual update	Updated content.
Section 3	Updated	Consistency with other asset management plans	Updated with current business risk practices
Section 4	Updated	Annual update	Updated long term goals
Section 4.2	Updated	Annual update	Updated program content
Section 5	Updated	Added content on process safety indicators and climate vulnerability assessment	Documents recent results and forward-looking continuous improvement. Added content on process safety indicators and climate vulnerability assessment
Appendix B	Updated	Annual update	Improved threat knowledge
Appendix C	Updated	Non-RAMP Risk Drivers	Added new table to document non-loss of containment threats which were excluded from the RAMP TPLoC model
Appendix D	Updated	General update	None
Appendix E	Updated	General update	None
Appendix F	Updated	General update	None
Appendix G	Re-ordered, no change	General update	Deleted old appendix G “Summary of Integrated Programs”. Moved “Asset Life Cycle” from appendix I to G.
Appendix H	Re-ordered, updated	Annual update	Moved “Research Development and Innovation” from appendix J to H.
Appendix I	New	New content available	Enables proactive risk assessment and mitigation planning for future risk changes due to climate vulnerability
Appendix J	Re-ordered, updated	Annual update	Moved “Key Performance Indicators” from appendix H to J. Content updated. Added a year to facilitate year over year comparison. Added summary of TIMP monthly metrics report.

F. Change Log

Table 15 summarizes revisions to the publication of the GP-1102: DMS Asset Management Plan, Revision 7, August 2020.

Table 15. Asset Management Plan Change Log

Revision 8a (Publication Date: DRAFT Effective Date: DRAFT)			
Section	**Change**	**Reason for Change**	**Implication of Change**
3.1.1	Updated Figure 12 to correct “Wildfire” score from “2300” to “23,000.”	Updated With Current Data	Updated Information
Section 4	Updated existing strategic objectives in Table 5 per RCC-approved changes: • Revised language in Strategic Objective #1 to document all abnormal operating conditions by the end of 2021 and resolve backlog by the end of 2026. • Revised Strategic Objective #7 date from 2021 to 2023. • Added Strategic Objective #13 to develop a long-term strategy by the end of 2023 to eliminate the remaining low-pressure distribution systems for inclusion in the 2027 GRC.	Updated Language	Updated Information
Section 4.1	Updated Table 6 with strategic objective changes implemented in Section 4 per RCC approval.	Updated Language	Updated Information
Section 5	Updated Table 8 with strategic objective changes implemented in Section 4 per RCC approval.	Updated Language	Updated Information
Appendix G	Updated key life-cycle management manuals and guidance documents in Table 16, including revised language for Strategic Objective #1 and removal of Gas Design Standard A-93.2, “Deactivation of Plastic Services,” from Life Cycle Phase, “4. Retire.”	Updated Language	Updated Information

Table 15. Asset Management Plan Change Log (continued)

Revision 8 (Publication Date: 08/18/2021 Effective Date: 08/18/2021)			
Section	**Change**	**Reason for Change**	**Implication of Change**
Entire Asset Management Plan	Updated tables, figures, and asset inventory information	Updated with Current Data	Updated Information
Section 1	Aligned paragraph with other Asset Family Management Plans	Document Consistency	Consistency with Other Asset Family Management Plans
Section 2.1	Updated SCADA to align with Measurement and Control Asset Management Plan (GP-1104)	Updated Information	Updated Information
Section 2.1	Updated Table 1 to align with definitions within TD-4125P-10	Updated Information	Updated Information
Section 2.1	Updated Figure 1 to align with Regionalization Effort	Updated map due to developments on regionalization effort	None
Section 2.2.2	Updated to include learnings from ADB-2021-01	Updated Information	Updated Information
Section 2.3	Updated Figure 10 – Life Cycle Phases to align with other Asset Family Management Plans	Document Consistency	Consistency with Other Asset Family Management Plans
Section 3 (and subsections)	Aligned language with other Asset Family Management Plans	Document Consistency	Consistency with Other Asset Family Management Plans
Section 4	Updated Table 5 with new Strategic Objectives and changes approved via the February 2021 RCC	Updated Information	Updated Information
Section 4	Changed language from “Gas Operations Goals” to “Gas Operations Focus Areas”	Alignment with Line of Sight	Updated Information
Section 4.1	Updated Table 6 with new Strategic Objectives and changes approved via the February 2021 RCC	Updated Information	Updated Information
Section 4.2	Updated Plastic Pipeline Replacement Program and Gas Pipeline Replacement Program scope to include minimizing releases of natural gas	Updated to include learnings from ADB-2021-01	Updated Information
Section 4.2	Added Fitting Mitigation Program to table per 2023 GRC	Updated Program in the 2023 GRC	New Mitigation Program
Section 5.1	Updated areas of progress not specifically tied to a strategic objective	Updated Information	Updated Information
Section 5.2	Added additional Areas for Continuous Improvements to Table 9	Updated Information	Updated Information
Section 5.2	Provided details on additional areas of maturity: Process Safety Indicators Climate Resiliency	Updated Information	Updated Information

Table 15. Asset Management Plan Change Log (continued)

Revision 8 (Publication Date: 08/18/2021 Effective Date: 08/18/2021)			
Section	**Change**	**Reason for Change**	**Implication of Change**
Section 5.3	Added the Asset Management discussion group to AGA benchmark activities	Updated Information	Updated Information
Section 5.4	Moved Research and Development details to Appendix H	Document Consistency	Consistency with other Asset Family Management Plans
Appendix A	General Table 10 Updates	Updated Information	Updated information
Appendix B	Updated Figure 12 – DMS Asset Threat Matrix per approved matrix from April 2021 RCC meeting	Updated Information	Updated information
Appendix B	General language updates to Key Threats section to align with the PHMSA reportable “significant” definition	Document Consistency	Consistency with other Asset Family Management Plans
Appendix C	Updated Table 12 to identify those items from the Risk Register that may not be covered by the Enterprise Risk Model for Loss of Containment on Gas Customer Connected Equipment	Maintain visibility to risks that may not be covered by an Enterprise Risk Model	Data Continuity
Appendix D	General updates to Table 13	Updated Information	Updated Information
Appendix E	General updates to Table 14	Updated Information	Updated Information
Appendix F	Updated change log with updates made since Revision 7	Updated Information	Updated Information
Appendix G	General updates to Table 16	Updated Information	Updated Information
Appendix G	Updated Mechanical Fittings vs. Fusion Lifecycle Costs analysis with 2021 information	Updated Information	Updated Information
Appendix H	Revised Appendix introduction and provided updated Research and Development project list	Document Consistency	Consistency with Other Asset Family Management Plans
Appendix I	Distribution Main Target Replacement Rate updated in accordance with 2023 GRC submittal	Updated Information	Updated Information
Appendix J	Added new appendix to provide information to risks to asset family associated with climate change	The California Public Utility Commission’s Final Decision (20-08-046) on Disadvantaged Vulnerable Communities and Utility Vulnerability Assessments requires energy utilities in California to undertake climate vulnerability assessments (CVAs) of utility operations, services, and assets, and file these assessments with the CPUC.	None

F. Change Log

The following table summarizes revisions since the previous publication of GP-1103: Customer Connected Equipment Asset Management Plan, Revision 7, August 2020.

Table 13 - Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Updated tables, figures, and asset inventory information	Updated with current data	Updated information
Section 1	Aligned paragraph with other Asset Family Management Plans	Document consistency	Consistency with other Asset Family Management Plans
Section 2.1	Removed information on risk calculation as not applicable to this section	Document consistency	None as risk information is discussed in Section 3.
Section 2.1	Updated Figure 1 to align with Regionalization Effort	Updated map due to developments on regionalization effort	None
Section 2.2	General wording updates	Provide consistency with other documents	None
Section 2.2.1	Provided context around accuracy of regulator data	Demonstrate area of continuous improvement	None
Section 2.2.1	Moved to a weighted average for meter age	Document consistency	Consistency with other Asset Family Management Plans
Section 2.3	Updated Figure 4 – Life Cycle Phases to align with other Asset Family Management Plans	Document consistency	Consistency with other Asset Family Management Plans
Section 3 & subsections	Aligned language to align with GP-1102 and updated Figure 5 with CCE Risk Bowtie	Document consistency	Consistency with other Asset Family Management Plans
Section 4	Updated Table 3 with new Strategic Objectives and changes approved via the February 2021 RCC	Updated information	Updated information
Section 4	Changed language from “Gas Operations Goals” to “Gas Operations Focus Areas”	Alignment with Line of Sight	Updated Information
Section 4.1	Updated Table 4 with new Strategic Objectives and changes approved via the February 2021 RCC	Updated information	Updated information
Section 4.2	Aligned language and Table 5 format with GP-1102.	Document consistency	Consistency with other Asset Family Management Plans
Section 4.2	Moved to “Risk Driver Addressed” from “RET Risk Addressed” in Table 5	RET was retired in 2018 – providing consistency with EORM	Consistency with other Asset Family Management Plans
Section 5.1	Updated Table 6 with new Strategic Objectives and changes approved via the February 2021 RCC	Updated information	Updated information
Section 5.2	Incorporated new Areas for Continuous Improvement in Table 7	Updated information	Updated information

Section	Change	Reason for Change	Implication of Change
Section 5.2	Provided details on additional areas of maturity: Process Safety Indicators and Climate Resiliency	Updated information	Updated information
Section 5.3	Added the Asset Management discussion group and Piping Materials Committee to AGA benchmark activities	Updated information	Updated information
Section 5.4	Moved Research and Development details to Appendix H	Document consistency	Consistency with other Asset Family Management Plans
Appendix A	General Table 8 Updates	Updated information	Updated information
Appendix B	Noted “no change” in the threat matrix from the prior revision 7 published in August 2020.	The Risk & Compliance Committee will review proposed updates in August 2021 during the scheduled Risk and Compliance meeting. The approved threat matrix from the August 2021 CCE annual asset family review will be included in the 2022, Rev. 9 CCE GP-1103 update.	None
Appendix B	General language updates to Key Threats section to align with the PHMSA reportable “significant” definition	Document consistency	Consistency with other Asset Family Management Plans
Appendix C	Updated Table 10 to identify those items from the Risk Register that may not be covered by the Enterprise Risk Model for Loss of Containment on Gas Customer Connected Equipment	Maintain visibility to risks that may not be covered by an Enterprise Risk Model	Data continuity
Appendix D	General updates to Table 11	Updated information	Updated information
Appendix E	General updates to Table 12	Updated information	Updated information
Appendix F	Updated change log with updates made since Revision 7	Updated information	Updated information
Appendix G	Updated Table 14 with new strategic objectives and added additional Key Life Cycle Management Manuals and Guidance Documents	Updated information	Updated information
Appendix G	Updated Powder Coat Over Zinc for Threaded Fittings Lifecycle Costs analysis with 2021 information	Updated information	Updated information
Appendix H	Revised Appendix introduction and provided updated Research and Development project list	Document consistency	Consistency with other Asset Family Management Plans
Appendix J	Added new appendix to provide information to risks to asset family associated with climate change	The California Public Utility Commission’s Final Decision (20-08-046) on Disadvantaged Vulnerable Communities and Utility Vulnerability Assessments requires energy utilities in California to undertake climate vulnerability assessments (CVAs) of utility operations, services, and assets, and file these assessments with the CPUC.	None

F. Change Log

The following table summarizes revisions since the previous publication of GP-1104: Measurement & Control Asset Management Plan, Revision 7, August 2020.

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 1, 2020	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	New data generated new tables	Updated information
Section 3	Added reference to new standard. New content on Corporate bowtie analysis	Updated models	Updated information
Section 4	Updated language to better align with Gas Operations LoS, Strategic Objectives status updated	Updated to better reflect current status	Updated information
Section 4.1	Updates to new estimated completion dates	Update based on new completion date	Updated Information
Section 5.1, 5.2, 5.3	Changed and updated to areas of continuous improvement. Updated to strategic objectives progress and challenges and added reference to Climate Change and Process Safety Indicators (PSI). Added reference to AGA benchmarking and participation	Need to reflect progress and challenges and inclusion of the important topic of Climate Change. Importance and value of benchmarking	Updated and new information
Section 5.4	Updated appendix “Research & Development” and reference to total count	Updated R&D projects that apply to the M&C asset family	Updated and new information
Appendix A	Updated appendix “Related Documents"	Updated list to add two more relevant documents	New information
Appendix B	Updated Threat Matrix	Updates on indicator color	Updated information
Appendix C	Made minor change for added clarification	Need for clarification	Adding information
Appendix D	Applied minor update	Update to accurately reflect roles and responsibilities	Updated information
Appendix E	Added two new acronyms AGA and PSI	Added discussion referencing AGA and PSI	New 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	Added new content	Added Climate Vulnerability Assessment	New information
Appendix M	Updated to latest version of plan	Latest Version to be release soon	Updated report

F. Change Log

The following table summarizes revisions since the previous publication of GP-1105: Compression & Processing Asset Management Plan, Revision 7, 08/07/2020.

Table 17 – Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Update to previous version of Asset Management Plan dated August 7, 2020	Updated information regarding fleet of C&P assets; condition of C&P assets; risks associated with C&P assets; mitigations associated with risks to C&P assets; and continuous improvement activities associated with C&P assets.	Updated information
Section 2.1	Updated Odorizer count and Map to reflect new 5 regions	Change in count and new reorg.	Updated information
Section 2.2	Updated asset inventory, asset condition, asset performance	Changes in asset inventory, improvements, and challenges	Updated information
Section 3.1, 3.3	New content on Corporate Risk Register and bowtie analysis	Transition from RET Risk Register to risk models.	Updated information
Section 4, 4.1	Updated content to better align with Gas Ops LoS and current state of strategic objectives	Need for alignment and better reflect current strategic objectives and status.	Updated information
Section 5.1, 5.2, 5.3	Changes and updates to areas of continuous improvement Updates to strategic objectives progress and challenges and added reference to Climate Change and PSI Added reference to AGA benchmarking and participation	Need to reflect progress and challenges and inclusion of the important topic of Climate Change. Need to address PSI as it relates to CP. Importance and value of benchmarking.	Updated and new information
Appendix A	Updated appendix “Related Documents"	Updated list to add two more relevant documents.	New information
Appendix C	Minor update to Table 14 title	Provides clarification.	Updated title
Appendix D	Minor update to Table 15	Update to accurately reflect roles and responsibilities.	Updated information
Appendix E	Added two new acronyms AGA and PSI	Added discussion referencing AGA and PSI.	New information
Appendix H	Updated appendix “Research & Development”	Updated R&D projects that apply to the C&P asset family.	Updated information
Appendix I	Removed/Replaced	Removed Inactive material/replaced with Climate Vulnerability Assessment content.	Removed old appendix/Replaced with new content
Appendix J	Removed	Has met its specific purpose, no longer needed.	Removed appendix

Appendix F: Change Log

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

Table 39. Changes to the August 2021 Edition

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Update the content in the two 2020 AMP versions and combined into this single document.	Updated information regarding inventory of assets; condition of assets; risks; mitigations; and continuous improvement activities. Combined to produce a single document that more effectively reflects the integrated nature of the LNG/CNG business.	Updated information. Improved applicability of the document to LNG/CNG personnel.

F. Change Log

The following table summarizes revisions since the previous publication of Gas Plan GP-1108, “Gas Storage Asset Management Plan,” Revision 6, August 2019.

Table 23 – Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
1 Introduction	• Added summary of findings from the Aliso Canyon failure mode. • Added reference to DOGGR name change and added definition of the Asset Management System at PG&E	Document improvement	None
2.1 Asset Overview	• Added paragraph summarizing approval of NGSS impacts to assets	Document improvement	None
2.2 - Table 2	• Updated for revised operational statistics	Annual update	None
2.2.1 Storage Reservoir	• Added paragraph on results of CalGEM recent geologic, seismologic and geomechanical studies at Aliso Canyon	Document improvement	None
2.2.2 Storage Wells	• Updated wells count and 2019 results	Annual update	None
2.2.2 Production Casing Table 6	• Updated the number of baselines from 2016 - 2019 taking out the number of re-assessments that were previously included • Removed row for wells assessed with full suite of tests • Removed row for wells re-assessed with full suite of tests • Added figure showing total well population & percentage completed	Reassessments are not considered baselines, so removed from the count to avoid misinterpretation on the number of baselines completed Provide relevant information on the condition of the production casing	None
2.2.2 Sand Inspections	• Updated analysis discussion and trend chart with current data for sand inspection results	Annual update	None
2.2.3 Transmission Pipe	• Updated section on corrosion	Annual update	

Section	Change	Reason for Change	Implication of Change
2.2.4 Surface Equipment	• Updated table with 2019 results and relabeled table column heading from Numbers of wells to "Number of wells equipped with safety Valves • Updated Table 9 valve condition summary and analysis of valve inspection results	Update and provide clarification on the data presented	None
2.2.5 Leak Survey	• Removed table with leak survey data • Updated introductory paragraph to remove references to the data table and add more	Document improvement	Updated information
2.2.6 – Table 10 Summary of Available Asset Data for Storage Wells and Reservoirs	• Removed rows referencing TIMP and FIMP/GPOM data sources	Not relevant for Storage	Updated information
2.3 – Asset Lifecycle	• Changed section title to asset Life Cycle Management and section rewritten to include life cycle costing. • Details on Storage assets moved to new Appendix G	Address Lloyds Audit scope for improvement on lifecycle costing. For consistency with other AMPs moved Storage asset life cycle details to appendix section	New information
3 – Threat and Risks	• Updated the Threat and Risks section to describe the current risk management process and the transition to the Event Based Risk Register (EBRR). New content on Corporate Risk Register and bow tie analysis	Transition from RET Risk Register to risk models	Updated information
3.2 Integrity Management Programs	• Updated information on the TIMP and FIMP integrity management programs	Annual update	Updated information
3.2.2 Key Gas Storage Risks	• Updated section with results from the 2020 Storage Risk Register refresh • Removed previous "Key RET Gas Storage Risks" table	Annual update	Updated information
4 Desired State, Strategic Objectives, Programs and Risk Mitigations	• Updated the section on Regulatory and Legislative Impact on Storage Assets and the section on Strategic Objectives	Provide a summary of regulation changes and update the strategic objectives	Updated information
4.2 Programs and Mitigations Overview	• Updated Well and Reservoir programs scope and timelines	Actualize the programs scope and timeline	Updated information

Section	Change	Reason for Change	Implication of Change
5.1 Strategic Objectives	• Updated strategic objectives, progress, and challenges	Annual update	Updated information
5.2 Areas for continuous Improvement	• Updated focus areas	Keep relevant	Updated information
5.3 Benchmarking	• Updated	Annual update	Updated information
• Appendix A Related Documents	• Removed Reference to RISK 5001P 02 and RISK 5001P 03 • Removed Reference to TD 4011s	These documents no longer exist	Updated information
Appendix G	• Removed previous appendix G: "Summary of Integrated Programs" and substituted with the new Appendix G: "Storage Asset Life Cycle"	Summary of Integrated Programs was redundant as it was already covered in section 4. Created new appendix on asset life cycle for consistency with other AMPs	Updated information
Appendix I	• New appendix for Regulatory Changes	Too much detail for main body	Updated information

F. Change Log

The following table will summarize revisions of this AMP when changes occur.

Table 5. Asset Management Plan Change Log August 2021

Section	Change	Reason for Change	Implication of Change
Entire document	Updated section titles though out to align with other amps	Consistency with other AMPS	Improved consistency
Section 1 Introduction	Added language	Consistency across AMPS	Updated content
Section 2.1	Moved table of organizational units within Gas Ops to appendix	Out of context	Moved to appendix as reference as a basis for the creation of unique identifiers
Section 2.1	Updated definition of critical data	To align with enterprise definition	Consistent terms
Section 2.2.2, Table 1, Figure 1, Figure 2, Figure 3, Figure 4	Updated with current assets as of 2021	Information refresh	None
Section 2.3	Added new material on asset valuation		
Section 3.1	Added language on Risk Register change to event-based risk model	Consistency across AMPS	Updated content
Section 3.1.2	Added information		Better understanding of risk
Section 3.2	Added section on threats	Included information on new DHS requirement resulting from ransomware attack on Colonial Pipeline in May 2021. Also included PSIs	Enhances understanding of threats and process safety.
Section 4, Table 4	Updated Strategic Objectives	Annual review and update	Continuous improvement
Section 4 Gas Data Asset Maturity Model	Added information around progress and included references to Added references to GOV-9001S and GOV-9002S	New material	New requirements defined by enterprise
Section 4.3	Change focus of section on to role data health	Reviewer feedback	Alignment with EDMP on targeting EBRR risk

Section	Change	Reason for Change	Implication of Change
	plays in risk		driver data.
Section 5	Updated information on SO's to include time frame: completed, current, and planned	Clarification	Continuous improvement
Section 5.1	Added more information to the progress and challenges of 2021 work		
Section 5.2	Added information on climate vulnerability	Consistency	Continuous improvement
Section 5.3	New. Added materials on benchmarking	Consistency across AMPs	Improved consistency
Section 5.4	New. Added materials on R&D	Consistency across AMPs	Improved consistency

Change Record

Changes made to the 2021 plan from the 2020 version are noted in the table below.

Topic	2020	2021	Type	Change Detail	SME
Reviewers	Document Reviewer	Throughout	Updated	Beth Neilson added as EP&R document reviewer Removed Mary Ellen Ittenr as PR reviewer and added Richard Hadley	Beth Neilson
Preparers and Approvers	Document Preparer	Throughout	Updated	Angie Gibson, Director, EP&R Strategy and Execution Cecile Pinto, EP&R SE Emergency Planning. Process Improvement and Change Dennis McKeown, Expert Emergency Management Specialist Don Benesh, Expert Technical Writer Julei Kim, Expert Emergency Management Specialist PJ Redmond, Expert Emergency Management Specialist	Dennis McKeown
CERP Change Request Form			Updated	Updated Change Request Form section to include standardized language used in Annexes.	Beth Neilson
Document Relationships	1.5	1.5	Updated	Updated Figure 1-2 and supporting language describing CERP relationship to CERP annexes and other documents.	Dennis McKeown
EPPIC unit	1.6	1.6	Updated	EPPIC acronym defined	Beth Neilson
Situational Awareness and Assessment	3.1	3.1	Added	Added new section on Situational Awareness and Assessment.	Dennis McKeown
HAWC	3.1.1	3.1.1	Updated	Changed name from Wildfire Safety Operations Center (WSOC) to Hazard Awareness & Warning Center (HAWC). Moved content from section 6.2.7 to section 3.1., Situational Awareness and Situational Assessment. Changed capability description from wildfire specific to all-hazards threats.	Jim Ridgeway
AFN	3.2.3	3.2.3	Added	Added link to Access and Functional Needs (AFN) plan filed with the CPUC on February 1, 2021.	Beth Neilson
AFN	3.2.3	3.2.3	Added	Added details on AFN considerations.	Tamyra Walz

Topic	2020	2021	Type	Change Detail	SME
Cybersecurity Incident Notifications	3.2.4	3.2.4	Added	Noted EOC Commander role in notifying PG&E executives upon activation of the Company EOC for a cybersecurity incident.	Dennis McKeown
Weather Emergencies	3.3.2	3.3.2	Added	Added PG&E Meteorology Operations & Analytics (MOA) provides support to the Reliability Group capability details.	Mike Berlinger
DASH	3.5.1	3.5.1	Update	Updated Dynamic Automated Seismic Hazard (DASH) reporting system details.	Megan Stanton
SOPP	3.5.2	3.5.2	Updated	Updated PG&E's Storm Outage Prediction Program description.	Mike Berlinger
POMMS	3.5.4	3.5.4	Updated	Updated PG&E's Operational Mesoscale Modelling System (POMMS) description.	Mike Berlinger
OPW	3.5.5	3.5.5	Updated	Updated PG&E's Outage Producing Wind (OPW) model description.	Mike Berlinger
Debris Flow Modeling	3.5.5	3.5.5	Added	Added reference to section 4.4.5 of the Wildfire Annex for details on debris flow modeling.	Megan Stanton
Exercises	3.7.2	3.7.2	Added	Added Homeland Security Exercise & Evaluation Program (HSEEP) methodology and CPUC General Order 166, Standard 3, parts *a* and *b* references.	Tracey Vardas
ICS	4.3	4.3	Updated	Updated Incident Command System (ICS) concepts and principles descriptions.	Dennis McKeown
Figure 5.1: EOC Organization Chart	5	5	Updated	Updated Figure 5-1 organization chart to depict Command and General Staff deputies to the side of the downtrace lines to other EOC organizational leaders.	Dennis McKeown
Figure 5.1: EOC Organization Chart	5	5	Added	Added Logistics Reporting Unit and MTTC box under Logistics Chief box.	Chuck Williams
Public Safety Specialists	5.1.7.1	5.1.7.1	Added	Added Utility Standard EMER-4002S Agency Representative language.	Dennis McKeown
Aviation Operations Branch	5.2.1	5.2.1	Updated	Deconflicted content with CERP PSPS Annex to identify and separately describe PSPS unique air operations requirements.	Dennis McKeown
Intelligence and Investigation Section	5.3	5.5	Updated	Updated I&I Section content for PSPS events based on current CERP PSPS Annex.	Dennis McKeown

Topic	2020	2021	Type	Change Detail	SME
Planning Section Situation Unit	5.4.1	5.4.1	Updated	Updated language to include reference to LOB predictive model owner participation in Situation Unit.	Dennis McKeown
AFN	5.4.4.1	5.4.4.1	Added	Added Access and Functional Needs (AFN) definition.	Dennis McKeown
Logistic Section Personnel Unit	5.5	5.5	Changed	Changed Figure 5-11 organization chart box titled “Mutual Assistance” to “Mutual Assistance Unit”.	PJ Redmonod
Figure 5-11: Logistic Section Organizaton Chart	5.5	5.5	Added	Added Logistics Reporting Unit and MTTC box under Logistics Chief box.	Chuck Williams
Logistic Section Personnel Unit	5.5.2.6	5.5.2.6	Removed	Removed Internal Crew and Contract Support positions and position responsibilities.	Chuck Williams
Finance and Administration Section	5.6	5.6	Changed	Updated former Finance Unit (now Branch) description.	Jack Liu
Finance and Administration Section	5.6	5.6	Changed	Updated former Human Resource Unit (now Branch) description.	Eric Boettcher
CAISO	7.5.8	7.5.8	Updated	Updated language noting that the California Independent System Operator is the largest of about 40 Balancing Authority registered entities in the Western Interconnection.	Sabrina Bruno
Everbridge Notifications	8.3.4.4	8.3.4.4	Updated	Changed Send Word Now notification language to new Everbridge notification language.	James Neathery
Resource Management	9.1.1	9.1.1	Updated	Updated resource planning and management content.	Kurt Linford
FORCE Tool	9.1.1.5	9.1.1.5	Added	Added Field Operations Resource Calculation of Estimated Time of Restoration (FORCE) Tool description.	Dennis McKeown
Mutual Assistance	9.2	9.2	Added	Added details on Mutual Assistance decision criteria.	Jeff Briggs
Levels of Emergency and Activation Criteria	Appendix B	Appendix B	Updated	Updated Table 11-1 to include Power Generation column earthquake magnitudes for emergency activation levels 3-5. Also updated level 4, Severe, Power Generation column to note that earthquake may affect more than Power Generation assets and facilities.	Megan Stanton

Topic	2020	2021	Type	Change Detail	SME
EOC SharePoint Link	Appendix F	Appendix F	Updated	Updated Emergency Operations Center SharePoint Reports, Forms, Checklists and Tools link to EOC SharePoint	Chris Snyder

Document Control

Gas Emergency Preparedness (GEP), part of Gas System Operations (GSO), 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 10.0).

Where?	What Changed?	Who Initiated the Change?
Throughout	Updated references to several utility procedures and other references to reflect revised documents.	Various
	Updated links as needed.	Various
	Restructured sections for alignment with *CERP* and functional annexes.	Various
	Removed redundant information found in *CERP* or other supporting plans.	Various
3.4.3 Response Priorities	Added protect the environment as a response priority.	Susie Richmond
4.2.2 Gas Incident Reporting	Updated section to remove slang terminology and arbitrary reporting time of "within one hour of the incident"	Kari Kotula
Appendix A	Deleted glossary. Added reference to *CERP* for glossary terms.	Various
Appendix B: Heavy Rains/Landslides causing, Non-Contiguous Pipeline Breaks Response Aid	Added guidance to quarantine any unsafe areas.	
Appendix B: Cyber Security Response Aid	Update verbiage under Assess / Minimize Hazards to the following: Assess the expected impact to system safety and reliability if malicious control of equipment were to occur. If equipment has an increased risk of affecting safety and/or reliability, disconnect the equipment from the network as soon as it is safe to do so or implement other risk mitigation measures. Request Cybersecurity assistance in the review and assessment of the impacted systems.	Fred Doolittle
Page 1-7	Corrected link for "Cold Weather Communications Process"	Don Benesh

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 4

GAS MANUAL: TD-4870M, GAS STORAGE ASSET MANAGEMENT

Gas Storage Asset Management

SUMMARY

This gas manual collects the documents that Pacific Gas and Electric Company (PG&E or Company) uses to manage its underground gas storage assets.

Organization of TD-4870M Effective February 1, 2022

Section	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022	RIMP Version 5
General	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	01. Introduction
General	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	02. Target Audience
General	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	03. Regulatory Jurisdiction for Company Gas Storage Fields
General	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	04. Roles and Responsibilities
General	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	05. Flow of Plan Activities and Frequency of Plan Updates
General	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	06. UGS Integrity Management Process
General	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	07. Data Management
General	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	15. Threat and Risk Management
General	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	16. Asset Management Plans
General	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	17. Prioritization of Risk Mitigation and Control Efforts
General	1	Standard	Appendix UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	Appendix X, Mitigations
General	19	Procedure	UGS-19 Procedure - Abnormal Operating Conditions 2021 12 2.docx	19. Abnormal Operating Conditions
General	20	Standard	UGS-20 Standard - Emergency Response - Emergency Preparedness 2021 12 2.docx	20. Emergency Response / Emergency Preparedness

Organization of TD-4870M Effective February 1, 2022

Section	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022	RIMP Version 5
General	21	Standard	UGS-21 Standard - Security 2021 12 2.docx	21. Security
General	22	Standard	UGS-22 Standard - Management of Change 2021 12 2.docx	22. Change Control
General	23	Procedure	UGS-23 Procedure - Quarterly and Monthly Reporting 2021 12 2.docx	23. Communication Plan
General	26	Standard	UGS-26 Standard - Internal Auditing 2021 12 2.docx	26. Internal Auditing
General	F2	Procedure	UGS-F2 Procedure - Creating and Updating Storage Wellbore Schematics 2021 12 02.docx	Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics
General	G3	Procedure	UGS-G3 Procedure - Creating and Updating Storage Wellhead Diagrams 2021 12 02.docx	Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams
Reservoir Integrity	8	Standard	UGS-8 Standard - Reservoir Integrity Management 2021 12 2.docx	08. Reservoir Integrity
Reservoir Integrity	P12	Procedure	UGS-P12 Procedure - Inventory Verification (Pressure Hysteresis and Semi-annual SI Testing) 2021 12 02.docx	Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification
Well Design	E	Standard	UGS-E Standard - Design and Specifications for Construction of Natural Gas Storage Wells 2021 12 02.docx	Appendix E - Practice 1 Design and Specifications for Construction of Natural Gas Storage Wells
Well Design	E1A	Standard	UGS-E1A Standard - Wellhead Equipment Design 2021 12 02.docx	Appendix E, Practice 1A - Wellhead Equipment Design Standard
Well Design	E1B	Standard	UGS-E1B Standard - Tubular Equipment Design 2021 12 02.docx	Appendix E, Practice 1B – Tubular Design Standard
Well Design	E1C	Standard	UGS-E1C Standard - Cementing 2021 12 02.docx	Appendix E, Practice 1C – Cementing Standard

Organization of TD-4870M Effective February 1, 2022

Section	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022	RIMP Version 5
Well Design	E1D	Standard	UGS-E1D Standard - Well Abandonment 2021 12 02 .docx	Appendix E, Practice 1D – Well Abandonment Standard
Well Fluids	13F-New	Standard	UGS-13F Standard - PGE Fluids Management 2021 12 2.docx	Fluids Control
Well Integrity	9	Standard	UGS-9 Standard - Mechanical Integrity of Wells 2021 12 2.docx	09. Mechanical Integrity of Wells
Well Integrity	10	Standard	UGS-10 Standard - Pressure Tests and Annulus Monitoring 2021 12 2.docx	10. Casing Pressure Tests and Annulus Monitoring
Well Integrity	13	Standard	UGS-13 Standard - Corrosion Monitoring and Evaluation 2021 12 2.docx	13. Corrosion Monitoring and Evaluation
Well Integrity	14A	Standard	UGS-14A Standard - Evaluation of Operational Factors for Wells and Attendant Facilities 2021 12 2.docx	14. Evaluation of Operational Factors for Wells and Attendant Facilities
Well Integrity	14B	Standard	UGS-14B Standard - Well Risk Assessment and Relative Risk Ranking 2021 12 2.docx	14.6 Relative Risk Ranking
Well Integrity	14C-New	Procedure	UGS-14C Procedure - Relative Risk Ranking of Wells 2021 12 2.docx	14.6 Relative Risk Ranking - NEW
Well Integrity	B	Procedure	UGS-B Procedure - Additional Investigations 2021 12 02.docx	Appendix B, Additional Investigations
Well Integrity	C	Procedure	UGS-C Procedure - Casing Inspection Survey Frequency Decision Tree 2021 12 02.docx	Appendix C, Casing Inspection Survey Frequency Decision Tree
Well Integrity	D	Standard	UGS-D Standard - Remedial Options and Decision Tree 2021 12 02.docx	Appendix D, Remedial Options and Decision Tree
Well Integrity	K7	Procedure	UGS-K7 Procedure - Pressure Test (Mechanical Integrity Test) Acceptance and Frequency 2021 12 02.docx	Appendix K, Practice 7 – Mechanical Integrity Test Acceptance and Frequency

Organization of TD-4870M Effective February 1, 2022

Section	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022	RIMP Version 5
Well Integrity	S15	Procedure	UGS-S15 Procedure - Casing Inspection Logging and Data Assessments 2021 12 02.docx	Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments
Well Integrity	T16	Procedure	UGS-T16 Procedure - Temperature - Noise Logging and Data Review 2021 12 02.docx	Appendix T, Practice 16 - Annual Temperature / Noise Logging and Data Review
Well Integrity	U17	Procedure	UGS-U17 Procedure - Gamma Ray Neutron Logging 2021 12 02.docx	Appendix U, Practice 17 - Gamma Ray Neutron and RST Logging
Well Integrity	V18	Procedure	UGS-V18 Procedure - Cement Bond Evaluation LDK Final Review 2021 12 02.docx	Appendix V, Practice 18 - Cement Bond Evaluation
Well Integrity	Z	Procedure	UGS-Z Procedure - Well Integrity Testing Regime Process - Production Casing 2021 12 02.docx	Appendix Z, Well Integrity Testing Regime Process – Production Casing
Well Monitoring	11	Standard	UGS-11 Standard - Safety Valve Operation, Maintenance and Inspection 2021 12 02.docx	11. Safety Valve Operation, Maintenance and Inspection
Well Monitoring	12	Standard	UGS-12 Standard - Wellhead Valve Operation, Maintenance and Inspection 2021 12 2.docx	12. Wellhead (Christmas Tree) Valve Operation, Maintenance and Inspection
Well Monitoring	H4	Procedure	UGS-H4 Procedure - Sand Inspection 2021 12 02.docx	Appendix H, Practice 4 - Sand Inspection
Well Monitoring	J6	Procedure	UGS-J6 Procedure - Wellhead (Christmas Tree) Pressure Monitoring 2021 12 02.docx	Appendix J, Practice 6 – Wellhead (Christmas Tree) Pressure Monitoring
Well Monitoring	L8	Procedure	UGS-L8 Procedure - Annular Pressure and Gas Sampling Monitoring 2021 12 02.docx	Appendix L, Practice 8 - Annular Pressure and Gas Sampling Monitoring

Organization of TD-4870M Effective February 1, 2022

Section	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022	RIMP Version 5
Well Monitoring	M9	Procedure	UGS-M9 Procedure - Individual Well Pressure and Performance Monitoring 2021 12 02.docx	Appendix M, Practice 9 - Individual Well Performance Monitoring
Well Monitoring	N10	Procedure	UGS-N10 Procedure - Wellhead Annuli Pressure Collection 2021 12 02.docx	Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring
Well Monitoring	O11	Procedure	UGS-O11 Procedure - Gas Sampling Observation and Storage Wells 2021 12 02 .docx	Appendix O, Practice 11 - Observation and Selected I/W Well Gas Sampling
Well Monitoring	Q13	Procedure	UGS-Q13 Procedure - Third Party Activities 2021 12 02.docx	Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties
Well Testing	R14	Procedure	UGS-R14 Procedure - Evaluation of Safety Valve Leak-by Testing 2021 12 02.docx	Appendix R, Practice 14 - Downhole Safety Valve (DHSV) Leak-by Testing
Well Workover	AC	Procedure	UGS-AC Procedure - Management of Change 2021 12 02.docx	Appendix AC, Gas Storage Asset Management - Change Control for Well Rework Process
Well Workover	AD	Procedure	UGS-AD Procedure - Rig Evacuation Procedure 2021 12 02.docx	Appendix AD, Rig Evacuation Procedure
Well Workover	AE	Standard	UGS-AE Standard - Safety and Environmental Plan - Well Entry Work 2021 12 02.docx	Appendix AE, PG&E Underground Storage Facility Drilling/Rework Safety and Environmental Plan
Well Workover	AF	Standard	UGS-AF Standard - Well Signage, Gas Storage Wells 2021 12 02.docx	Appendix AF, PG&E Underground Storage Facility Signage
Well Workover	AG	Procedure	UGS-AG Standard - Well Work 2021 12 02.docx	Appendix AG, Well Work
Well Workover	AH	Procedure	UGS-AH Procedure - Well Work Contractor Competency 2021 12 02.docx	Appendix AH, Well Work Contractor Competency

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Section	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022	RIMP Version 5
Well Workover	AI	Procedure	UGS-AI Procedure - Rathole Drilling Program 2021 12 02.docx	Appendix AI, Rathole Drilling Program
Well Workover	AJ	Procedure	UGS-AJ Procedure - Well Kill Program 2021 12 02.docx	Appendix AJ, Well Kill Program
Well Workover	AK	Procedure	UGS-AK Procedure - Well Bring-In 2021 12 02.docx	Appendix AK, Well Bring-In Procedure
Well Workover	AL	Procedure	UGS-AL Procedure - BOP Inspection 2021 12 02.docx	Appendix AL, BOP Inspection Process
Well Workover	AM - New	Procedure	UGS-AM Procedure - PGE Well Site Manager 2021 12 02.docx	WSM Procedure
Well Workover	AN - New	Standard	UGS-AN Standard - Well Control 2021 12 02.docx	Well Control

Table Mapping Underground Storage Risk and Integrity Management Plan, REV 5 to TD-4870M Effective February 1, 2022

RIMP Version 5	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022
01. Introduction	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
02. Target Audience	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
03. Regulatory Jurisdiction for Company Gas Storage Fields	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
04. Roles and Responsibilities	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
05. Flow of Plan Activities and Frequency of Plan Updates	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
06. UGS Integrity Management Process	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
07. Data Management	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
08. Reservoir Integrity	8	Standard	UGS-8 Standard - Reservoir Integrity Management 2021 12 2.docx
09. Mechanical Integrity of Wells	9	Standard	UGS-9 Standard - Mechanical Integrity of Wells 2021 12 2.docx
10. Casing Pressure Tests and Annulus Monitoring	10	Standard	UGS-10 Standard - Pressure Tests and Annulus Monitoring 2021 12 2.docx
11. Safety Valve Operation, Maintenance and Inspection	11	Standard	UGS-11 Standard - Safety Valve Operation, Maintenance and Inspection 2021 12 02.docx
12. Wellhead (Christmas Tree) Valve Operation, Maintenance and Inspection	12	Standard	UGS-12 Standard - Wellhead Valve Operation, Maintenance and Inspection 2021 12 2.docx
13. Corrosion Monitoring and Evaluation	13	Standard	UGS-13 Standard - Corrosion Monitoring and Evaluation 2021 12 2.docx
13. NEW	13F-New	Standard	UGS-13F Standard - PGE Fluids Management 2021 12 2.docx
14. Evaluation of Operational Factors for Wells and Attendant Facilities	14A	Standard	UGS-14A Standard - Evaluation of Operational Factors for Wells and Attendant Facilities 2021 12 2.docx
14.6 Relative Risk Ranking	14B	Standard	UGS-14B Standard - Well Risk Assessment and Relative Risk Ranking 2021 12 2.docx
14.6 Relative Risk Ranking - NEW	14C-New	Procedure	UGS-14C Procedure - Relative Risk Ranking of Wells 2021 12 2.docx

Table Mapping Underground Storage Risk and Integrity Management Plan, REV 5 to TD-4870M Effective February 1, 2022

RIMP Version 5	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022
15. Threat and Risk Management	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
16. Asset Management Plans	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
17. Prioritization of Risk Mitigation and Control Efforts	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
18. Blank	1 - NEW	Standard	Non Storage Wells (Idle, Gas, and Oil Wells) UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
19. Abnormal Operating Conditions	19	Procedure	UGS-19 Procedure - Abnormal Operating Conditions 2021 12 2.docx
20. Emergency Response / Emergency Preparedness	20	Standard	UGS-20 Standard - Emergency Response - Emergency Preparedness 2021 12 2.docx
21. Security	21	Standard	UGS-21 Standard - Security 2021 12 2.docx
22. Change Control	22	Standard	UGS-22 Standard - Management of Change 2021 12 2.docx
23. Communication Plan	23	Procedure	UGS-23 Procedure - Quarterly and Monthly Reporting 2021 12 2.docx
24. Records	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
25. Blank	1 - NEW	Standard	Gas Storage Well Need and Usefulness and Decommission (Plug and Abandon) UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
26. Internal Auditing	26	Standard	UGS-26 Standard - Internal Auditing 2021 12 2.docx
27. Compliance Requirement / Regulatory Commitment	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
28. Document Contacts	In all docs	In all docs	In all new standalone documents
29. Revision Notes / Change Log	In all docs	In all docs	In all new standalone documents
Appendix A, Well Logging Criteria for New Wells	9	Standard	Appendix UGS-9 Standard - Mechanical Integrity of Wells 2021 12 2.docx
Appendix B, Additional Investigations	B	Procedure	UGS-B Procedure - Additional Investigations 2021 12 02.docx
Appendix C, Casing Inspection Survey Frequency Decision Tree	C	Procedure	UGS-C Procedure - Casing Inspection Survey Frequency Decision Tree 2021 12 02.docx

Table Mapping Underground Storage Risk and Integrity Management Plan, REV 5 to TD-4870M Effective February 1, 2022

RIMP Version 5	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022
Appendix D, Remedial Options and Decision Tree	D	Standard	UGS-D Standard - Remedial Options and Decision Tree 2021 12 02.docx
Appendix E - Practice 1 Design and Specifications for Construction of Natural Gas Storage Wells	E	Standard	UGS-E Standard - Design and Specifications for Construction of Natural Gas Storage Wells 2021 12 02.docx
Appendix E, Practice 1A - Wellhead Equipment Design Standard	E1A	Standard	UGS-E1A Standard - Wellhead Equipment Design 2021 12 02.docx
Appendix E, Practice 1B – Tubular Design Standard	E1B	Standard	UGS-E1B Standard - Tubular Equipment Design 2021 12 02.docx
Appendix E, Practice 1C – Cementing Standard	E1C	Standard	UGS-E1C Standard - Cementing 2021 12 02.docx
Appendix E, Practice 1D – Well Abandonment Standard	E1D	Standard	UGS-E1D Standard - Well Abandonment 2021 12 02 .docx
Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics	F2	Procedure	UGS-F2 Procedure - Creating and Updating Storage Wellbore Schematics 2021 12 02.docx
Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams	G3	Procedure	UGS-G3 Procedure - Creating and Updating Storage Wellhead Diagrams 2021 12 02.docx
Appendix H, Practice 4 - Sand Inspection	H4	Procedure	UGS-H4 Procedure - Sand Inspection 2021 12 02.docx
Appendix I, Practice 5 - Uphole Safety Valve (UHSV) Leak-by Test Procedures	I	Guidance	Guidance Document Future
Appendix J, Practice 6 – Wellhead (Christmas Tree) Pressure Monitoring	J6	Procedure	UGS-J6 Procedure - Wellhead (Christmas Tree) Pressure Monitoring 2021 12 02.docx

Table Mapping Underground Storage Risk and Integrity Management Plan, REV 5 to TD-4870M Effective February 1, 2022

RIMP Version 5	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022
Appendix K, Practice 7 – Mechanical Integrity Test Acceptance and Frequency	K7	Procedure	UGS-K7 Procedure - Pressure Test (Mechanical Integrity Test) Acceptance and Frequency 2021 12 02.docx
Appendix L, Practice 8 - Annular Pressure and Gas Sampling Monitoring	L8	Procedure	UGS-L8 Procedure - Annular Pressure and Gas Sampling Monitoring 2021 12 02.docx
Appendix M, Practice 9 - Individual Well Performance Monitoring	M9	Procedure	UGS-M9 Procedure - Individual Well Pressure and Performance Monitoring 2021 12 02.docx
Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring	N10	Procedure	UGS-N10 Procedure - Wellhead Annuli Pressure Collection 2021 12 02.docx
Appendix O, Practice 11 - Observation and Selected I/W Well Gas Sampling	O11	Procedure	UGS-O11 Procedure - Gas Sampling Observation and Storage Wells 2021 12 02 .docx
Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification	P12	Procedure	UGS-P12 Procedure - Inventory Verification (Pressure Hysteresis and Semi-annual SI Testing) 2021 12 02.docx
Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties	Q13	Procedure	UGS-Q13 Procedure - Third Party Activities 2021 12 02.docx
Appendix R, Practice 14 - Downhole Safety Valve (DHSV) Leak-by Testing	R14	Procedure	UGS-R14 Procedure - Evaluation of Safety Valve Leak-by Testing 2021 12 02.docx
Appendix R-FXN, Practice 14A - Downhole Safety Valve (DHSV) & Uphole Safety Valve(UHSV) Function Testing McDonald Island Station	R-FXN	Guidance	Guidance Document Future

Table Mapping Underground Storage Risk and Integrity Management Plan, REV 5 to TD-4870M Effective February 1, 2022

RIMP Version 5	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022
Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments	S15	Procedure	UGS-S15 Procedure - Casing Inspection Logging and Data Assessments 2021 12 02.docx
Appendix T, Practice 16 - Annual Temperature / Noise Logging and Data Review	T16	Procedure	UGS-T16 Procedure - Temperature - Noise Logging and Data Review 2021 12 02.docx
Appendix U, Practice 17 - Gamma Ray Neutron and RST Logging	U17	Procedure	UGS-U17 Procedure - Gamma Ray Neutron Logging 2021 12 02.docx
Appendix V, Practice 18 - Cement Bond Evaluation	V18	Procedure	UGS-V18 Procedure - Cement Bond Evaluation LDK Final Review 2021 12 02.docx
Appendix W, Glossary of Acronyms and Abbreviations	In all docs	In all docs	Contained in standalone documents as needed
Appendix X, Mitigations	1	Standard	Appendix UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
Appendix Y, Production Fluid Facility Capacity Tables	Eliminated	Eliminated	Eliminated
Appendix Z, Well Integrity Testing Regime Process – Production Casing	Z	Procedure	UGS-Z Procedure - Well Integrity Testing Regime Process - Production Casing 2021 12 02.docx
Appendix AA, Records Inventory	1	Standard	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx
Appendix AB, Guidance Document Reference	Eliminated	Eliminated	Eliminated
Appendix AC, Gas Storage Asset Management - Change Control for Well Rework Process	AC	Procedure	UGS-AC Procedure - Management of Change 2021 12 02.docx
Appendix AD, Rig Evacuation Procedure	AD	Procedure	UGS-AD Procedure - Rig Evacuation Procedure 2021 12 02.docx
Appendix AE, PG&E Underground Storage Facility Drilling/Rework Safety and Environmental Plan	AE	Standard	UGS-AE Standard - Safety and Environmental Plan - Well Entry Work 2021 12 02.docx

Table Mapping Underground Storage Risk and Integrity Management Plan, REV 5 to TD-4870M Effective February 1, 2022

RIMP Version 5	TD-4870M Document Number	Document Type	TD-4870M Effective February 1, 2022
Appendix AF, PG&E Underground Storage Facility Signage	AF	Standard	UGS-AF Standard - Well Signage, Gas Storage Wells 2021 12 02.docx
Appendix AG, Well Work	AG	Procedure	UGS-AG Standard - Well Work 2021 12 02.docx
Appendix AH, Well Work Contractor Competency	AH	Procedure	UGS-AH Procedure - Well Work Contractor Competency 2021 12 02.docx
Appendix AI, Rathole Drilling Program	AI	Procedure	UGS-AI Procedure - Rathole Drilling Program 2021 12 02.docx
Appendix AJ, Well Kill Program	AJ	Procedure	UGS-AJ Procedure - Well Kill Program 2021 12 02.docx
Appendix AK, Well Bring-In Procedure	AK	Procedure	UGS-AK Procedure - Well Bring-In 2021 12 02.docx
Appendix AL, BOP Inspection Process	AL	Procedure	UGS-AL Procedure - BOP Inspection 2021 12 02.docx
Appendix AM - Blank	AM - New	Procedure	UGS-AM Procedure - PGE Well Site Manager 2021 12 02.docx
Appendix AN - Blank	AN - New	Standard	UGS-AN Standard - Well Control 2021 12 02.docx

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
UGS-1-S	Standard (0)	UGS-1 Standard - Storage Integrity Management 2021 12 2.docx	Combined and converted Revision 5, Sections 1-7, 15, 16, 17, and Appendix X, and added new sections into Standalone Standard: • Gas Storage Well Need and Useful and Decommissioning and • Non-Storage Wells (Idle, Gas, and Oil Wells) • Record Inventory list shall be maintained
UGS-8-S	Standard (0)	UGS-8 Standard - Reservoir Integrity Management 2021 12 2.docx	Converted Revision 5, Section 08 - Reservoir Integrity into Standalone Standard
UGS-9-S	Standard (0)	UGS-9 Standard - Mechanical Integrity of Wells 2021 12 2.docx	Converted Revision 5, Section 09 - Mechanical Integrity of Wells and Appendix A, Well Logging Criteria for New Wells into Standalone Standard • Annually RE and Corrosion should coordinate and communicate and provide join summary on the cathodic protection system to protect wells
UGS-10-S	Standard (0)	UGS-10 Standard - Pressure Tests and Annulus Monitoring 2021 12 2.docx	Converted Revision 5, 10. Casing Pressure Tests and Annulus Monitoring into Standalone Standard • New section on annulus and data collection and system • Well Annular Monitoring System and Response plan requirements • Revisions on annular monitoring of all annuli
UGS-11-S	Standard (0)	UGS-11 Standard - Safety Valve Operation, Maintenance, and Inspection 2021 12 02.docx	Converted Revision 5, 11. Safety Valve Operation, Maintenance, and Inspection into Standalone Standard • Incorporate regulatory frequency and 48-hour testing notification

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
UGS-12-S	Standard (0)	UGS-12 Standard - Wellhead Valve Operation, Maintenance, and Inspection 2021 12 2.docx	Converted Revision 5, 12. Wellhead (Christmas Tree) Valve Operation, Maintenance, and Inspection into Standalone Standard
UGS-13-S	Standard (0)	UGS-13 Standard - Corrosion Monitoring and Evaluation 2021 12 2.docx	Converted Revision 5, 13. Corrosion Monitoring and Evaluation into Standalone Standard
UGS-13F-S - New	Standard (0)	UGS-13F Standard - PGE Fluids Management 2021 12 2.docx	New Standard created on Fluids Control and Management into Standalone Standard
UGS-14A-S	Standard (0)	UGS-14A Standard - Evaluation of Operational Factors for Wells and Attendant Facilities 2021 12 2.docx	Converted Revision 5, 14. Evaluation of Operational Factors for Wells and Attendant Facilities into Standalone Standard
UGS-14B-S	Standard (0)	UGS-14B Standard - Well Risk Assessment and Relative Risk Ranking 2021 12 2.docx	Converted Revision 5, 14.6 Relative Risk Ranking into Standalone Standard • Provides methodology requirements for well-by-well risk assessment
UGS-14C-P - New	Procedure (0)	UGS-14C Procedure - Relative Risk Ranking of Wells 2021 12 2.docx	Converted Revision 5, 14.6 Relative Risk Ranking into Standalone Procedure • Procedure for update of relative risk ranking and databases • Publication of Relative Risk Model by July 31 and January 31

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
UGS-19-P	Procedure (0)	UGS-19 Procedure - Abnormal Operating Conditions 2021 12 2.docx	Converted Revision 5, 19. Abnormal Operating Conditions into Standalone Procedure • Documenting for trending and assessment • AOC's include events found in monitoring data sources
UGS-20-S	Standard (0)	UGS-20 Standard - Emergency Response - Emergency Preparedness 2021 12 2.docx	Converted Revision 5, 20. Emergency Response / Emergency Preparedness into Standalone Standard
UGS-21-S	Standard (0)	UGS-21 Standard - Security 2021 12 2.docx	Converted Revision 5, 21. Security into Standalone Standard
UGS-22-S	Standard (0)	UGS-22 Standard - Management of Change 2021 12 2.docx	Converted Revision 5, 22. Change Control into Standalone Standard • Include monitoring of AOC's and data sources • Table 1 – Data Sources to monitor included.
UGS-23-S	Standard (0)	UGS-23 Standard - Communication 2021 12 2.docx	Converted Revision 5, 23. Communication into Standalone Standard • Table 1 – Internal and Table 2 – External include identifying notification and reports for various procedures and standards
UGS-23-P - New	Procedure (0)	UGS-23 Procedure - Quarterly and Monthly Reporting 2021 12 2.docx	Converted Revision 5, 23. Communication Plan into Standalone Procedure

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
UGS-26-S	Standard (0)	UGS-26 Standard - Internal Auditing 2021 12 2.docx	Converted Revision 5, 26. Internal Auditing into Standalone Standard
UGS-AC-P	Procedure (0)	UGS-AC Procedure - Management of Change 2021 12 02.docx	Converted Revision 5, Appendix AC, Gas Storage Asset Management - Change Control for Well Rework Process • Streamline of procedure
UGS-AD-P	Procedure (0)	UGS-AD Procedure - Rig Evacuation Procedure 2021 12 02.docx	Converted Revision 5, Appendix AD, Rig Evacuation Procedure into Standalone Procedure • Outline's requirements and need for review
UGS-AE-S	Standard (0)	UGS-AE Standard - Safety and Environmental Plan - Well Entry Work 2021 12 02.docx	Converted Revision 5, Appendix AE, PG&E Underground Storage Facility Drilling/Rework Safety and Environmental Plan into Standalone Standard • Outline's requirements and need for review
UGS-AF-S	Standard (0)	UGS-AF Standard - Well Signage, Gas Storage Wells 2021 12 02.docx	Converted Revision 5, Appendix AF, PG&E Underground Storage Facility Signage into Standalone Standard
UGS-AG-S	Standard (0)	UGS-AG Standard - Well Work 2021 12 02.docx	Converted Revision 5, Appendix AG, Well Work into Standalone Standard. • Outline's requirements and need for review • Communication on flare stack placement

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
UGS-AH-P	Procedure (0)	UGS-AH Procedure - Well Work Contractor Competency 2021 12 02.docx	Converted Revision 5, Appendix AH, Well Work Contractor Competency into Standalone Procedure • Outline's requirements and need for review
UGS-AI-P	Procedure (0)	UGS-AI Procedure - Rathole Drilling Program 2021 12 02.docx	Converted Revision 5, Appendix AI, Rathole Drilling Program into Standalone Procedure • Outline's requirements and need for review
UGS-AJ-P	Procedure (0)	UGS-AJ Procedure - Well Kill Program 2021 12 02.docx	Converted Revision 5, Appendix AJ, Well Kill Program into Standalone Procedure • Outline's requirements and need for review • Communication on flare stack placement
UGS-AK-P	Procedure (0)	UGS-AK Procedure - Well Bring-In 2021 12 02.docx	Converted Revision 5, Appendix AK, Well Bring-In Procedure into Standalone Procedure • Outline's requirements and need for review • Communication on flare stack placement
UGS-AL-P	Procedure (0)	UGS-AL Procedure - BOP Inspection 2021 12 02.docx	Converted Revision 5, Appendix AL, BOP Inspection Process into Standalone Procedure • Outline's requirements and need for review
UGS-AM-P – New	Procedure (0)	UGS-AM Procedure - PGE Well Site Manager 2021 12 02.docx	New Procedure, Well Site Manager (WSM) into Standalone Procedure

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
UGS-AN-S – New	Standard (0)	UGS-AN Standard - Well Control 2021 12 02.docx	New Standard, Well Control into Standalone Standard
UGS-B-P	Procedure (0)	UGS-B Procedure - Additional Investigations 2021 12 02.docx	Converted Revision 5, Appendix B, Additional Investigations into Standalone Procedure
UGS-C-P	Procedure (0)	UGS-C Procedure - Casing Inspection Survey Frequency Decision Tree 2021 12 02.docx	Converted Revision 5, Appendix C, Casing Inspection Survey Frequency Decision Tree into Standalone Procedure
UGS-D-S	Standard (0)	UGS-D Standard - Remedial Options and Decision Tree 2021 12 02.docx	Converted Revision 5, Appendix D, Remedial Options and Decision Tree into Standalone Standard
UGS-E-S	Standard (0)	UGS-E Standard - Design and Specifications for Construction of Natural Gas Storage Wells 2021 12 02.docx	Converted Revision 5, Appendix E - Practice 1 Design and Specifications for Construction of Natural Gas Storage Wells into Standalone Standard
UGS-E1A-S	Standard (0)	UGS-E1A Standard - Wellhead Equipment Design 2021 12 02.docx	Converted Revision 5, Appendix E, Practice 1A - Wellhead Equipment Design Standard into Standalone Standard

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
UGS-E1B-S	Standard (0)	UGS-E1B Standard - Tubular Equipment Design 2021 12 02.docx	Converted Revision 5, Appendix E, Practice 1B – Tubular Design Standard into Standalone Standard
UGS-E1C-S	Standard (0)	UGS-E1C Standard - Cementing 2021 12 02.docx	Converted Revision 5, Appendix E, Practice 1C – Cementing Standard into Standalone Standard
UGS-E1D-S	Standard (0)	UGS-E1D Standard - Well Abandonment 2021 12 02 .docx	Converted Revision 5, Appendix E, Practice 1D – Well Abandonment Standard into Standalone Standard
UGS-F2-P	Procedure (0)	UGS-F2 Procedure - Creating and Updating Storage Wellbore Schematics 2021 12 02.docx	Converted Revision 5, Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics into Standalone Procedure
UGS-G3-P	Procedure (0)	UGS-G3 Procedure - Creating and Updating Storage Wellhead Diagrams 2021 12 02.docx	Converted Revision 5, Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams into Standalone Procedure
UGS-H4-P	Procedure (0)	UGS-H4 Procedure - Sand Inspection 2021 12 02.docx	Appendix H, Practice 4 - Sand Inspection into Standalone Procedure

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
UGS-J6-P	Procedure (0)	UGS-J6 Procedure - Wellhead (Christmas Tree) Pressure Monitoring 2021 12 02.docx	Appendix J, Practice 6 – Wellhead (Christmas Tree) Pressure Monitoring into Standalone Procedure
UGS-K7-P	Procedure (0)	UGS-K7 Procedure - Pressure Test (Mechanical Integrity Test) Acceptance and Frequency 2021 12 02.docx	Appendix K, Practice 7 – Mechanical Integrity Test Acceptance and Frequency into Standalone Procedure
UGS-L8-P	Procedure (0)	UGS-L8 Procedure - Annular Pressure and Gas Sampling Monitoring 2021 12 02.docx	Appendix L, Practice 8 - Annular Pressure and Gas Sampling Monitoring into Standalone Procedure • Revisions to align with regulatory requirements • Change 120 psig surface casing threshold to 100 psig
UGS-M9-P	Procedure (0)	UGS-M9 Procedure - Individual Well Pressure and Performance Monitoring 2021 12 02.docx	Appendix M, Practice 9 - Individual Well Performance Monitoring into Standalone Procedure
UGS-N10-P	Procedure (0)	UGS-N10 Procedure - Wellhead Annuli Pressure Collection 2021 12 02.docx	Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring into Standalone Procedure • Outline procedure for collection, data review and validation
UGS-O11-P	Procedure (0)	UGS-O11 Procedure - Gas Sampling Observation and Storage Wells 2021 12 02 .docx	Appendix O, Practice 11 - Observation and Selected I/W Well Gas Sampling into Standalone Procedure

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
UGS-P12-P	Procedure (0)	UGS-P12 Procedure - Inventory Verification (Pressure Hysteresis and Semi-annual SI Testing) 2021 12 02.docx	Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification into Standalone Procedure
UGS-Q13-P	Procedure (0)	UGS-Q13 Procedure - Third Party Activities 2021 12 02.docx	Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties into Standalone Procedure • Frequency of survey and monitoring corrected too quarterly
UGS-R14-P	Procedure (0)	UGS-R14 Procedure - Evaluation of Safety Valve Leak-by Testing 2021 12 02.docx	Appendix R, Practice 14 - Downhole Safety Valve (DHSV) Leak-by Testing into Standalone Procedure
UGS-S15-P	Procedure (0)	UGS-S15 Procedure - Casing Inspection Logging and Data Assessments 2021 12 02.docx	Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments into Standalone Procedure
UGS-T16-P	Procedure (0)	UGS-T16 Procedure - Temperature - Noise Logging and Data Review 2021 12 02.docx	Appendix T, Practice 16 - Annual Temperature / Noise Logging and Data Review into Standalone Procedure
UGS-U17-P	Procedure (0)	UGS-U17 Procedure - Gamma Ray Neutron Logging 2021 12 02.docx	Appendix U, Practice 17 - Gamma Ray Neutron and RST Logging into Standalone Procedure

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
UGS-V18-P	Procedure (0)	UGS-V18 Procedure - Cement Bond Evaluation LDK Final Review 2021 12 02.docx	Appendix V, Practice 18 - Cement Bond Evaluation into Standalone Procedure
UGS-Z-P	Procedure (0)	UGS-Z Procedure - Well Integrity Testing Regime Process - Production Casing 2021 12 02.docx	Appendix Z, Well Integrity Testing Regime Process – Production Casing into Standalone Procedure
In all docs	In all docs	Contained in standalone documents as needed	Appendix W, Glossary of Acronyms and Abbreviations
In all docs	In all docs	Contained in standalone documents as needed	28. Document Contacts
In all docs	In all docs	Contained in standalone documents as needed	29. Revision Notes / Change Log
		Future Guidance Document	Appendix I, Practice 5 - Uphole Safety Valve (UHSV) Leak-by Test Procedures

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TD-4870M Document Number	Doc Type and (Revision #)	TD-4870M Effective February 1, 2022	Notes
		Future Guidance Document	Appendix R-FXN, Practice 14A - Downhole Safety Valve (DHSV) & Uphole Safety Valve (UHSV) Function Testing McDonald Island Station
		Future Guidance Document	Revision 5, Appendix AA – Records Inventory
Eliminated	Eliminated	Eliminated	Revision 5, Appendix AB, Guidance Document Reference Removed
Eliminated	Eliminated	Eliminated	Appendix Y, Production Fluid Facility Capacity Tables Removed

Underground Storage Risk and Integrity Management

SUMMARY

The risk and integrity management plan for gas storage assets has been developed to protect the public, environment, and company and contract personnel, to protect the assets, and to ensure compliance with the regulations listed in Section 3.

The plan consists of a set of prevention measures set forth in standards and procedures listed in Appendix 1 of this standard to monitor, assess, and address asset integrity.

TARGET AUDIENCE

Employees in departments involved with all aspects of gas storage operations such as

- Gas Storage Asset Management (GSAM)
- Gas Pipeline Operations & Maintenance (GPOM)
- Station Services
- Corrosion Engineering
- Pipeline Services
- Transmission Integrity Management Program
- Leak Management

This plan and the companion documents reside in the following locations, to ensure accessibility to the personnel listed above.

Document	Location
This plan and guidance documents	Gas Operations Technical Information Library
Guidance documents published by the Gas Operations Guidance Documents and Engineering Services Department (or the department successor)	Gas Operations Technical Information Library
Companion guidance documents developed or adopted by GSAM	GSAM shared drive and Reservoir Engineering (RE) group SharePoint

Underground Storage Risk and Integrity Management

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SUBSECTION TITLE PAGE

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Underground Storage Risk and Integrity Management

REQUIREMENTS

1. Introduction

Pacific Gas and Electric Company (PG&E) underground natural gas storage fields help provide customers with safe, reliable, and affordable gas throughout the year and provide peak day gas supply during high-demand periods. The gas in the storage fields belongs to PG&E and customers and is injected, stored, and withdrawn as required.

This Underground Storage Risk and Integrity Management Plan (the “Plan” or “IMP”) has been developed to provide guidance to personnel involved in all aspects of storage field operations to protect the public, environment, contract personnel, and company personnel and assets. This guidance is in compliance with the federal and California regulations presented below in Section 3,

The Plan is contained in a number of guidance documents, and is designed to support PG&E in its activities to establish and maintain the functional integrity of storage wells and reservoirs as well as the prevention and mitigation (P&M) activities to manage the associated risk and meet the requirement for an operator to develop and follow procedures (Section 11 – Procedures and Training, API 1171 RP Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifers Reservoirs) These activities are founded on PG&E SME experience, and industry recommended practices and applicable to the specific work to be performed. Principles of process safety have also been incorporated into the practices as identified in the Plan.

Throughout this library, the applicable codes are cited as compliance requirements that are adopted in this IMP library. Refer to Section 3 below for a more detailed discussion.

Implementation of this plan supports a variety of risk management activities by PG&E: identification of potential threats and hazards to reservoir and well integrity; assessment of risks based on potential severity and estimated likelihood of occurrence of each threat; identification of the preventive and monitoring processes employed to mitigate the risk associated with each threat; and implementation of a process for periodic review and reevaluation of the risk assessment and prevention protocols. The plan is both a broadly applicable level across assets groups and at site- and asset-specific level. Individual storage facility work plans and procedures outline compliance of well assets to CCR 1726.5 are Standard 14A, Standard 14B, and Procedure 14C – Section 1:

The products of Standard 14B and Procedure 14C are the well-by-well risk model and implementation plans for each field. The risk model and the implementation plan are living documents and are updated as needed based on continuous evaluation data received as part of the P&M measures outlined within this plan.

As part of integrity management, the Plan provides practices for assessing existing reservoir and well integrity, and for monitoring of existing reservoir and well operations to demonstrate and verify that the gas stored in the facility remains contained in the reservoir and protected from undesired reservoir gas migration or breaches in the wells.

The Plan does not address requirements for new storage field design and construction, expansion of existing storage capacity, and commissioning of new or expanded capacity.

The Plan does not replace or restrict PG&E's compliance with any specific requirements applicable to pipelines and associated facilities pursuant to the United States Code of Federal Regulations (CFR) Parts 190-199 of Title 49 and California Public Utilities Commission General Order No. 112.

The Plan has been developed to reduce the human factor risk element in the design, operation and maintenance of the assets. Targeted audiences, roles, and responsibilities are identified in Section 2 and 3. Procedure 19 Abnormal Operating Conditions and Standard 22 Management of Change provide guidance for personnel operating the facilities to address changes in the operations and assess the threats and risks associated with human factors. Procedures have been developed to address the complexity of a task, experience and expertise of employees performing tasks, and provide procedures/processes to ensure repeatable review and assessment of the storage threat and risks (CCR 1726.3(d)(12)).

2. Training (CCR 1726.3 (d) (13)

Initial and refresher training are provided as needed to the identified target audience to ensure that personnel understand and adhere to the current published version of this Plan.

3. Regulatory Jurisdiction for Company Gas Storage Fields

Initial investments in and continued operation of the Company natural gas storage fields are subject to the jurisdiction of California Public Utility Commission (CPUC). The CPUC has issued Certificates of Public Convenience and Necessity for each PG&E storage facility.

Underground Storage Risk and Integrity Management

The policies and guidance in the IMP library are in compliance with

- The Pipeline and Hazardous Materials Safety Administration (PHMSA) Final Rule issued by PHMSA and incorporates by reference,
- American Petroleum Institute (API) Recommended Practice (API RP) 1171 Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, and
- California Public Resources Code provide the authority by which CalGEM regulates gas storage wells (Sections 3106, 3180, 3181, 3220, and 3403.5) pursuant California Code of Regulations Title 14 Chapter 3 Subchapter 1, Article 5, Section 1726. Other provisions of the PRC and CCR are applicable to storage and may not be referenced in this document.

Throughout this document, the following codes are cited as compliance requirements that are adopted in this IMP, to clarify the specific codes that are addressed by guidance in the IMP document library.

- PHMSA
- API RP 1171
- CalGEM CCR Title 14 Chapter 4, Subchapter 1, Article 5, Section 1726.

The Plan and previous versions pursuant to CCR 1726.3 (a) has been provided to CalGEM and the CPUC. The Plan is designed to be PG&E's central guidance document to maintain the functional integrity of storage wells and reservoirs as well as the prevention and mitigation (P&M) activities to manage the associated risk. These activities are founded on PG&E SME experience, and industry recommended practices and applicable to the specific work to be performed. Principles of process safety have also been incorporated into the practices as identified in the Plan.

In addition to the codes addressed above that are applicable to wells and storage fields, PG&E applies the Transmission Integrity Management Program (TIMP) to all transmission pipe, including pipe operating within storage fields meeting the requirements of 49 CFR part 192 Subpart O. This includes High Consequence Area (HCA) analysis, threat identification and risk assessment on all transmission pipe on an annual basis. For HCAs, assessments and reassessments of the identified threats are performed within the code-prescribed timeframes and may include External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA), Stress Corrosion Cracking Direct Assessment (SCCDA), In-Line Inspection (ILI), and

Hydrostatic Testing. In addition, PG&E is currently considering a threat assessment program to assess non-HCA pipe in exceedance of minimum code requirements

4. Roles and Responsibilities

The stakeholders who are involved in the Plan are listed in the following table.

Table 1: Stakeholders

Department	Responsibilities Related to Storage Assets
Gas Storage Asset Family Owner	• Understand the condition of storage assets • Understand the risks to storage assets • Develop and implement asset risk reduction strategies • Develop long term financial plan • Ensure that training is in place for PG&E and third-party personnel who are involved in storage assets
Gas Pipeline Operations & Maintenance (GPOM)	• Operate the storage assets • Perform preventive and corrective maintenance on equipment, and ensure personnel receive training as appropriate. • Provide guidance and coordinate leak survey of storage facilities
Leak Survey Dept	• Conduct leak surveys. • Provide training to leak survey personnel.
Reservoir Engineering	• Maintain integrity of wells and reservoirs within storage facilities • Develop, deliver and receive training on prevention and mitigation measures to manage reservoir and equipment risks
Station Services/Facility Integrity Management	• Maintain integrity of pipe and surface equipment within Storage facilities
Corrosion Engineering	• Develop corrosion site specific plans for storage facilities • Ensure corrosion personnel receive training as appropriate.
Pipeline Services	• Maintain integrity for transmission pipe system including pipe near storage facilities • Ensure personnel receive training as appropriate.
Gas System Operations & Planning	• Manage inventory, deliverability capacity, and outage planning
Gas Emergency Preparedness	• Maintain the emergency response documentation and manage drills and exercises accordingly

Department	Responsibilities Related to Storage Assets
Transmission Integrity Management Program	• Identify threats, assess asset condition, and prioritize mitigation work for transmission pipe system including pipe near Storage facilities • Ensure personnel receive training as appropriate.

5. Frequency of Plan Updates

The Plan should be reviewed on an annual basis or when there is an actual or perceived change in risk. The Plan, however, will be reviewed on a annual frequency for the entire document (CCR 1726.3(a) requires not to exceed 3 years, but PHMSA requires annual).

Guidance document review and modifications may be performed to account for circumstances such as changes in operating conditions (e.g., well and reservoir integrity performance, the number and types of issues that are occurring), as well as other issues, hazards or threats, advancements in technology, regulatory changes, abnormal operating conditions or as experience dictates. Reviews may also be conducted based on internal audits of the work being done by storage personnel (ref Standard 26) to determine the adequacy and effectiveness of the procedures used in operation and maintenance of storage facilities.

Reviews of and changes to this plan and companion guidance documents published by GSAM shall be accomplished in a controlled manner in accordance with Procedure AC22, Management of Change, of this plan.

6. UGS Integrity Management Process

The following activities are performed to demonstrate and verify reservoir and well[1] (active and Idle status) integrity, and safety, asset, environmental and financial risks are identified and prevented or effectively mitigated (CCR 1726.3 (b)):

The following standards address activities that are performed to demonstrate that stored gas will be confined to the approved reservoir and that risks of damage to life, health, property, the environment, or natural resources are identified and prevented or effectively mitigated.

- Record and Data Management (Section 8 of this standard)

[1] CCR Chapter 2, Article 5, 1726.1 defines a gas storage well which includes active or idle wells used primarily to inject or withdraw gas from an underground storage project

- Non-Storage Wells (Gas and Oil Wells) (Section 9 of this standard)
- Asset Threat and Risk Management (Section 10 of this standard)
- Standard 8, Reservoir Integrity Management
- Standard 9, Mechanical Integrity of Wells
- Standard 10, Casing Pressure Tests and Annulus Monitoring
- Standard 11, Safety Valve Operation, Maintenance and Inspection
- Standard 12, Wellhead (Christmas Tree) Valve Operation, Maintenance and Inspection
- Standard 13, Corrosion Monitoring and Evaluation
- Standard 13F, PG&E Fluids Management
- Standard 14A, Evaluation of Wells and Attendant Production Facilities
- Standard 14B, Well Risk Assessment and Relative Risk Ranking
- Standard 20, Emergency Response – Emergency Preparedness
- Standard 21, Security
- Standard 22, Management of Change
- Standard 23, Communication
- Standard 26, Internal Auditing
- Standard AF, Well Signage, Gas Storage Wells
- Standard E Design and Specifications for Construction on Natural Gas Storage Wells

7. Well Work

Work plans shall be created when performing drilling, rework, well kills and bring-in, wireline, slickline and logging operations, well testing and other well operations requiring well entry.

The following standards address activities that are performed to create work plans to identify, prevent, effectively mitigate, or reduce the risks of damage to life, health, property, the environment, or natural resources.

- Standard 10, Pressure Tests and Annulus Monitoring
- Standard 13F, PGE Fluids Management
- Standard 20 Emergency Response – Emergency Preparedness
- Standard 22, Management of Change
- Standard AF, Well Signage, Gas Storage Wells
- Standard E, Design and Specifications for Construction of Natural Gas Storage Well
- Standard E1A, Wellhead Equipment Design
- Standard E1B, Tubular Equipment Design
- Standard E1C, Cementing

- Standard E1D, Well Abandonment
- Standard AE, Safety and Environmental Plan – Well Entry Work
- Standard AF, Well Signage, Gas Storage Wells
- Standard AG, Well Work
- Standard AN, Well Control

8. Records and Data Management

Traceable, verifiable, and complete gas storage asset data is maintained in an accessible manner to support risk and asset management, asset operations and maintenance, and for regulatory inspection (CCR 1726.3 (c)(8) and CCR 1726.4.3).

8.1. Requirements for Records

Inspections, tests, patrols, or analyses shall be documented according to this plan, GOV-7101S, and documentation requirements in guidance documents used by PG&E outside of GSAM. This includes records that demonstrate compliance with PHMSA and CalGEM's regulations including training. All records are retained in accordance with the Enterprise Record Retention Schedule (ERRS) included in GOV-7101S (CCR 1726.4.3(c) and (d).

A Record Inventory list shall be maintained identifying the records (CCR 1726.4.3(b).

Refer to GSAM Standard 23 for the requirements for submittals to regulatory agencies.

Records retained shall include superseded procedures.

8.2. Records Storage

Records Inventory for GSAM are stored on the GSAM shared drive (CCR 1726.4.3(c)). Detailed organization is best understood by reviewing the shared drive directory tree system. This provides an overview of the system:

- Records specific to a storage field are stored in a subdirectory for that storage field.
- Records specific to a single well are stored by well number.
- Equipment manufacturer documentation such as drawings, manuals or procedures are stored in two locations
    - GSAM shared drive in the folder for the associated GSAM asset.
    - Gas Operations records system (Documentum), managed by EDRM.

Examples include documentation for wellhead manual valves, uphole safety valves and downhole safety valves.

- Management of change and abnormal operating condition documentation created by GSAM for well work (refer to Procedure AC and Procedure 19 of this plan).

MoC records for GSAM other than well work are retained by the Gas Operations Process Safety Department. Also, Refer to Procedure AC, Management of Change for Well Rework.

Records listed in the Records Inventory for other PG&E organizations are stored in hard copy and/or electronic form in systems maintained by those organizations.

In cases where GSAM is not in possession of the electronic source document, hardcopy records shall be scanned and stored in the appropriate folder in the GSAM shared drive. Examples include:

- Documents from regulatory agencies such as permits, audit results, etc.
- Management of change documentation (forms) that are filled in with handwriting (e.g., GSAM Field Change Control Form).
- Manufacturer foreign print files.

8.3. Obsolete Records

In general, all records are preserved for the life of the asset and archived if the asset is removed from service (CCR 1726.4.3(d)). Exceptions must be approved by the GSAM director as follows:

When an asset is removed from service permanently or if the asset owner identifies records that are no longer required for compliance, maintenance and operational, or business needs, the following must be performed:

1. Identify all copies of documents or records, electronic or hardcopy.
2. Present list of documents and/or records and obtain approval from asset owner (GSAM Director) to obsolete documents and/or records.
3. Once approval has been obtained, dispose of any hardcopies in secure PG&E record disposal bin or request approved shred services to securely dispose of record to ensure confidentiality of records is obtained.
4. If using an approved shredding provider, request signed records destruction form and scan copy of form. Add to appropriate GSAM shared drive.

5. Request other PG&E departments (e.g., GPOM) to obsolete drawings records if available.
6. Remove and delete electronic forms from the GSAM SharePoint

9. Non-Storage Wells (Idle[2], Gas, and Oil Wells[3])

9.1. Re-Classification of Gas Storage Wells

PG&E may through the determination of a CPUC proceeding convert natural gas storage wells[4] to non-storage wells in the decommissioning or operations of a gas storage field. Gas wells aid in the recovery of working and cushion gas that was used in storage operations. Converting of a gas storage well may require the filing of permits or other data submittals to the CPUC, CalGEM, or other agencies if change impacts tax assessments or fees to continue operation as a non-storage well.

9.2. Asset and Risk Management of Non-Storage Wells

PG&E integrity management teams shall investigate and understand the regulatory requirements for non-storage wells and complete a risk and asset assessments to determine which gas storage programs should continue to manage the asset and its associated risk.

All idle wells shall be tested pursuant to regulatory requirements

10. Asset, Threat and Risk Management (old IMP Sections 15 16 17))

The asset management plan (AMP) for storage assets and the Strategic Asset Management Plan (SAMP) for Gas Operations are the primary documents that address higher-level strategies and processes for asset and risk management. This section of this standard is a companion to these two AMPs and provides supplemental detail regarding the process and methodology used by GSAM to evaluate all potential threats, hazards and corresponding risks impacting storage wells and reservoirs (CCR 1726.3). Standard 1, Well Risk Assessment and Relative risk

[2] CCR Chapter 2, Article 5, 1760(n) defines an idle well

[3] (California Public Resources Code) PRC Division 3, Chapter 1, Article 1,CCR §3006, 3007, 3008 defines meaning of oil, gas, and well

[4] CCR Chapter 2, Article 5, 1726.1 defines a gas storage well.

Ranking provides guidance on well-by-by analysis and provides methodology defined in CCR 1726.3(c)(4).

10.1. Integrity and Asset Threat Classification (CCR 1726.3(c)(1) and (2))

The Gas Storage Asset Family uses API RP 1171 and monitors data sources (see Standard 22). Potential threats or hazards identified for the wells, reservoir, and surface from API RP 1171 Table 1 Potential Threats and Consequences. PHMSA regulations require the use of API RP 1171 which GSAM has incorporated to meet the requirements of CalGEMS. In addition to API 1171, GSAM identifies and compares threats as set forth in ASME B31.8S (refer to the Storage AMP) and shall include the following in the threat consideration.

- Asset Family Owner shall maintain a threat matrix that documents the data quality status of each threat and the status of the various primary prevention measures to address those threats.
- The threat matrix shall be maintained through an annual review by GSAM SMEs.
- The Storage AMP shall contain the threat matrix and discussion of ASME B31.8S threat categories and threats specific to the Storage AF.
- An inventory of data shall be maintained that is available for use in assessing risks.

Mitigations and prevention activities and their associated guidance documents for each threat to the storage asset types are listed in Appendix 1 of this standard for convenience to reader to understand the relationship.

10.1.1. Risk Identification and Evaluation

Threats shall be considered by GSAM SMEs in the identification and development of corresponding risks. SMEs assess each threat and each affected asset, incorporate their experience and applicable industry knowledge (see Standard 22), and develop consequences and probabilities that when combined define the risks associated with the assets.

Abnormal Operating Conditions should be reviewed to inform the risk identification and evaluation (see Procedure 19, Abnormal Operating Conditions).

These risks shall be incorporated into the GSAM well risk ranking model (ref GSAM Std 14B – Well Risk Assessment and Relative Risk Ranking).

Any applicable threat should be considered even if shortcomings exist in the availability of data. While no ASME B31.8S or API 1171 threats are excluded at this time, if it ever becomes appropriate to exclude any, this exclusion would be justified and documented in the supporting documentation for the threat matrix (refer to the Gas Storage AMP for threat matrix information)

PG&E is developing risk management models to support assessment of risks across the entire enterprise (refer to Section 9.1 above). GSAM provides storage asset risks as part of this effort and documents these risks in a risk register. These are presented in the asset management plan. However, the identification, assessment and management of storage asset risks is accomplished with risk process internal to GSAM, not the enterprise modeling work.

10.2. Risk Response – Development of Mitigation Programs (CCR 1726.3(c)(3) and (6))

GSAM shall develop mitigation programs and priorities based on the risk identification and evaluation. Mitigations shall be documented in the Threat Matrix. Development of mitigations should include review of API RP 1171 Table 2 Preventive and Mitigation Programs.

10.3. Risk Mitigation Reporting and Monitoring (Outputs and Documentation) (CCR 1726.3(c)(5) thru (9))

The processes described in this section contain risk management activities that are conducted on a formal, **annual cycle**, however, the risk process including risk monitoring, risk management, assessments of risk management program effectiveness and improvement to risk management in general is continuous. If during operations new threats or hazards are identified, or the impact of threats or hazards changes markedly, GSAM assesses the risk associated with new conditions and evaluates and prioritizes risk management options, metrics and monitoring frequencies in accordance with the risk assessment. These are key elements of maintaining the functional integrity of the storage operation.

The risk management process is reported, monitored and documented as described in the AMP. Review these elements of the AMP for details:

- Threat matrix
- Risk register
- Strategic objectives
- Risk management programs

PG&E's guidance document regarding records management and retention, GOV-7102S, "Enterprise Records and Information Management Standard", contains requirements that are applied to all GSAM records.

Refer to Section 8 of this Standard for records management.

11. Gas Storage Well Need and Usefulness and Decommission (Plug and Abandon)

Periodically PG&E should evaluate the need and usefulness of the gas storage well assets. The review should include an assessment for each well the following: A cost benefit analysis considering costs to operate, retrofit, plug and abandon, utilization as observation well, and a comparison of the well's relative risk ranking.

If a well based on the review is determined to no longer be needed for gas storage service, PG&E will then pursue decommissioning of the gas storage well.

Decommissioning of a gas storage well maybe required once it is not needed and useful. Decommissioning of a gas storage well is a permanent removal of the asset from service, but a closure of the wellbore, reclamation of the surface area, possible modifications to remaining facilities, and equipment removal. Decommissioning requires approval of the expenditure to decommission, of regulatory agencies as applicable, and notification to Capital Accounting to retire any remaining Plant Costs. Decommissioning is also a removal of an asset that support PG&E's storage services, approvals are required to take the well out of service by the appropriate Asset Family Owner, Gas Planning and Gas Control.

END of Instructions

12. ADMIN SECTIONS

12.1. DEFINITIONS

Refer to definitions in API 1171 and CalGEM regulations.

12.2. IMPLEMENTATION RESPONSIBILITIES

The reservoir family owner (or designee) will communicate this standard to personnel

12.3. GOVERNING DOCUMENT

This is the overarching standard for the library of guidance documents that comprise the integrity management plan for PG&E's gas storage assets.

12.4. COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Section 3 of this standard addresses these requirements, and by reference applies these requirements to all guidance documents in the integrity management plan library of guidance documents.

12.5. REFERENCE DOCUMENTS

Developmental References:

Past editions of the Gas Storage Asset Management Integrity Management Plan, and the standards set forth in Section 3 of this standard.

Supplemental References:

GOV-7101S, Enterprise Records and Information Management Standard

GSAM Procedure 23, Communications

12.6. APPENDICES

Appendix 1 – Mitigations

12.7. DOCUMENT RECISION

GSAM RIMP Rev 5

13. Document Approver

Larry Kennedy, Strategic Planning Chief, GSAM

14. Document Owner

Lucy Redmond, Director, GSAM.

15. Document Contact

Larry Kennedy, Strategic Planning Chief, GSAM.

Where?	What Changed?
Created from GSAM RIMP 3/28/19 and 6/20/20 editions	Content revisions to adopt to become the overarching standard for the integrity management plan. Adopted from IMP Sections 1-7, 15-17, 24, IMP Appendix X Mitigations, IMP Appendix AA Records Inventory is removed and a guidance document, IMP Appendix AB Guidance Document Reference is removed. Standards relating to non-storage wells and Well Work

16. Appendix 1 (X), Preventative and Mitigative Measures

The Table 1-1 displays the threats for asset type and the associated prevention measures to mitigate risk. It is provided in this standard as a convenience to reader to understand the relationship. Complete and updated information reader should consult Section 10.3 of this standard.

Table 1-1 – Preventative and Mitigative Measures and Guidance Documents

Asset Type: Well			
Threat(s)	**Preventative and Mitigative Measure(s)**	**Department(s)**	**Reference Document(s)**
Corrosion / Erosion, Manufacturing, Equipment	Cathodic Protection	Corrosion Engineering	• TD-4181P-201: Cathodic Protection Monitoring and Restoration • UGS-9, Standard Mechanical Integrity of Wells
	Guidance Documents (Drilling / Completion Design Standards and Process Safety Management)	Reservoir Engineering	• UGS-13F, Standard, PGE Fluids Management • UGS-13, Standard, Corrosion Monitoring and Evaluation • UGS–E1, Standard - Design and Specifications for Casing, Tubing, and Wellhead Equipment • UGS–E1A, Standard, Wellhead Equipment Design • UGS–E1B, Standard, Tubular Equipment Design • UGS–E1C, Standard, Cementing • UGS–E1D, Standard, Well Abandonment • UGS-AD, Procedure, Rig Evacuation Procedure • UGS-AE, Procedure, Safety and Environmental Plan • UGS-AF, Procedure, Well Signage, Gas Storage Wells • UGS-AG, Procedure, Well Work • UGS-AH Procedure, Well Work Contractor Competency • UGS-AI, Procedure, Rathole Drilling Program • UGS-AJ, Procedure, Well Kill Program • UGS-AK, Procedure, Well Bring In • UGS-AL, Procedure, BOP Inspection • UGS-AM, Procedure, PGE Well Site Manager • UGS-AN, Standard, Well Control

Underground Storage Risk and Integrity Management

Asset Type: Well			
Threat(s)	**Preventative and Mitigative Measure(s)**	**Department(s)**	**Reference Document(s)**
	Active and Plugged & Abandoned Well Evaluation (Well Schematics and Records)	Reservoir Engineering	• UGS-9, Standard, Mechanical Integrity of Wells • UGS-F2, Procedure - Creating and Updating Storage Wellbore Schematics • UGS-G3, Procedure - Creating and Updating Storage Wellhead Diagrams • UGS-E1D, Standard, Well Abandonment
	Casing Inspections (CBL, GRN, N/T, Caliper, Casing Inspection Tools)	Reservoir Engineering	• TD-4550P-20: Annual Gas Well Survey Procedures • UGS-B, Procedure, Additional Investigations • UGS-C, Procedure - Casing Inspection Survey Frequency Decision Tree • UGS-D Procedure, Remedial Options and Decision Tree • UGS-S15, Procedure - Casing Inspection Logging and Data Assessments • UGS-T16, Procedure - Temperature / Noise logging and Data Review • UGS-U17, Procedure - Gamma Ray Neutron and RST Logging • UGS-V18, Procedure - Cement Bond Evaluation • UGS-Z, Procedure – Well Integrity Testing Regime Process
Corrosion / Erosion, Manufacturing, Equipment	Monitor Well Performance Data	Reservoir Engineering	• UGS-13F, Standard, PGE Fluids Management • UGS-13, Standard, Corrosion Monitoring and Evaluation • UGS-H4, Procedure - Sand Inspection • UGS-M9, Procedure - Individual Well Performance Monitoring • UGS-N10, Procedure - Wellhead Annuli Pressure Monitoring
	Monitor Casing Annular Data	Reservoir Engineering	• UGS-13F, Standard, PGE Fluids Management • UGS-13, Standard, Corrosion Monitoring and Evaluation • UGS-L8, Procedure - Annular Pressure and Gas Sampling Monitoring • UGS-N10, Procedure - Wellhead Annuli Pressure Monitoring

Underground Storage Risk and Integrity Management

Asset Type: Well			
Threat(s)	**Preventative and Mitigative Measure(s)**	**Department(s)**	**Reference Document(s)**
	Pressure Test	Reservoir Engineering	• UGS-Z, Procedure - Well Integrity Testing Regime Process • UGS-10, Standard – Pressure Tests and Annulus Monitoring
	Leak Survey	Operations & Maintenance, Leak Survey	• Natural Gas Storage Facility Monitoring Plan for McDonald Island (published Oct 10, 2018) • Natural Gas Storage Facility Monitoring Plan for Los Medanos (published Oct 10, 2018) • Natural Gas Storage Facility Monitoring Plan for Pleasant Creek (published Oct 10, 2018)
Construction / Fabrication	Active and Plugged & Abandoned Well Evaluation (Well Schematics and Records)	Reservoir Engineering	• UGS-9, Standard, Mechanical Integrity of Wells • UGS-F2, Procedure - Creating and Updating Storage Wellbore Schematics • UGS-G3, Procedure - Creating and Updating Storage Wellhead Diagrams • UGS-E1D, Standard, Well Abandonment
	Guidance Documents (Drilling / Completion Design Standards and Process Safety Management)	Reservoir Engineering	• UGS-13F, Standard, PGE Fluids Management • UGS-13, Standard, Corrosion Monitoring and Evaluation • UGS–E1, Standard - Design and Specifications for Casing, Tubing, and Wellhead Equipment • UGS–E1A, Standard, Wellhead Equipment Design • UGS–E1B, Standard, Tubular Equipment Design • UGS–E1C, Standard, Cementing • UGS–E1D, Standard, Well Abandonment • UGS-AD, Procedure, Rig Evacuation Procedure • UGS-AE, Procedure, Safety and Environmental Plan • UGS-AF, Procedure, Well Signage, Gas Storage Wells • UGS-AG, Procedure, Well Work • UGS-AH Procedure, Well Work Contractor Competency • UGS-AI, Procedure, Rathole Drilling Program • UGS-AJ, Procedure, Well Kill Program • UGS-AK, Procedure, Well Bring In • UGS-AL, Procedure, BOP Inspection • UGS-AM, Procedure, PGE Well Site Manager • UGS-AN, Standard, Well Control • API RP 1171

Underground Storage Risk and Integrity Management

Asset Type: Well			
Threat(s)	**Preventative and Mitigative Measure(s)**	**Department(s)**	**Reference Document(s)**
Incorrect Operations (Operations & Maintenance)	Guidance Documents (Operating Standards	Operations & Maintenance, Station Services	• UGS-13F, Standard, PGE Fluids Management • Operating Procedures
	Operator Qualifications (OQ) Training and Development (Operations & Maintenance)	**OQ:** Gas Training & Implementation **Training and Dev:** Operations & Maintenance	• OQ: Utility Standard TD-4008S: Operator Qualification Program Requirements • UGS-AH Procedure, Well Work Contractor Competency • UGS-AM, Procedure, PGE Well Site Manager • Training and Dev: Apprentice Station Operator: Administrative Procedures Manual
Incorrect Operations (Well Intervention)	Active and P&A Well Evaluation (Well Schematics and records)	Reservoir Engineering	• UGS-F2, Procedure - Creating and Updating Storage Wellbore Schematics • UGS-G3, Procedure - Creating and Updating Storage Wellhead Diagrams
Incorrect Operations (Well Intervention)	Guidance Documents (Drilling / Completion Design Standards and Process Safety Management)	Reservoir Engineering	• UGS-13F, Standard, PGE Fluids Management • UGS-13, Standard, Corrosion Monitoring and Evaluation • UGS–E1, Standard - Design and Specifications for Casing, Tubing, and Wellhead Equipment • UGS–E1A, Standard, Wellhead Equipment Design • UGS–E1B, Standard, Tubular Equipment Design • UGS–E1C, Standard, Cementing • UGS–E1D, Standard, Well Abandonment • UGS-AD, Procedure, Rig Evacuation Procedure • UGS-AE, Procedure, Safety and Environmental Plan • UGS-AF, Procedure, Well Signage, Gas Storage Wells • UGS-AG, Procedure, Well Work • UGS-AH Procedure, Well Work Contractor Competency • UGS-AI, Procedure, Rathole Drilling Program • UGS-AJ, Procedure, Well Kill Program • UGS-AK, Procedure, Well Bring In • UGS-AL, Procedure, BOP Inspection • UGS-AM, Procedure, PGE Well Site Manager • UGS-AN, Standard, Well Control • API RP 1171

Underground Storage Risk and Integrity Management

Asset Type: Well			
Threat(s)	**Preventative and Mitigative Measure(s)**	**Department(s)**	**Reference Document(s)**
	OQ / Training and Development (Reservoir Engineering)	Reservoir Engineering	• Reservoir Engineer Competencies • Reservoir Specialist Competencies
	Blowout Prevention Systems	Reservoir Engineering	• API RP 1171 • UGS-13F, Standard, PGE Fluids Management • UGS-AL, Procedure, BOP Inspection • UGS-AM, Procedure, PGE Well Site Manager • UGS-AN, Standard, Well Control
Construction/ Fabrication, 1st, 2nd, 3rd Party Damage	Rules & Regulations	Reservoir Engineering	• CalGEM Regulations
	Location Design Requirements	Reservoir Engineering	• API RP 1171 • UGS–E1, Standard - Design and Specifications for Casing, Tubing, and Wellhead Equipment • UGS-AE, Procedure, Safety and Environmental Plan • UGS-AF, Procedure, Well Signage, Gas Storage Wells • UGS-AG, Procedure, Well Work
	Equipment Design Requirements	Reservoir Engineering	• UGS-E1, Standard - Design and Specifications for Casing, Tubing, and Wellhead Equipment • API RP 1171
	Land Rights	Land Rights, Reservoir Engineering	• UGS-Q13, Procedure - Third Party Activities
	Monitor Permit Activity	Reservoir Engineering	• UGS-Q13, Procedure - Third Party Activities

Underground Storage Risk and Integrity Management

Asset Type: Well			
Threat(s)	**Preventative and Mitigative Measure(s)**	**Department(s)**	**Reference Document(s)**
	Inspection During Construction	Reservoir Engineering	• UGS-13F, Standard, PGE Fluids Management • UGS-13, Standard, Corrosion Monitoring and Evaluation • UGS–E1, Standard - Design and Specifications for Casing, Tubing, and Wellhead Equipment • UGS–E1A, Standard, Wellhead Equipment Design • UGS–E1B, Standard, Tubular Equipment Design • UGS–E1C, Standard, Cementing • UGS–E1D, Standard, Well Abandonment • UGS-AE, Procedure, Safety and Environmental Plan • UGS-AF, Procedure, Well Signage, Gas Storage Wells • UGS-AG, Procedure, Well Work • UGS-AH Procedure, Well Work Contractor Competency • UGS-AL, Procedure, BOP Inspection • UGS-AM, Procedure, PGE Well Site Manager • UGS-AN, Standard, Well Control • API RP 1171
	Gas Sampling	Reservoir Engineering	• UGS-13F, Standard, PGE Fluids Management • UGS-13, Standard, Corrosion Monitoring and Evaluation • UGS-L8, Procedure - Annular Pressure and Gas Sampling Monitoring • UGS-O11, Procedure – Gas Sampling Observation and Storage Wells
Outside Forces (Geological)	Geological and Well Evaluation of Records	Reservoir Engineering	• Geologic and Seismic Review
	Protective Boundary	Reservoir Engineering	• API RP 1171
Outside Forces (Geological)	Land Rights	Land Rights, Reservoir Engineering	• UGS-Q13, Standard - Third Party
	Observation Wells	Reservoir Engineering	• UGS-L8, Standard - Annular Pressure and Gas Sampling Monitoring • UGS-N10, Standard - Wellhead Annuli Pressure Monitoring • UGS-O11, Standard – Gas Sampling Observation and Storage Wells
	Inventory Verification	Reservoir Engineering	• UGS-P12, Standard - Field Shut In Testing for Storage Gas Inventory Verification

Underground Storage Risk and Integrity Management

Asset Type: Well			
Threat(s)	**Preventative and Mitigative Measure(s)**	**Department(s)**	**Reference Document(s)**
Incorrect Operations	Guidance Documents (Design Standards for Fluids)	Reservoir Engineering	• API RP 1171 • UGS-13F, Standard, PGE Fluids Management • UGS-13, Standard, Corrosion Monitoring and Evaluation
	Gas Quality Studies	Reservoir Engineering	• API RP 1171 • UGS-13F, Standard, PGE Fluids Management • UGS-13, Standard, Corrosion Monitoring and Evaluation
	Fluid Compatibility Studies	Reservoir Engineering	• API RP 1171 • UGS-13F, Standard, PGE Fluids Management • UGS-13, Standard, Corrosion Monitoring and Evaluation
	Internal Corrosion Studies	Reservoir Engineering	• API RP 1171
1st, 2nd, 3rd Party Damage (Surface Encroachments)	Land Rights	Land Rights, Reservoir Engineering	• UGS-Q13, Standard - Third Party Activities
	Public Awareness & Damage Prevention	Public Awareness	• RMP-12: Pipeline Public Awareness Program
	Patrolling / Surveillance	Operations & Maintenance, Aerial Patrol, Leak Survey	• TD-4412P-07: Patrolling Gas Pipelines • Inspection and Leak Survey Protocol for Natural Gas Storage Facilities
1st, 2nd, 3rd Party Damage (Vandalism, Terrorism, Delayed Damage)	Physical Security Systems	Operations & Maintenance	• TD-4050S: Security Standard for Gas Operations • API RP 1171
1st, 2nd, 3rd Party Damage (Vandalism, Terrorism, Delayed Damage)	Public Awareness & Damage Prevention	Public Awareness	• RMP-12: Pipeline Public Awareness Program
	Patrolling / Surveillance	Operations & Maintenance, Aerial Patrol, Leak Survey	• TD-4412P-07: Patrolling Gas Pipelines • Inspection and Leak Survey Protocol for Natural Gas Storage Facilities

Underground Storage Risk and Integrity Management

Asset Type: Well			
Threat(s)	**Preventative and Mitigative Measure(s)**	**Department(s)**	**Reference Document(s)**
Weather & Outside Forces	Design Process	Station Services (Facility Design), Reservoir Engineering (Wellhead Design)	• Gas Standards & Specifications • Geologic and Seismic Review • Catastrophic Emergency Response Plan - Gas Annex: Stations and Gas Storage • UGS-E1, Standard - Design and Specifications for Casing, Tubing, and Wellhead Equipment
	Patrolling / Surveillance	Operations & Maintenance, Aerial Patrol, Leak Survey	• TD-4412P-07: Patrolling Gas Pipelines • Inspection and Leak Survey Protocol for Natural Gas Storage Facilities
	Remote Control Capabilities	Operations & Maintenance	• Operating Procedures
Major Emergency or Disaster	Emergency Shutdown Systems	Operations & Maintenance, Station Services	• Operating Procedures
	Transmission Control Center	Gas Control	• TD-4444P-02: Gas Transmission Control Center Emergency Response
	Business Continuity Plans	Gas Emergency Preparedness	• Business Continuity Plan
	Gas Emergency Response Plan (GERP)	Gas Emergency Preparedness	• EMER-3003M: Gas Emergency Response Plan
	Storage Well Crisis: Response Plan	Reservoir Engineering	• Well Control Tactical Considerations • UGS–E1, Standard - Design and Specifications for Casing, Tubing, and Wellhead Equipment • UGS-AD, Procedure, Rig Evacuation Procedure • UGS-AE, Procedure, Safety and Environmental Plan • UGS-AF, Procedure, Well Signage, Gas Storage Wells • UGS-AG, Procedure, Well Work • UGS-AL, Procedure, BOP Inspection • UGS-AM, Procedure, PGE Well Site Manager • UGS-AN, Standard, Well Control
	Storage Well Crisis: Water	Reservoir Engineering	• Well Control Tactical Considerations
Major Emergency or Disaster	Storage Well Crisis: Equipment	Reservoir Engineering	• Well Control Tactical Considerations

Underground Storage Risk and Integrity Management

Asset Type: Well			
Threat(s)	**Preventative and Mitigative Measure(s)**	**Department(s)**	**Reference Document(s)**
	Emergency Management Advancement Program (EMAP)	Reservoir Engineering	• Well Control Tactical Considerations
	Company Emergency Response Plan	Gas Emergency Preparedness	• EMER-3001M: Company Emergency Response Plan (CERP)
	GERP-Based Exercises	Gas Emergency Preparedness	• EMER-3003M: Gas Emergency Response Plan

Abnormal Operating Conditions

SUMMARY

Purpose: This procedure describes the identification and treatment of abnormal operating conditions (AOC).

Frequency: Continuous process.

Why: This procedure is established to support and meets the code requirements as set forth in the Compliance Requirement section of this standard.

When: Continuous process.

SAFETY

n/a

TARGET AUDIENCE

This procedure applies to all Gas Operations personnel whose work includes field maintenance and operations, and staff support or direction for maintenance, operations, engineering and risk assessment/risk management.

This includes storage asset family reservoir engineers, project managers and supervisors, and GPOM staff

TABLE OF CONTENTS

STEPS

1. Background - AOC Definition

GSAM adopts the definition provided by PHMSA of an abnormal operating condition (AOC):

> *A condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:*
>
> - *Indicate a condition exceeding design limits; or*
> - *Results in a hazard(s) to persons, property, or the environment.*
> - *Indicate a potential downhole problem not related to design or hazard(s) but that may risk the integrity of the well and/or reservoir (i.e. review of casing inspections or other well inspections).*

AOC also Includes events found in monitoring data sources (Sources) for threats that may impact the Storage assets preventative and mitigative standards and procedures to manage risk of the threats.

In addition, a condition that is abnormal or potentially a non-conformance may be considered as an AOC and documented as such, even though it is judged to present no hazard or to exceed no design limit.

Documenting these for trending and further assessment processes is to be performed in the CAP system, change control system or otherwise documented in a memo to GSAM engineering for further consideration.

GSAM can rely on its SMEs to determine whether an AOC has arisen in addition to the definition provided above.

2. Requirements / Steps

AOCs are addressed in a number of procedures in the GSAM guidance documents, and in the Gas Operations guidance documents employed by GPOM in the maintenance and operation of storage field related assets. Refer to TD-4800S, Continuing Surveillance.

2.1. Document AOCs

<u>GSAM</u>: Document AOCs and corresponding assessments either as set forth in Procedure 22 Management of Change in situations where an AOC requires a deviation, or in the project file for situations that are addressed by existing guidance documents.
<u>Note</u>: Documentation of AOCs helps inform the risk assessment of the assets and treatment of the risks (see Standard 1, Asset, Threat, and Risk Management)

2.2. Include AOCs in process safety assessments

Include assessments of applicable AOCs (and the recognition and treatment of AOCs) in

- process hazard assessments performed during planning and execution of well work.
- pre-startup safety reviews.
- other safety review/assessment elements of managing storage assets

2.3. Conduct Reviews of AOCs

<u>GSAM</u>: Conduct periodic reviews of documented abnormal operating conditions and Sources for the purpose of establishing trends or lessons learned and modifying existing procedures to prevent recurrence. Reviews shall be documented.

2.3.1. Conduct a review as a central element of the process hazard assessment that is conducted of the wells and well work.

2.3.2. Conduct periodic reviews as new information emerges through PG&E's operations or industry knowledge.

2.3.3. Conduct a review of well work AOCs including review of applicable well history when planning well work, for example, review past kill history (daily logs and history reports) on a particular well when planning kill work for that well, and when developing work plans (Well Site Manager (WSM) Procedure Section 3, Communication Requirements for the WSM include).

2.3.4. Include well work AOCs in the formal contractor critique meetings that constitute reviews of the season well work upon conclusion of the well work.

2.3.5. Conduct periodic reviews of reservoir operations AOCs, typically logged by GPOM as corrective notifications in SAP. This may be done in conjunction with Station Engineering.

2.4. Instruct Contractors

<u>GSAM or GPOM</u>: Instruct contractors that they must notify PG&E Gas Contractor Safety Program Manager (GCSPM – "safety rep") of all incidents or injuries immediately. Notification must occur to both the well site manager (WSM) and GCSPM and a follow up report must be

provided by the contractor and received by the WSM or GCSPM within 24 hours of the incident. (Refer to Procedure AG, C notification and documentation, Section 4.

3. Reference - Example AOCs

Process hazard assessments conducted of well work contain a variety of "what if" conditions that can constitute AOCs and can result in hazards and consequences. These serve as examples of AOCs. When developing a PHA for upcoming work, review similar previously conducted PHAs for similar work to consider AOCs.

AOCs do not necessarily present increased hazards. Some PHMSA publications and other Sources may characterize AOCs as a non-emergency conditions in which some design limit has been exceeded, or simply a variation from normal operations.

END of Procedure

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, GSAM

GOVERNING DOCUMENT

GSAM Standard 1 Section 9

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

TD-4800S, Continuing Surveillance

GSAM Procedure 22, Change Control

GSAM Procedure AC, Management of Change for Well Rework

GSAM Procedure, PG&E Well Site Manager Guidance Document Process

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 19 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 19 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Emergency Response / Emergency Preparedness

SUMMARY

This standard introduces the emergency preparedness / response plans to address accidental loss of containment, equipment failures, natural disasters, and third-party emergencies (CCR 1726.3(d)(15) and 1726.3.1).

Emergency response and preparedness are addressed in several areas within the set of GSAM-specific guidance documents, and in companion documents. Together these plans represent the integration of PG&E's gas pipeline and storage operations.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

Gas Pipeline Operations and Maintenance (GPOM)

Safety:

n/a

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EMERGENCY RESPONSE PLANS

1. Gas Emergency Response Plan (GERP) EMER-3003M

A plan to guidance to respond to an emergency and events should be prepared and maintained by the Gas Emergency Preparedness Department (GEP). The primary emergency operations guidance document applicable across all of Gas Operations includes:

- Utility Standard: EMER-6010S - Gas Emergency Response Plan Training, Exercise, and Evaluation

The Gas Emergency Response Plan (GERP) meets all requirements mandated by government regulatory entities, in order to minimize the hazard resulting from a gas pipeline emergency.

Gas Operations personnel with emergency response responsibilities receive both training on GERP content and participate in periodic exercises to develop and test personnel competency, and to confirm or identify needs for revisions to GERP content. Records of personnel training and testing, and records of these exercises are maintained by GEP in Gas Operations.

2. Well Control Tactical Considerations Plan (WCTCP)

This plan provides guidance to respond to a storage well emergency or event and shall be prepared by GSAM and GEP. It is published by GEP as an appendix within the GERP and is the GSAM well blowout contingency plan that includes site-specific surface intervention and relief well plans.

3. Emergency Response Table-Top Exercise Plan

This plan ensures that applicable staff receives training in the use of the emergency preparedness / response plans, and that personnel are familiar with emergency plans and procedures.

- GEP manages the overall exercise.
- The exercise is designed to test the effectiveness of the emergency preparedness / response plans (WCTCP and GERP).
- The emergency response exercise is scheduled and facilitated by GEP and consists of creation of emergency scenario, rehearsal by emergency response personnel of operations and activities to address the scenario, and critical review of emergency

response plan effectiveness and personnel familiarity and performance under the emergency response plan.

- GEP After Action Reviews (AAR) provide feedback on the following, and document in the exercise report:
  - The familiarity of emergency response personnel to the emergency response plans and the performance of emergency response personnel, to either confirm capabilities are as desired or to identify where capabilities need to be strengthened further, and develop and implement plans accordingly. Documentation of emergency response familiarity and capabilities is included in the post-exercise report.
  - The effectiveness of the emergency response guidance documents to either confirm document effectiveness is as desired or to identify where guidance documents need to be revised to achieve the desired level of effectiveness. Documentation of emergency response plan effectiveness is included in the post-exercise report issued by GEP. Emergency response plan improvements desired as a result of the exercise are managed through PG&E's Corrective Action Program.

4. Well Control and Blowout Prevention in California - Equipment Selection and Testing (CalGEM Procedure MO7)

GSAM shall prepare and maintain guidance documents to ensure well control is maintained at all times during well work operations (see GSAM Well Control Standard)

CalGEM’s Procedure MO7 (Procedure MO7) – Blowout Prevention in California -Equipment Selection and Testing, is a guide published by CalGEM for engineers and operators of wells in California as well as the CalGEM staff. The manual is designed to help operator personnel in planning their well operations and oriented primarily toward the equipment involved in blowout prevention.

By serving as a single-source guide to blowout prevention equipment (BOPE) used in oil, gas, and geothermal operations in California, the Procedure MO7 manual helps operators conform to the BOPE requirements of the California PRC and the CCR. (Refer to GSAM Standard 1 Section 3)

5. Rig Evacuation Procedure (GSAM Procedure AD)

GSAM shall prepare and maintain guidance documents for the evacuation during well work operations

GSAM Procedure AD, Rig Evacuation Procedure is developed and owned by GSAM and applies to personnel working on a drilling rig in PG&E's storage fields and provides guidance for the evacuation during well work operations.

6. Facility Evacuation Plan

GPOM should prepare and maintain facility evacuation plan for each of PG&E's three storage fields and address the evacuation of personnel from facilities on site and from the entire site.

7. Wildfire Response (TD-4911P-04, Storage Wildfire Response)

GSAM should prepare and maintain guidance documents provide guidance to emergency operations personnel in the management of gas storage well assets impacted by wildfires.

Utility procedure TD-4911P-04 is intended for use when the Operations Emergency Center (OEC) or the Gas Emergency Center (GEC) have been activated.

8. Pre-Fire Safety Plan

GPOM should prepare and maintain safety plans for the local fire department regarding how to approach a facility in the event of a fire. It should include access and egress information, flammable and hazardous materials on site, and PG&E contacts.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM

GPOM

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3

Emergency Response / Emergency Preparedness

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

n/a – references are set forth in the sections of the standard above.

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 20 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?

Converted RIMP Section 20 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Security

SUMMARY

Security at PG&E gas storage assets including limiting access to storage fields in general, and storage wells during drilling, workover, operation, and abandonment activities, is accomplished in accordance with the standards, plans, and guidelines presented in this standard. Collectively, these comprise the site security risk mitigation program.

This standard describes the documents in place that comprise or are related to the security plans for storage well assets.

TARGET AUDIENCE

Gas Pipeline Operations and Maintenance (GPOM)

Contract personnel who work at storage fields.

Gas Storage Asset Management (GSAM)

PG&E Corporate Security

Safety:

n/a

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Security

REQUIREMENTS

1. Guidance Documents

Collectively, the guidance documents comprise the site security risk mitigation program.

- Utility Standard: TD-4050S Security Standard for Gas Operations is the primary guidance document.
- PG&E TD-4800S, Continuing Surveillance
- North American Electric Reliability Corporation (NERC) tier 1 standard / penetration testing checklist and procedure may be used periodically by PG&E Corporate Security to inspect security measures at storage facilities.
- TSA Pipeline Security Guidelines, April 2018.
- General requirements for design and construction of fences and gates are in located in Numbered Document L-50, “Property Fence and Gates.
- Standard AF, Well Signage – Gas Storage Wells
  - Inspection for damaged or missing signage and mitigations if signage is out of order
- TD-4430P-02-F09, Gas Facility Security Checklist
- Site Security Plan – see GPOM or Corporate Safety
- SEC-2001S Physical Security Program Standard
- SEC-2002S Visitor Escort and Employee Access Controls Standard

Plans involving security issues are developed by Gas Operations in conjunction with PG&E’s Corporate Security Department. GPOM as the lead operating organization for the storage fields is responsible for implementation of the security plans with Corporate Security.

PG&E may employ additional measures to enhance site security based on an analysis of site-specific factors.

2. Site Inspections and Audits

Site inspections for review of safety and security assurance are performed by:

- GPOM to verify that requirements of this section are met and maintained.
  - TD-4430P-02-F09, Gas Facility Security Checklist

- Corporate Security, using any of the guidance documents listed above as guidance or auditing protocol.

3. Security during Well Work

Well work program documents and well procedure and safety kickoff presentations developed by GPOM, PG&E Gas Contractor Safety Program Management and GSAM address the process to limit access to storage wells during drilling, workover, operation, and abandonment activities and guidance for temporary and replacement of permanent signage to meet requirements in GSAM Standard AF, Well Signage - Gas Storage Wells.

These are supplemental to standard GPOM and Corporate Security Department security procedures applicable to each storage facility.

4. Flammable Material and Equipment

Sources of ignition and flammable-type equipment and materials shall be located in a manner to provide for the ongoing safety at the wellhead or well site. These guidance documents are adopted as addressing this requirement for well sites:

- TD-4640P-01 that addresses hot work
- TD-4551P-07 that addresses hazardous area classification
- TD-4430P-02 that covers general major gas transmission station maintenance and includes general requirements for locating flammable material at compressor stations.

5. Fences and Enclosures

When used at well locations, fences or enclosures shall comply with applicable fire codes and regulations.

6. Access Roads

Access roads shall be maintained by GPOM in a condition that permits personnel and equipment access to the wells.

- Storage facility roads on PG&E’s property by ownership or property leased by PG&E are maintained by GPOM.
- The condition of storage facility access roads owned by others, such a counties or reclamation boards, is monitored by GPOM. If conditions are judged by PG&E to be unsatisfactory, PG&E shall take the steps necessary to achieve satisfactory condition.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GPOM - as the lead operating organization for the storage fields is responsible for implementation of the security plans with Corporate Security.

GSAM - responsible for arranging for the security during well work. And for performing inspections of well signage if permanent signage has to be removed for well rework.

GOVERNING DOCUMENT

GSAM Standard 1

Utility Standard: TD-4050S Security Standard for Gas Operations

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3

Guidelines issued April 2011 by the Department of Homeland Security/Transportation Security Administration (TSA)

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

Procedures referenced in the requirements section above.

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 21 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 21 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Management of Change

SUMMARY

Purpose: This standard describes the requirements for change control.

SAFETY

n/a

TARGET AUDIENCE

This standard applies to all engineering and technical personnel engaged in well engineering, design and rework, primarily:

- Gas Storage Asset Management (GSAM)
- Gas Pipeline Operations and Maintenance (GPOM)

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Background

Change control is performed to manage change. For the purposes of the change control program, a change is an activity that results in a difference between the current state and a future state by addition, modification, or substitution of processes, equipment, facilities, personnel, or procedures.

Change control includes monitoring AOC's and data sources for threats that may impact the Storage assets preventative and mitigations, standards, and procedures to manage risk of the threats (See Table below).

Management of Change

Table 1 - Data Sources

Category	Data Source	Threat Review Triggers / Thresholds
Governmental Department / Agency Reports	(1) PHMSA - reportable incident database (2016 forward only available)	All PHMSA significant events (SIF or $50K in 1984 dollars)
Material Failure /	(1) PG&E lab analysis (material and vendor)	Any findings that may compromise the integrity of the Storage Facilities
PG&E Events	(1) PG&E SMEs – Field observations and incident tracking report (AOC)	All near misses and AOC incidents
Audit	(1) CalGEM annual review	All findings
Industry Associations	(4) Benchmarking with other storage operators	Process, procedures, and/or regulatory changes
Media / External Reports	(1) Industry events publicized in the media or though PG&E communications or through AGA, INGAA, PHMSA and CalGEM	All incidents applicable to Storage (These may be reported above)
Other / Asset Family Specific	(4) participation in state, federal, and PRCI research	All applicable research to storage facilities
Threats identified by other Asset Families	(1) RCC	All items applicable to Storage

Requirements

Change control guidance is provided in the documents listed in Table 1 to this standard .

Technical discussion and justification for a change that exceeds the threshold requiring the application of MOC procedures may also be documented in a published GSAM whitepaper. Published GSAM whitepapers are approved and housed using PG&E's Electronic Document Routing System (EDRS) and the GSAM shared drive.

GSAM Procedure AC, Management of Change for Well Rework provides guidance for managing changes required during well rework activity and categorizes the level of MOC required as Category 1, Category 2, or Category 3 based on the change type required. The qualifying activity is provided in GSAM Procedure AC, Management of Change for Well Rework.

As describe in more detail in GSAM Procedure AC, Gas Operations utility procedure form TD-4014P-01-F01 is used to document changes for Category 2 and Category 3 MOC levels. Documentation for Category 1 changes is accomplished on the daily report.

Audits

Audits shall be conducted periodically by GSAM of the MOC process.

Table 2 – Change Control Guidance Documents

The five guidance documents presented first in this table contain the requirements for MOC applicable to all of Gas Operations including GSAM.

Document / Form	Description / Application
Gas Operations guidance document: Utility **Standard**: TD-4014S - Change Control (Management of Change)	Standard describes the structure and requirements of the PG&E system for Gas Operations change control (Management of Change) to mitigate safety, health, and environmental risks.
Gas Operations guidance document: Utility **Procedure** TD-4001-P01 - Procedural Change	Procedure for applying MoC to procedure changes
Gas Operations guidance document: Utility Procedure - Field Change Control Process (TD-4014S-F01)	Provides guidance for change control across Gas Operations. This is used for GSAM process and guidance changes other than those set forth further below, and is intended for "…changes such as facility design, facility operation/maintenance, assets, guidance documents, organizational structure, suppliers/contractors, and tools and equipment." The Gas Operations Process Safety Department is the content owner.
MoC Log	This is an index of MoCs created in GSAM that resides in the GSAM MoC folder on the shared drive. It is also the source for GSAM MoC numbers that are part of the catalog systems for MoCs.
Station Management of Change Form TD-4014P-03-F01	Guidance document for MoC for GPOM station operations at McDonald Island and Los Medanos. Maintained on GPOM Sharepoint
GSAM Procedure AC – Management of Change for Well Rework	Guidance document for well reworks

END of Procedure

Management of Change

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lucy Redmond, Director, GSAM

GOVERNING DOCUMENT

GSAM Standard 1

GSAM Standard 22 – Management of Change

Gas Operations guidance documents listed in Table 1 above.

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

See Appendix A which lists change control guidance documents

Standard TD-4014S Gas Operations Management of Change (MOC)

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces IMP Section 22 and Appendix AC, of the Underground Storage Risk and Integrity Management Plan, Rev 5

Management of Change

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 22 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Communications

SUMMARY

This standard contains the requirements for internal and external communications regarding storage asset construction, operation and maintenance.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM) – external regarding reservoir and wells with CalGEM and PHMSA).

Internal regarding reservoir M&O
- Gas Pipeline Operations and Maintenance (GPOM)
- Corrosion Department (CD)
- Facilities Integrity Management Program (FIMP – Compression and Processing asset family)
- Gas System Operations (GSO)

SAFETY

n/a

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Communications

REQUIREMENTS

1. Internal Communications

GSAM personnel are responsible for preparing and communicating guidelines for maintaining reservoir and well functional integrity, including but not limited to the following:

1.1. GSAM develops and maintains guidance documents specific to storage well and reservoir assets and develops or confirms storage-specific content for guidance documents that are developed by the Gas Operations Guidance Documents and Engineering Services Department or elsewhere in Gas Operations. An index of guidance documents applicable to storage operations is provided in Standard 1, Appendix 3, Guidance Document Reference.

1.2. GSAM provides access to guidance documents as set forth in the target audience specified above.

1.3. GSAM takes the initiative to communicate storage-specific guidance document content to storage engineering and operations personnel, contract personnel and personnel elsewhere in Gas Operations (e.g., GPOM, Gas System Operations). These activities are documented as remarks and attendance lists in well work project kickoff meeting reports, correspondence transmitting revised guidance documents to the target audience, five-minute meeting guidance that is provided to the target audience, reports on assessments of storage design, maintenance and operations, written recommendations or direction, etc. Documentation is maintained in the project or facility files in the GSAM shared drive.

1.4. GSAM provides technical peer review of the results of Gas Operations personnel operating, inspection, data gathering and data reporting activities regarding gas storage assets, to not only use the information in managing storage operations, but also to ensure that Gas Operations personnel understand and can perform as required as set forth in the guidance documents affecting storage assets. These activities are documented as correspondence requesting additional or revise data, and correspondence and reports that assess practices or circumstances and may contain recommendations or direction. Correspondence and reports are filed in the GSAM shared drive folder for that asset.

Communications

Table 1: Schedule of Internal Notifications and Reports

Deliverable	Schedule	Recipient
AG Procedure - Well Work – Well site manager must provide an IMMEDIATE report on all injuries, incidents, near-miss events, hazardous material and hazardous waste spills	immediate	PG&E on-site Representative
AG Procedure - Well Work – Contractors must notify of all incidents or injuries	immediate	PG&E representative
10 Standard - Pressure Tests and Annulus Monitoring – Report any anomalous annulus pressures	Immediate	GSAM
S15 Procedure - Casing Inspection Logging and Data Assessments - report anomalies or features or trending that requires further investigation or remediation of the well to address a potential high risk of imminent loss of containment	Immediate	GSAM director, manager, supervisor and engineer
19 Procedure - Abnormal Operating Conditions - report all incidents or injuries	Immediate	PG&E Gas Contractor Safety Program Manager (GCSPM – "safety rep")
AH Procedure - Well Work Contractor Competency - Contractors must report all incidents or injuries	Immediate	PG&E representative
I5 Procedure - Uphole Safety Valve (UHSV) Leak-by Test Procedures - report any abnormal issues to the Operations supervisor	Immediate	Operations supervisor
AE Standard - Safety and Environmental Plan - Well Entry Work - Report any unsafe situations	Immediate	contractor supervisor and PG&E representative
AE Standard - Safety and Environmental Plan - Well Entry Work - Report any endangered species thought to be present	Immediate	PG&E representative
AE Standard - Safety and Environmental Plan - Well Entry Work - Report any spills	Immediate	PG&E representative

Communications

2. External Communications

Table 1 below summarizes the schedule of deliverables to be submitted regarding risk assessment results and operations.

Table 1: Schedule of External Notifications and Reports

Deliverable	Schedule	Agency
48 hour advance notifications		
Standard 9 - to witness tests	48 hrs in advance of running	CalGEM
Standard 10 –running a log survey	48 hrs in advance of running	CalGEM
Procedure R14 – DHSV testing	48 hrs in advance of running	CalGEM
Procedure T16 – prior to running noise/ temperature survey logs	48 hrs in advance of running	CalGEM
Procedure T16 – noise/temperature survey logs	48 hrs in advance of running	CalGEM
Other advance notifications		
Standard 10 – advance approval of use of liquid additives other than brine, corrosion inhibitive or biocides	In advance	CalGEM
PERIODIC REPORTING		
Annual		
Annual Production Report	Annually by March 15	CalGEM
Standard 1 - Asset Management Plan	Annually by September 30	CalGEM
Annual PHMSA report	Annually by March 15	PHMSA
Inventory Verification Report (by field)	Annually by November 30	CalGEM
Quarterly		
Water Production Report	Quarterly	CalGEM
Monthly		
Gas Injection and Production Reports	Monthly	CalGEM
Immediate		
Standard 10 - Any anomalous annulus pressures	Immediate to CalGEM and internal to GSAM	CalGEM
Identified anomalies or features.	Immediately	CalGEM

Communications

Deliverable	Schedule	Agency
Within 30 Days		
Standard 9 – well logs	w/in 30 days of being run	CalGEM
Procedure S15 – casing inspection logging	w/in 30 days of being run	CalGEM
Procedure T16 – noise/temperature survey log evaluation results	w/in 30 days of being run	CalGEM
Procedure U17 – gamma ray neutron logging	w/in 30 days of being run	CalGEM
Procedure V18 – cement bond logs	w/in 30 days of being run	CalGEM
Other notifications and reports		
Standard 10 – unsuccessful pressure test	No schedule	CalGEM
Standard 10 – CalGEM approval to use well after unsuccessful pressure test	In advance or using the well	CalGEM
F2 - Wellbore Schematic and Info Sheets Records	No schedule	CalGEM
G3 - Proposed wellhead diagram (in the NOI) and the as-built well bore diagram	No schedule	CalGEM
CalGEM OG 100 / well history	w/in 60 days	CalGEM
AG – Well Work Program (Notice of Intent Submittal)	Prior to conducting work	CalGEM
Incident Report – F7100.2 & Supplemental Incident Report	As needed, as soon as practicable, not to exceed 30 days after detection	PHMSA
Construction notification of new underground natural gas storage facility or the abandonment, drilling, or well workover (including replacement of wellhead, tubing, or a new casing) of an injection withdrawal, monitoring, or observation well for an underground natural gas storage facility.	As needed, 60 days prior	PHMSA
Acquisition or divestiture of an existing underground natural gas storage facility	As needed, no later than 60 days after	PHMSA
Prepared for purpose of responding to external data requests		
Yearly Storage Well Evaluation Report	Annually by January 31	Internal Reporting
Well Risk Evaluation and Construction Standard Implementation Plan.	Annually by January 31	Internal Reporting

Communications

Deliverable	Schedule	Agency
Annual report on Well Need and Usefulness	Annually by January 31	Internal Reporting

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

Communications

DOCUMENT RECISION

This replaces Section 23 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 23 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Quarterly and Monthly Reporting to CalGEM

SUMMARY

PURPOSE

Reporting of production information on a monthly and quarterly basis to CalGEM.

WHAT

This procedure addresses the monthly CCR (1937.1) and quarterly PRC 3227 (Notice to Operators December 8, 2014) reporting of gas and fluids production information to CalGEM..

WHEN

On-going.

SAFETY

n/a

TARGET AUDIENCE

Reservoir Engineering (RE), Gas Storage Asset Management Department (GSAM)

TABLE OF CONTENTS

STEPS

1. Reservoir Engineering Steps

Review the previous reports for correction or revision as necessary.

1.1. Prepare the form required by CalGEM for reporting to be submit on GSAM database.

1.2. Collect the required information.

1.3. Complete the form with required information

1.4. Save completed form on GSAM database and notify supervisor of completion

1.5. Ensure that reports are reviewed and approved.

1.6. Submit information to CalGEM .

END of Procedure

DEFINITIONS

Refer to definitions in API 1171 and CalGEM's regulations.

IMPLEMENTATION RESPONSIBILITIES

Reservoir Engineering, GSAM

GOVERNING DOCUMENT

GSAM Standard 1

GSAM Standard 23 - Communication

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

New Document.

Supplemental References:

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

New Document

Quarterly and Monthly Reporting to CalGEM

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?

Internal Auditing

SUMMARY

This standard describes the auditing processes that are used to confirm that PG&E storage operations are complying with requirements across all procedures, practices and other guidance documents, and to identify opportunities to make improvements to correct activities if either needed or beneficial.

Audits and reviews are also required to be made of the work being done by storage personnel to determine the adequacy and effectiveness of the procedures used in operation and maintenance of storage wells and facilities. These audits support the continuous improvement of guidance documents.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

Gas Pipeline Operations and Maintenance (GPOM)

Corrosion Department (CD)

Safety:

n/a

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REQUIREMENTS

1. Overview

Internal auditing is viewed as accomplished in two parallel methods

1. Auditing may be conducted periodically of the performance of GSAM and other PG&E organizations relative to the requirements of this and other guidance documents applicable to gas storage assets, engineering, maintenance and operations.

2. Auditing is conducted as a normal course of daily activities by SMEs, through formal and informal inspections and assessments described throughout this IMP.

3. Testing and training of employees and contract personnel is also considered a form of auditing – it confirms personnel competency and leads to competency improvements as appropriate.

These processes are used to confirm that PG&E is complying with requirements across all procedures, practices and other guidance documents, and to identify opportunities to make improvements to correct activities if either needed or beneficial.

Audits are also required to be made of the work being done by storage personnel to determine the adequacy and effectiveness of the procedures used in normal operation and maintenance of storage facilities. These audits support the continuous improvement of guidance documents (ref Section 5).

2. Frequency

The frequency for internal audit is determined in accordance with risk assessment practices addressed throughout this IMP. For example, highest-risk activities for which a solid understanding is not held for guidance document or human performance effectiveness deserve the highest priority for internal audits, and may be the subject of continuous review during the normal course of maintenance and operations activities.

3. Process

Audits may be initiated by any PG&E organization but shall always involve GSAM leadership and staff. Audits may be conducted by PG&E or qualified third-party experts.

4. Audit Results Documentation

Audit results and findings shall be documented in a post-audit report, and reports shall be filed in the GSAM shared drive. Simple actions undertaken and completed promptly to correct aspects of storage asset management may be documented simply in revisions to the audit report. Actions that may require more substantial effort or that make take time to resolve shall be documented in and managed through PG&E's Corrective Action Program.

Audit findings that require PG&E to self-report to regulatory agencies shall be handled through PG&E's self-reporting process, administered by the Gas Operations Compliance Department.

5. GSAM Engineering

GSAM Engineering performs the following as part of routine work:

- Constant auditing of storage operations through procedures set forth throughout this IMP.
- Informal site inspections/auditing at storage fields.
- Oversight auditing of GSAM personnel.
- Auditing/review of storage reservoir and equipment operations including defects or issues identified by GSAM personnel or GPOM.
- Periodic auditing review of emergency response plans
  - GERP annual review/update cycle
  - Storage field-specific emergency response plans

GSAM Engineering also performs periodic audits of the MOC process.

6. QA Department

Gas Operations QA department audits work done by GPOM under various sections in this IMP as part of the routine QA processes within Gas Operations. GSAM may provide guidance to QA to help clarify what needs to be audited.

7. Corporate Security

CS auditing activities consist of

- periodic reviews of physical security
- Prepares and periodically updates security vulnerability assessments (requirement in site-specific security plans)

- Ensures facility is compliant with protection of sensitive information (requirement in site-specific security plans).
- Ensures facility is compliant with the latest security guidelines, directives and policies (requirement in site-specific security plans).

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM Personnel

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

n/a

APPENDICES

n/a

Internal Auditing

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 26 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 26 to this standalone standard	Minor language changes were made for clarity. No content changes were made

Creating and Updating Storage Wellbore Schematics

SUMMARY

This procedure addresses the requirements in CCR 1726.4.1 regarding wellbore schematics.

Purpose: Provide standards and procedures for creating and updating storage wellbore schematics. (CCR 1726.4(a)(5)(F). Data specified in the form of either graphical diagrams or flat file data sets meets the requirement.

What: The wellbore schematic or file data set provides a graphical representation of the wellbore, downhole equipment and tubulars, dimensions and installed depths, and anomalies detected from Vertilog, GR/N and T/N in each storage well for active wells only. Note: the official document of record of the data reflected on the wellbore schematic is well asset database.

Why: The document is to ensure that the wellbore schematics are updated to reflect the current physical configuration of the storage wells.

When: Create wellhead diagram and update for any changes of wellbore, downhole equipment and tubular after rework operation, and anomalies detected from casing integrity surveys (Vertilog, GR/N and T/N).

TARGET AUDIENCE

Storage asset family reservoir engineers, project managers and supervisors, and GPOM staff

- Reservoir Engineering (RE) creates wellbore schematics or file data sets for active and all other wells included in a storage field's area of review (CCR 1726.4.2).
- RE reviews wellbore schematics for completeness and quality.
- RE updates wellbore schematics.

Creating and Updating Storage Wellbore Schematics

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SUBSECTION TITLE PAGE

STEPS

1. Document existing wellbore configurations

GSAM Reservoir Engineering: Create and document existing wellbore configurations including, at a minimum, the following:

1.1. PG&E named as well owner

1.2. Lease name

1.3. Well location: section, township and range, and GPS coordinates

1.4. Well name/number

1.5. API number (12-digit)

1.6. Spud date

1.7. Ground elevation from sea level, KB measurement or reference elevation

1.8. Base of groundwater with <3,000 ppm of dissolved solids content (shown as base of fresh water (BFW)

1.9. Base of groundwater with <10,000 ppm of dissolved solids content (shown as United States Drinking Water (USDW)

1.10. Hole size diameter and depth of drilled hole

1.11. Completion date

1.12. Date of last rework

1.13. Sizes, weights, grades for:

1.13.1. Conductor dimension and depth

1.13.2. Surface casing dimension and depth

1.14. Sizes, weights, grades, and connection types for

1.14.1. Production and inner string casing dimension and depth

1.14.2. Tubing dimension and depth

1.15. Cement fill behind casings including

1.15.1. Top and bottom of cemented interval

1.15.2. Method of determination (i.e. cement bond log & year run)

1.16. All information used to calculation the cement slurry (e.g., volume, density, yield), including cement type and additives

1.17. Equipment details where installed:

1.17.1. Subsurface safety valves: Make/model, dimension and depth

1.17.2. Casing patch dimension and depth

1.17.3. Packer element: Make/model and depth

1.18. Production liner hanger, liner dimension and depth

1.19. Stage collar depth

1.20. Depth of casing shoes, stubs, or liner tops

1.21. Known anomaly and feature depths that influence flow in the well or may compromise mechanical integrity of the well

1.22. Depth of perforated intervals, water shutoff perforations, cement port, cavity shot, cut, patch, and casing damage

1.23. Top of junk or fish left in well

1.24. Cement plug detail

1.24.1. Date emplaced

Creating and Updating Storage Wellbore Schematics

1.24.2. Top and bottom depths

1.24.3. Method of determination

1.24.4. Type and density of any fluid between plugs

1.25. Depths and names of formation(s), zone(s), and geologic markers penetrated by well, including the top and bottom of the gas storage zone(s) and top and bottom of the confining strata

1.26. Footnote all measurements reference to KB

1.27. All items noted above for previously drilled or sidetracked wellbores (CCR 1726.4.1(6))

1.28. PG&E defined wellhead type. Note: Wellhead and wellhead valve assembly equipment by model and pressure rating are summarized on a general wellhead sheet by wellhead type.

2. Update Wellbore Schematics

RE: Update wellbore schematics for any changes of downhole equipment and tubular after well rework operation and anomalies and features detected from casing integrity surveys

Verify log and other feature depths match wellbore schematic or other logs.

3. Update Directional Surveys

RE: Update and maintain directional surveys that provide inclination, azimuth measurements, bottom hole location, and surface location (CCR 1726.4.1(3))

4. Review Wellbore Schematics for Completeness and Quality

GSAM IM: Review all information developed following this procedure for completeness and quality. Quality reviews shall be performed to 1) review logs and other data for missing scales and well information, 2) verify that log and feature depths match wellbore schematics or other logs, and 3) make depth corrections to wellbore schematics based on review and verification.

5. Wellbore Schematic and Info Sheets Records

RE: Submit to gas storage database G:\RSRVRENG\GSAM Wellbore Schematic and Info Sheets and provide an electronic submission to CalGEMs (CCR 1726.3.1(4-5))

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, Gas Storage Asset Management Department

Creating and Updating Storage Wellbore Schematics

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix F2 in Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Larry Kennedy, Strategic Planning Chief, GSAM

Revision Notes

Where?	What Changed?

Converted RIMP Appendix F2 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Creating and Updating Storage Wellhead Diagrams

SUMMARY

Purpose: Provide standards and procedures for creating and updating storage wellhead diagrams.

What: The wellhead schematic provides a graphical representation of wellhead components including dimensions and pressure rating using API Standards. Note: the official document of record of the data reflected on the wellhead schematic is the well asset database.

Why: The document is to ensure that the wellhead component dimensions and pressure rating reflect the current physical configuration of the storage wellhead.

When: Create wellhead diagram and update for any changes of components, as needed, or after rework operation.

TARGET AUDIENCE

Storage asset family reservoir engineers, project managers and supervisors, and GPOM staff. Specific responsibilities lie with the following:

- Wellhead vendor
- RE
- Design Drafting

TABLE OF CONTENTS

Creating and Updating Storage Wellhead Diagrams

STEPS

1. Verify/update wellhead diagram.

Wellhead vendor creates wellhead diagram in digital format for active wells only.

GSAM Project Management (PM): Document/verify component dimensions and pressure rating of wellhead diagram, or mark up an existing wellhead diagram as needed, including

1.1. Type or make of wellhead and pressure rating

1.2. Casing head

1.3. Casing double studded flange

1.4. Tubing head

1.5. Tubing hanger

1.6. Seals

1.7. Test ports

1.8. Hydraulic control line ports

1.9. Surface casing valve

1.10. Casing wing valves

1.11. Tubing wing valves

1.12. Master Gate

1.13. Cross

1.14. Bonet

1.15. Temp rating of well head

1.16. Trim package

1.17. Date of installation and testing performed

2. Diagram Revision (Pre and Post Construction)

Post Construction: GSAM PM: Provide the above to Design Drafting who files in accordance with Gas Operations transmission as-built processes. Well schematic is contained in these diagrams and includes the BOM. Valve numbering appears on the P&IDs.

Before Construction: GSAM PM: Proposed wellhead diagram and the as-built well bore diagram submitted to CalGEM **as part of NOI and permitting.**

3. **Diagram Q/C (Post Construction)**

   GSAM Integrity Management (IM): Review for completeness and returned to GSAM PM if incomplete.

4. **Diagram Filing (Post Construction)**

   GSAM IM: Submit to Gas Storage Database and CalGEM

   .

END of Requirements

DEFINITIONS

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

Creating and Updating Storage Wellhead Diagrams

DOCUMENT RECISION

The replaces Appendix G in Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Larry Kennedy, Strategic Planning Chief, GSAM

Revision Notes

Where?	What Changed?
Converted RIMP Appendix G3 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Reservoir Integrity

SUMMARY

This standard addresses underground gas storage project data, testing and monitoring, and is supported in detail in the procedures listed in the Reference Documents section at the end of the standard.

Ongoing verification and demonstration of the integrity of the reservoir includes defining the underground gas storage projects reservoir and design basis (CCR 1726.4), demonstration that reservoir integrity will not be adversely impacted by operating conditions. Reservoir integrity is verified by inventory-bottomhole pressure surveys/shut-in test or other pressure decline analysis methods (CCR 1726.7(b)(2)(A), monitoring observation wells (CCR 1726.7(b)(2)(B), monitoring third-party existing and new wells (CCR 1726.7(b)(2)(C), performing measurement correlation/audits, and lost and unaccounted-for gas studies.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

- Integrity management engineers
- Well work project managers
- Technical work supervisors

Safety:

n/a

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Reservoir Integrity

REQUIREMENTS

1. Reservoir Characterization (CCR 1726.4(a)-(g))

Geological and engineering characteristics of the reservoir influence its performance and integrity capability. As new information that could influence integrity is available, the reservoir characterization is reviewed and updated.

The reservoir characterization addresses zones that may require isolation (for example USDW waters),rock characteristics such as lithology and lithologic variation, porosity, permeability, average thickness, areal extent, caprock thickness, caprock threshold pressure, reservoir/caprock fracture gradient, locations and characteristics of faults and fractures, location and characteristics of any offset hydrocarbon operations, reservoir temperature, original and conversion pressure, original and produced native oil, gas and water, original and current fluid properties such as density, viscosity and chemistry.

The characterization is illustrated in the form of structure maps, isopachous maps, and a geologic cross section drawn through at least one well location with a type log incorporating the deepest producing zone. Illustrations are clearly labeled as to scale and purpose, with clearly identified wells, boundaries, zones, contacts and other relevant data.

Reporting: Updated characterizations are made available to appropriate regulatory agencies (CCR 1726.4(b) thru (g)).

This information is maintained in current reports on GSAM Shared

2. Reservoir Design Basis (CCR 1726.4(a)-(d))

The reservoir design basis states the purpose of the storage service and incorporates operating limits that are updated to keep current. The design basis addresses the injection and withdrawal plans and methods, well type and distribution, maximum design reservoir and well flow rates, minimum design operating pressure and evidence for not exceeding geo-mechanical strength, maximum design operating pressure and evidence for not exceeding geo-mechanical or surface facility strength, observation well purposes and locations, cathodic protection systems, water source wells if any, water disposal operation, and surface and subsurface safety systems employed. The design limits guide the design of the wells and related equipment (See Standard E – Design and Specifications for Construction of Natural Gas Storage Wells). The design basis is illustrated in maps showing all well locations and key pipeline facilities, cathodic protection facilities if any, water source and disposal wells if any.

Reporting: An updated design basis is made available to appropriate regulatory agencies, particularly as it accompanies intended changes or well additions requiring prior regulatory approval (CCR 1726.4(b) thru (g)). Further, reports summarizing the design on GSAM Drive.

3. Inventory BHP Surveys/Shut-in Test or Other Pressure Decline Analysis Methods (CCR 1726.7(b)(2)(A)

Storage field inventory studies performed by GSAM verify the volume of gas in the storage reservoirs compared to the company booked volumes. Gas volumes that need reconciliation consist of native base gas, injected base gas, injected and withdrawn working gas (less fuel) and other losses, both measured and estimated. These studies consist of conducting a pressure-inventory analysis for each storage reservoir.

A detailed description of the methodology, terms, and definitions related to inventory studies is included in GSAM Procedure P12, Inventory Verification (pressure Hysteresis and Semi-annual Field Shut In testing).

4. Observation (OBS) Well Monitoring (CCR 1726.7(b)(2)(B)

Observation (OBS) wells are utilized to monitor gas pressure movement within a storage zone or other permeable zones above the storage reservoir and to monitor the potential for gas migration away from the storage zone or movement to other porous zones above or below the storage zone. Some OBS wells were originally oil/gas production wells obtained with the acquisition of the field and others were drilled as part of the development of the field.

Observation well pressure data is utilized to monitor the reservoir pressure versus inventory relationship and trends indicating field stabilization or anomalies which may be indicative of gas loss or migration.

Gas samples are obtained and analyzed from OBS wells and selected injection/withdrawal wells to determine if changes in gas composition occur over time and is conducted per Procedure O11, Gas Sampling Observation and Storage Wells. The samples may be taken from OBS wells completed in the fringe area of the storage zone and/or OBS wells completed in porous zones above or below the storage zone. This information is recorded in the Gas Storage Database (GSDB).

Changes in gas composition may indicate movement of storage gas toward storage boundaries, or may indicate a need to reassess the inventory (see GSAM Procedure P12, Inventory Verification (Pressure Hysteresis and Semi-annual Field Shut In Testing)) since gas composition can affect inventory calculation. This information is valuable for identification of potential storage gas migration.

Some injection/withdrawal (I/W) wells that are connected to the transmission pipe of the corresponding storage fields are not utilized to flow gas into or out of the reservoirs but are utilized for reservoir monitoring purposes similar to OBS wells.

5. Monitor Third-Party Existing and New Wells (CCR 1726.7(b)(2)(C)

Refer to GSAM Procedures Q13, Third Party Activities.

An important part of maintaining storage field integrity is verifying that any third-party wells within the protection acreage and/or penetrating the storage reservoir are adequately designed to prevent the leakage of gas from the reservoir, as well as evaluating the mechanical integrity of the third party wells. PG&E also attempts to periodically monitor third party wells to detect leaks that may develop later in the life of a well.

Survey and monitor third party drilling activities inside and outside of gas storage asset properties on a quarterly basis or more frequent if an increase of activity is identified.

PG&E seeks to obtain written access agreements with the operators of existing and new third-party active wells to minimize operational misunderstandings and future problems. This includes requesting well integrity evaluation data from third party well owner/operators following the frequency established using conclusions from PG&E's risk assessment and seeks assurances that all planned third-party wells that will penetrate its storage reservoirs comply with state regulations; PG&E does not waive any state regulation nor accept attempts to lessen any. If allowed by the operator, PG&E monitors the drilling, cementing and logging of any third-party well.

Results of PG&E's attempts to understand risks associated with third-party wells, risk assessments and operator contacts are documented in folders for the applicable storage field asset on GSAM's shared drive.

6. Measurement Correlation and Lost and Unaccounted For (LUAF) Studies

Metering errors and fuel/station gas usage for underground gas storage operations represent gas "losses" from inventory and are accounted for monthly. A variety of potential gas losses are considered when conducting analysis to verify gas inventory. Refer to GSAM Procedure P12, Inventory Verification (Pressure Hysteresis and Semi-annual Field Shut In Testing), Section 8.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM integrity management engineers

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Section 3 of GSAM Standard 1 addresses these requirements, and by reference applies these requirements to all guidance documents in the integrity management plan library of guidance documents.

REFERENCE DOCUMENTS

Developmental References:

Past editions of the GSAM Integrity Management Plan, and the standards set forth in Section 3 of GSAM Standard 1.

Supplemental References: Procedures referenced in the requirements section above.

GSAM Procedure O11, Gas Sampling Observation and Storage Wells

GSAM Procedure P12, Inventory Verification (Pressure Hysteresis and Semi-annual Field Shut In Testing)

GSAM Procedure Q13, Third Party Activities

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 8 of the Underground Storage Risk and Integrity Management Plan, Rev 5.

Reservoir Integrity

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 8 to this standalone standard	Minor language changes were made for clarity. No content changes were made

Inventory Verification (Pressure Hysteresis and Semi-annual Field Shut In Testing)

SUMMARY

This procedure provides guidance for field shut in testing for storage gas inventory verification. This is a process to meet Company accounting and financial reporting requirements. This is accomplished with weekly updates and final reports in November of each year.

TARGET AUDIENCE

Reservoir Engineering (RE)

- obtains weekly pressure reads
- obtains extended shut in pressure reads
- reviews pressure data
- evaluates storage gas inventory and pressure relationship
- communicates results

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Inventory Verification (Pressure Hysteresis and Semi-annual Field Shut In Testing)

REQUIREMENTS

1 Inventory Verification – Pressure Hysteresis (Weekly Monitoring)

1.1 RE obtains weekly wellhead pressure on every available storage wells tubing, casing, and other wellhead annulars (i.e., surface casing, inner strings).

1.2 RE reviews pressure data for reasonableness and anomalies

1.3 RE calculates weekly average reservoir pressure for each storage field

1.4 RE plots hysteresis curves for each storage field to monitor behavior relative to history

1.5 RE reports weekly results

1.6 RE, if need be, investigates and troubleshoots anomalies of the hysteresis behavior

1.7 RE communicates findings

2 Inventory Verification

RE performs the following calculations and evaluations to complete the Inventory Verification Study in Section 3-9 of this procedure

NOTE: Individual wellhead pressures are recorded during the field shut-in tests but prior to interference from hysteresis effects or changing reservoir pore volumes.

RE obtains extended shut in wellhead pressure on every available storage well at low inventory after the winter withdrawal and at high inventory after the summer injection

3 RE performs the Production Pressure-Decline Analysis

3.1 Review well pressures for evidence of leaks and/or the presence of fluid in the wellbore.

3.2 RE contours the pressure data to help identify if any low pressures are observed.

3.3 Convert surface pressures to absolute by adding the barometric pressure

3.4 Surface pressures are converted to BHP by adding the weight of the gas column determined by direct BHP measurements and/or by calculation.

3.5 Evaluate The average field pressures to establish a field stabilization trend or by using the actual pressure decline if timing of the shut-test precludes elimination of reservoir effect phenomena The factor z is computed using the properties of the stored gas from analyses of field and/or well samples.

NOTE: Gas Samples collected for monthly monitoring can be utilized for calculation of factor z. Refer to Procedure O11, Gas Sampling Observation and Storage Wells

3.6 BHP/z pressure values are calculated for each well and an average BHP/z is determined or a single BHP/z is calculated from a field average wellhead pressure.

3.7 The average field pressures are evaluated through the semi-annual shut-in test to establish a field stabilization trend or by using the actual production pressure decline if timing of the shut-test precludes elimination of reservoir effect phenomena.

3.8 The average BHP/z is then plotted versus the company book volumes.

4 RE calculates Non-Effective Gas:

4.1 Plot The final spring and fall BHP/z pressure values from Step 3.5 versus the total field inventory for those days. Draw A straight line through the points and extrapolated to zero psi.

4.2 Determine the Non-Effective Gas volume at zero psi rather than the BHP at abandonment

4.3 Plot Pressure decline lines for the six most recent consecutive years of operation and evaluate pressure decline lines in terms of continuing or revising the operating mode to improve field performance.

5 RE calculates the Gas-Per-Pound (Apparent Pore Volume):

Reservoir gas-per-pound (GPPr) or Apparent Pore volume (PV) is the slope of the line connecting an individual BHP/z calculated in Step 3.5 versus total field content and zero psi versus zero total field content. This is done for both the spring and fall shut-in test points and/or two other points determined by the intersection of the pressure decline trend (BHP/z) and two constant BHP/z's (generally one at maximum working inventory and one at low inventory)

5.1 For each semi-annual shut-in point calculated in Step 3.5, calculate total content divided by BHP/z and/or use points determined by pressure decline trend and the intersection of two constant BHP/z points.

5.2 Graphically connect all calculated points.

6 RE calculates the Cyclic Gas-Per-Pound (Effective Pore Volume)

Cyclic Gas-Per-Pound (GPPc) is calculated using the following steps. .

6.1 After each semi-annual shut-in test in calculated in Step 3.5, calculate previous total field content less the current total field content divided by the previous BHP/Z less the current BHP/z and/or use the pressure decline trend and the corresponding inventories consistent with the two constant BHP/z points.

6.2 Use All calculations that are performed using a spring shut-in as the current shut-in generate one set of data (the slope of all fall – spring cycle lines).

6.3 Use Calculations performed using the fall shut-in as the current shut-in. Generate a second set of data (the slope of all spring-fall cycle lines) and/or in the case of the pressure decline trend use the two other points determined by the intersection of the pressure decline trend (BHP/z) and the two constant BHP/z points (one high and one low).

6.4 Graphically connect calculated points of the same cycle, for example, all of the calculated slopes for the fall – spring cycle are connected and/or two consecutive BHP/z points.

7 RE calculates Pore Volume Ratio

Pore Volume Ratio is calculated using the following steps

a. Calculate the original BHP/z times the current total content divided by the original total content times the current BHP/z calculated in Step 3.5 for each semiannual shut-in and/or the two points generated by the pressure decline trend and the constant BHP/z point

b. Graphically connect all calculated points

8 RE calculates Inventory Variance

Operations from cycle to cycle can impact the storage reservoir pressure response data that is gathered during the semi-annual shut-in test. Thus, it is the trend over several cycles that could indicate what may be occurring in the storage reservoir.

Inventory Variance is the difference between book (or metered) total inventory and total content calculated using the following steps.

Inventory Variance is calculated using the following steps:

8.1 Calculate the total content using the original discovery line and the current BHP/z.

8.2 Subtract the calculated total content from the current metered total content.

8.3 Graphically connect all calculated points; spring points as one data set and fall points as a second data set.

9 Reporting

9.1 RE to verify results and written report annually with Subject Matter Experts and director

9.2 Communicate the results to GSO, WM&BD, and GSO Planning to provide well performance updates in a timely manner.

9.3 Develop and add a written report to the Gas Storage database and the director to submit report for the Sarbanes-Oxley compliance requirements.

10 Loss and Un-Accounted For Gas

Consider including the following gas losses when performing the assessments in this procedure.

- Engine starting gas utilized (number of starts times the volume of a typical start).
- Venting volume of compressor and piping each time a unit is shut down and the number of times it is shut down each month.

- Emergency shut down (ESD) blow down volumes.
- Other equipment depressurizing (volume of each event).
- Station fuel.
- Well blow downs (number of wells, starting pressure, and volume of each).
- Transmission pipe system header blow downs.
- Relief valve discharge occurrences and estimate of volume.
- Flash gas from atmospheric tanks.
- Flare gas, where applicable.
- Diffuse gas losses from leaking valves, flanges, and screwed pipe.

11 Data Uncertainty

Data uncertainty is inherent in the analysis addressed in this procedure. An integral part of the analysis procedures is the investigation, documentation, and mitigation of sources of uncertainty in data collected for inventory assessment purposes and the analysis of that data, including but not limited to calculations, gas measurement procedures, and shut-in pressure stabilization time.

END of Requirements

Definitions

The following definitions are consistent with the BOP process which relates to the accounting and treatment of storage gas.

- **Inventory**: All gas molecules in the storage reservoir expressed in a volume at standard temperature and pressure.
- **Adjustment(s)**: A volume of gas that impacts storage Inventory deriving from meter errors, fuel usage, diffuse gas losses and/or other operational factors.
- **Non-Recoverable Gas**: A volume of gas which supports the storage cycle under stabilized pressure conditions but cannot be recovered economically upon field abandonment. The initial determination of Non-Recoverable Gas will be made at or after the abandonment of the storage reservoir begins excluding volumes previously deemed Non-Recoverable Gas and written down. Any identified gas volume which is deemed Non-Recoverable Gas shall be written down at the time a determination of such volume is made (pursuant to XX Policy).
- **Migrated Gas**: A volume of gas believed to have been present in a storage reservoir which subsequently has left the storage reservoir and no longer supports its cyclic storage operation. Any Identified gas volume which is deemed Migrated Gas shall be written down.
- **Identified**: The nature or the origin of the Adjustment, Non-Recoverable or Migrated Gas volume(s) is known to a Reasonable Engineering Certainty. No further research is required.

- **Inconsequential**: To a reasonable person, there is lack of worth or importance, and it is trivial in relation to the lowest level of external financial reporting. Or, lacking in worth or importance as deemed by a reasonable person.
- **Consequential**: To a reasonable person, it has magnitude or importance. Or, having magnitude or importance as deemed by a reasonable person.
- **Unresolved/Loss Contingency**: Items that require further research and/or additional data to determine proper classification as to a possible gain or loss and whose ultimate resolution depends upon whether one or more future events occur or fail to occur. The occurrence of such events can range from Probable to Remote as follows:
    - **Probable**. The future event or events are likely to occur.
    - **Reasonably Possible**. The chance of the future event or events occurring is more than Remote but less than Probable.
    - **Remote**. The chance of the future event or events occurring is slight.
- **Annual Inventory Report**: An annual analysis of the gas storage Inventory including, where applicable, Adjustments, Migrated Gas and Non-Recoverable Gas in each storage reservoir owned and/or operated, or in which an interest is owned by PG&E, based on operating data and engineering studies.
- **Reasonable Engineering Certainty**: A conclusion arrived at by a qualified engineer using all the pertinent available information and employing industry accepted engineering techniques and scientific concepts.

In addition to the terms identified above, a number of practical terms are used in this report to describe operational issues related to management of storage inventory. These terms identify portions of the booked gas volume which do not exhibit a pressure response in the storage reservoir during the semi-annual shut-in tests. The terms and their definitions are as follows.

- **Non-Effective Gas**: The volume of gas that does not exhibit a pressure response in the storage reservoir when a pressure decline analysis (PDA) is performed based on the fall and spring shut-in pressure data which, in general, are not indicative of fully stabilized storage reservoir conditions.
- **Impounded Gas**: That portion of the Non-Effective Gas which supports the storage cycle under stabilized pressure conditions but is not readily producible during the operating withdrawal cycle.
- **Non-Effective Gas Calculation**: The volume of Non-Effective Gas for an operating cycle is determined graphically by performing a PDA. The analysis involves measuring the volume of gas withdrawal from a storage reservoir and well shut-in pressures before and after withdrawal takes place. After plotting the starting and ending total Inventory with the corresponding bottom hole pressures corrected to account for the departure from the ideal gas law, a straight line is drawn through the points and extrapolated to zero psi. This line is used to determine the Non-Effective Gas volume for the operating cycle.
- **Pore Volume Ratio**: The ratio of current pore volume compared to the original pore volume.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

GSAM Standard 8 Reservoir Integrity Management

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

PROCEDURE O11, GAS SAMPLING OBSERVATION AND STORAGE WELLS APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix P12 in Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix P12 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Design and Specifications for Construction of Natural Gas Storage Wells

Summary

Purpose: This standard provides requirements, specifications and procedures for the design and construction of natural gas storage wells.

What: This is to document the design and specifications for construction of natural gas storage wells.

Why: Standard designs and specifications for storage well abandonment ensure a consistent approach is employed, that has been developed by SMEs as the optimum technical and compliance solution for PG&E.

When: This applies to new wells and reworks.

Target Audience

Gas Storage Asset Management (GSAM)

Safety:

n/a

Design and Specifications for Construction of Natural Gas Storage Wells

TABLE OF CONTENTS

Requirements

1. General

This standard defines requirements for the design and construction of natural gas storage wells operated by PG&E. It applies to the drilling and completion of new wells, the remediation and reconditioning of existing wells (reworks), and the abandonment of wells

2. Wellhead Equipment and Valves

Wellhead equipment shall comply with Standard E1A, Wellhead Equipment Design Standard. New and replacement wellhead equipment should conform to API 6A, Specification for Wellhead and Christmas Tree Equipment.

3. Well Casing

The design of well casing shall comply with Standard E1B, Tubular Design Standard.

4. Casing Cementing Procedures

Cementing of well casing shall comply with Standard E1C, Cementing Standard.

5. Completion and Stimulation

Completion and stimulation operations shall be designed and conducted to ensure that the integrity of the storage reservoir, caprock, well tubulars, casing cement, and wellhead equipment is preserved. In particular, loads generated during completion and stimulation operations should be compared to wellhead and tree pressure limits and to casing and tubing strengths to ensure that the minimum safety factors in Practice 1B are met.

The design and installation of completion tubing shall comply with Practice 1B, Tubular Design Standard.

Baseline cased hole logging should be performed on all wells as described in Standard 9, Appendix 1 Well Logging Criteria for New, Redrilled, and Reworked Wells, Table 2.

Fracture stimulation treatment requires special considerations and should follow API guidance documents API HF1, API HF2, and API HF3. Following fracture treatment, offset wells and the reservoir should be monitored for indications of a loss of well integrity.

6. Well Remediation (Reworks)

Wells suspected of having impaired mechanical integrity will be evaluated according to Procedure D, Remedial Options and Decision Tree. Depending on the degree of impairment, consideration should be given to isolating the well with kill weight brine and monitoring wellhead pressures and fluid levels until well remediation begins.

Existing well records, including casing inspection logs and mechanical integrity test data, should be reviewed when planning well remediation work. Well remediation planning should consider anticipated storage reservoir pressures prior to and during well remediation activities.

Prior to returning a reworked well to service, the well’s integrity should be reassessed. Depending on the nature of the well work performed, casing inspection logging and/or pressure testing should be performed.

7. Well Closure (Plugging and Abandonment)

Plugging and abandonment of wells shall comply with Standard E1D, Well Abandonment Standard.

8. Environmental, Safety, and Health

API 1171 requires several design and construction safeguards that are met with this plan and the companion guidance documents:

1. Safeguards to the environment, safety, and health of workers and the public shall be incorporated into well design and well work activities.

2. Actions shall be taken to protect surface water and groundwater resources in the design, drilling and servicing of a well.

3. Worksite conditions shall be monitored during well construction and well work activities in order to protect the environment and the safety and health of workers and the public.

4. An emergency response plan shall be in effect as described in Section 10 of the API 1171. This is addressed in Section 16 of this plan.

5. Design should consider threats that are associated with protecting water bearing zones, water table changes, flooding, earthquakes, lightening, or other act of God type events.

Well work, construction, or any other work activity for PG&E includes preparation of an Environmental Release to Construction (ERTC) for review by PG&E's Environmental Field Specialist (EFS) prior to the work activity. This process is very similar to an environmental impact review as recommended for drilling operations in API 1171. The EFS will provide a formal approval, along with any required monitoring activities and/or preparation work required for the specific project approved to provide safeguards to the environment and compliance with local environmental regulations. Additionally, well work and construction are performed in alignment with PG&E's Safety and Health and Contractor Safety Programs.

API 49, 51R, 54, and 76 identify additional safeguards for storage well design and well work activities, as referenced in API 1171.

PG&E's Gas Emergency Response Plan (GERP) which is updated annually and includes a Well Control Tactical Considerations Plan, provides emergency response procedures during well design, construction and well work activities. A blowout contingency plan shall be in place that is PG&E specific as outlined in API 1171 Section 10.6.3.

9. Testing and Commissioning

New storage wells, new production casing, inner strings and tubing installations, and wells in which the production casing is modified shall undergo pressure testing and baseline inspection logging to demonstrate mechanical integrity.

Production casing, inner string, and tubing used as a primary or secondary barrier shall be pressure tested to 115% of maximum allowable operating pressure (MAOP) in accordance with Procedure Z, Well Integrity Testing Regime Process, and applicable regulatory requirements. New casing shall be tested prior to drilling out the shoe, and existing casing shall be tested with a plug set as close as practical to the top of the storage formation. On wells with tubing-packer completions, the tubing-casing annulus shall be pressure tested to meet regulatory requirements.

Loads generated during pressure testing should be compared to wellhead and tree pressure limits and to casing and tubing strengths to ensure that the minimum safety factors in ~~Practice~~ Standard E1B, Tubular Design Standard are met.

Baseline inspection logging will be performed in accordance with Procedure S15, and Procedure Z.

10. Monitoring of Construction Activities

Development and replacement field activities that affect well design and construction should be evaluated prior to job execution and monitored during execution to verify and document that mechanical integrity of the well is maintained. All well activities should be supervised at the job site by competent personnel to ensure company procedures, regulatory and safety regulations, and any necessary geologic and engineering aspects of the well work are followed. The skills of such personnel and suitability for any equipment used should be documented – For personnel refer to Procedure AH, and for equipment refer to Standard AG.

Company procedures should be written clearly to allow competent personnel to follow the procedure consistently to achieve desired objectives. Current procedures shall be available and readily accessible to operations, maintenance, and storage personnel in either paper or electronic format. These procedures should outline monitoring activities. General procedures may be adapted for integrity monitoring activities. Training should be provided for any personnel (including contractors) designated to monitor storage wells during field activities which affect well design and construction.

API 1171 requires recordkeeping of the Monitoring of Construction Activities as outlined in Section 1.11 below.

11. Recordkeeping

Well construction, completion, and well work records shall be maintained for the life of the storage facility. Well construction shall be documented in wellbore schematics and wellhead diagrams, as described in Procedure F2, Creating and Updating Storage Wellbore Schematics and Procedure G, Creating and Updating Storage Wellhead Diagrams, respectively.

Specific records to be maintained shall include, as applicable, the following items listed in Section 6.11.1 of API RP 1171: The numbering below corresponds to this section of API RP 1171.

- *6.2 Wellhead Equipment and Valves*

— Material and test records

— Design evaluations

— Emergency shut-down valve evaluation

— Inspection and repair records

— Wellhead Schematic

- *6.3 Well Casing*

— Material and test records

— Design evaluations

— Setting depths of all strings of casing

— Connection design evaluation

— Connection torque verification

- *6.4 Casing Cementing Practices*

— Blends, additives and volumes pumped

— Volume of cement circulated to surface

— pH of mix water and water temperature

— Pump and displacement rates and displacement times

— Pre-flush type and volume pumped

— Type of float and centralization equipment and location in string

— Theoretical and actual displacement volumes

— Detail of remedial cementing work performed

— Cement service company's field report and log of job

— Logged cement placement and any evaluation of quality of seal

- *6.5 Completion and Stimulation Considerations*

— Service company field reports and job logs

— Location and description of stimulation treatments

— Composition and volumes of any fluid used

— Cementing reports (as detailed in 6.4 Casing Cementing Practices)

— Type of equipment used and location in well

— Cased hole correlation logs

— Post treatment monitoring data and analysis

- *6.6 Well Remediation*

— Cementing reports (as detailed in 6.4 Casing Cementing Practices)

— Type of equipment used and location in well

— Well logs

— Work over and recompletion reports

- *6.7 Well Closure*

— Equipment removed from well

— Cementing reports (as detailed in 6.4 Casing Cementing Practices)

— Plugging records filed with local regulatory authorities

- *6.9 Testing and Commissioning*

— Mechanical integrity test data

— Pressure test data

— Type and amount of fluid in annulus of tubing packer completion

— Casing inspection logs

- *6.10 Monitoring of Construction Activities*

— Received equipment and material specifications

— Changes in well construction from original well design

— Rig and service company field tickets and job logs

— Mud records, mud log, driller's logs, geolograph records, daily drilling or servicing reports

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM integrity management engineers

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

GSAM Standard E1A, Wellhead Equipment Design Standard

GSAM Standard E1B, Tubular Design Standard

GSAM Standard E1C, Cementing Standard

GSAM Standard E1D, Well Abandonment Standard

Procedure S15, Casing Inspection Logging and Data Assessments

Procedure Z, Well Integrity Testing Regime Process - Production Casing

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISSION

This replaces Appendix E procedure 1 of the Underground Storage Risk and Integrity Management Plan, Publication Date: Rev 5

Document Approver

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Document Owner

Lucy Redmond, Director, GSAM

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REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix E to this standalone standard	Minor language changes were made for clarity. No content changes were made

Wellhead Equipment Design Standard

Summary

Purpose: This standard provides requirements, specifications and procedures for the design and construction of natural gas storage wells.

What: This is to document the design and specifications for construction of natural gas storage wells.

Why: Standard designs and specifications for storage wells ensure a consistent approach is employed, that has been developed by subject matter experts (SMEs) as the optimum technical and compliance solution for PG&E.

When: This applies to new wells and reworks.

Target Audience

Gas Storage Asset Management (GSAM)

- Reservoir Engineers (RE)
- Reservoir Specialists (RS)
- Integrity management engineers
- Well work project managers
- Technical work supervisors

Safety:

n/a

Wellhead Equipment Design Standard

TABLE OF CONTENTS

1. Scope

1.1. Purpose

The purpose of the Wellhead Equipment Design Standard (WEDS) is to ensure that wellhead and associated equipment design performed by PG&E meets internal and regulatory requirements and the well control and asset safety risks are consistent with internal and regulatory requirements.

The WEDS adheres to the following California (CalGEM), Federal and other local jurisdictions regulations. Refer to Section 3 of GSAM Standard 1 and the Compliance Requirement / Regulatory Commitment section at the end of this document for details.

1.2. Application

The WEDS is to be applied for:

- the design of new wells

- analysis of wells scheduled for remediation and reconditioning
- analysis of existing wells

The WEDS is to be utilized for both casing flow and tubing flow (tubing packer completions) wells.

1.3. Contents

The WEDS contains the design factors and considerations required to perform wellhead equipment design or design verification. Operating procedures produced separately to the WEDS detail the steps required to complete a wellhead equipment design.

1.4. Deviations from Design Standard

Well abandonments that do not meet the minimum requirements of the well abandonment standard require approval from a PG&E Officer.

Provisions containing the word ‘‘should’’, “may” or other non-mandatory language will be considered mandatory where denoted by a footnote. Depending on the degree of deviation, a risk assessment may be required as well as approvals from state, federal and other local jurisdictions.

Wellhead equipment designs that exceed the requirements of this standard are acceptable; however, the well designer should[1] evaluate the additional costs and benefits associated with such a design.

2. Wellhead Equipment and Valves

2.1. General

The wellhead acts as an interface between the casing and tubing strings in the wellbore and the surface facilities. The wellhead provides a suspending point for the casing and tubing strings running through the wellbore and also acts to contain the pressure inside the casing and tubing strings. The wellhead can be used for pressure monitoring for casings and annuli between different casing and tubing strings.

Newly installed wellhead equipment, including associated equipment (fittings, flanges, valves) should conform to API 6A.

[1] As per API RP 1171

2.2. Wellhead Equipment Design

Newly installed wellhead equipment shall allow for full-diameter wellbore entry or appropriate well control practices must be employed to access and/or isolate the wellbore from the storage reservoir. A review of the well records shall[1] be conducted at the planning stage of a well maintenance. The goal of this review is to assess whether the level of wellbore access allowed by the existing wellhead is sufficient to conduct the planned operations.

Valves isolating the well from the pipeline system (including jurisdictional or regulated) and valves allowing for wellbore access shall be part of the wellhead equipment.

All wellhead assembly ports should[1] be equipped with valves, blind flanges or similar equipment.

2.3. Pressure Rating

Wellhead equipment operating pressure ratings shall[1] exceed maximum anticipated operating pressure. Additionally, the following aspects should[1] be considered and evaluated as part of the well head equipment design (per API 1171 Section 6.2.3):

- Treating and stimulation pressures
- Flow rates
- Chemical composition of produced and stimulation fluids
- Anticipated solid production
- Anticipated increases in maximum operating pressure
- Intended flow path
- Anticipated need for tubular/annular pressure monitoring

2.4. Existing Equipment

Existing equipment is considered acceptable if it can contain the maximum operating pressure. Before any increase in operating pressure beyond the historical maximum, suitability of existing equipment shall[1] be evaluated.

2.5. Wellhead Emergency Shutdown Valves

Although automatic or remote-actuated emergency shut down valves (wellhead, side-gate, or subsurface) are usually not required on storage wells, the need for any type of emergency shut down valve shall[1] be evaluated considering the following (per API 1171 Section 6.2.5):

- Whether the well is an “active observation well” recognized by CalGEM, as defined by PRC §3008 (c), or is a “gas storage well” as defined by PRC §3180 (a)
- Distance from dwellings, buildings intended for human occupancy or well-defined outside areas where people assemble such as campgrounds, recreational areas or playgrounds
- Gas composition, total fluid flow and maximum flow potential
- Distance between wellheads, or between a wellhead and other facilities, and access for drilling and service rigs and emergency services
- Added risks created by installation and maintenance requirements of safety valves
- Risk to and from the well related to transport infrastructures (roadways, airports, etc...) and industrial facilities
- Alternative protection measures provided by barricades and railings, or other such devices
- Present and anticipated development of the surrounding area, topography and regional drainage systems and environmental considerations

Additional guidance on the design, installation and testing of subsurface safety valves is provided in API 14A and 14B.

3. General and Location Specific Wellhead Equipment Design

The wellhead equipment assembly consists of various wellhead components, including a casing head, one or more spool sections, a tubing head adapter, and the Christmas tree assembly which includes, at a minimum, a master gate valve, studded cross, and wing valve.

Wellhead Equipment Design Standard

Previously-installed PG&E wellhead assemblies generally consist of the following components:

- Casinghead welded to surface casing
- Double studded adapter (DSA) with additional production casing seals
- Casing spool (if inner string is installed)
- Tubing head (spool) with casing flow wing valves
- Tubing head adapter
- Tree assembly, including
    - Master valve
    - Studded cross
    - Wing valve (one or two)
    - Crown (swab) valve (if installed)
    - Tree cap

Newly installed PG&E wellhead equipment assemblies typically consist of the following components:

- Casinghead welded to surface casing
- Multibowl spool
- Tubing head adapter
- Tree assembly, including
    - Lower and upper master valves
    - Studded cross
    - Two wing valves
    - Tree cap

Wellhead Equipment Design Standard

The typical components found on PG&E wells may include:

(a) Casing head:

- Casing head with two outlets
- Bull plug
- Nipple
- Ball valve
- API ring
- Casing slips and packing

(b) Tubing head:

- Tubing head with flanged outlets
- Double studded seal flange
- Flanged expanding gate valves
- Companion flanges
- Tubing hanger
- Gate valves
- API rings

(c) Christmas tree assembly:

- Master gate valve
- Single studded adapter
- Studded cross
- Flanged expanding gate valve
- Christmas tree cap/ wireline adaptor
- Companion flanges
- API rings

- Bull plug tapped ½”
- Nipple

4. Required Documentation

4.1. Well Work Records - Minimum Requirements

As per API RP 1171, records of well completion (as-built), well construction and well work activities shall[1] be maintained for the life of the facility. These records shall[1] include, as applicable and available, the items listed below.

Wellhead Equipment and Valves

- Material and test records.
- Design evaluations.
- Emergency shutdown valve evaluation.
- Inspection and repair records.

For traceability tracking, all pressure test records conducted in the field for new installation or component replacement should include the following:

- Name of company and supervisor overseeing pressure testing
- Date of pressure test
- Serial number and brief description of component(s) being tested

4.2. Record Keeping

The wellhead equipment design documentation shall be stored in the PG&E well files for the life of the storage facility.

END of Requirements

Definitions

Refer to definitions in API 1171 and CalGEMs regulations.

Implementation Responsibilities

GSAM integrity management engineers

Wellhead Equipment Design Standard

Governing Document

GSAM Standard 1

Compliance Requirement / Regulatory Commitment

Regulatory codes listed in GSAM Standard 1, Section 3.

API Specification 14A - Subsurface Safety Valve Equipment

API Recommended Practice 14B - Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems

Reference Documents

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

GSAM Standard E1, Design and Specifications for Construction of Natural Gas Storage Wells

GSAM Standard E1B, Tubular Design Standard

GSAM Standard E1C, Cementing Standard

GSAM Standard E1D, Well Abandonment Standard

Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs”. API RP 1171, 2015

“Specification for Wellhead and Christmas Tree Equipment”. API SPEC 6A 21st Edition 2018

Appendices

n/a

Attachments

n/a

Document Recission

This replaces Appendix E1A of the Underground Storage Risk and Integrity Management Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Larry Kennedy, Strategic Planning Chief, GSAM

Revision Notes

Where?	What Changed?
Converted RIMP Appendix E1A to this standalone standard	Minor language changes were made for clarity. No content changes were made

Tubular Equipment Design Standard

Summary

Purpose: This standard provides requirements, specifications and procedures for the design and construction of natural gas storage wells.

What: This is to document the design and specifications for construction of natural gas storage wells.

Why: Standard designs and specifications for storage well abandonment ensure a consistent approach is employed, that has been developed by SMEs as the optimum technical and compliance solution for PG&E.

When: This applies to new wells and reworks.

Target Audience

Gas Storage Asset Management (GSAM)

Safety:

n/a

Tubular Equipment Design Standard

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SUBSECTION TITLE PAGE

Tubular Equipment Design Standard

1. Scope

1.1. Purpose

The purpose of the Tubular Design Standard (TDS) is to ensure that casing and tubing design performed by PG&E meets internal and regulatory requirements and does not pose a well control or safety risk.

The TDS adheres to California (CalGEM), Federal and other local jurisdictions regulations. Refer to Section 3 of GSAM Standard 1 and the Compliance Requirement / Regulatory Commitment section at the end of this document for details

1.2. Application

The TDS is to be applied for:

- the design of new wells
- analysis of wells scheduled for remediation and reconditioning
- analysis of existing wells

The TDS is to be utilized for both casing flow and tubing flow (tubing packer completions) wells.

1.3. Contents

The TDS contains the approved design factors and load cases required to perform casing and tubing design or design verification. Operating procedures produced separately to the TDS detail the steps required to complete a casing or tubing design.

The design documentation specified in Section 6.0 shall apply to all casing and tubing designs.

1.4. Deviations from Design Standard

Tubular designs that do not meet the minimum requirements of the TDS require approval from a PG&E officer.

Provisions containing the word ‘‘should’’, “may” or other non-mandatory language will be considered mandatory where denoted by a footnote. Depending on the degree of deviation, a risk assessment may be required as well as approvals from state, federal and other local jurisdictions.

Tubular Equipment Design Standard

Tubular designs that exceed the requirements of this standard are acceptable; however, the well designer should[1] evaluate the additional costs and benefits associated with such a design.

2. Design Premise

2.1. Conductor Casing Design

The purpose of the conductor casing is to support unconsolidated surface deposits. The conductor size and grade should[1] be sufficient to accommodate the drilling of the surface hole and installing the surface casing.

2.2. Surface Casing Design

The purpose of the surface casing is to protect ground water and to ensure safe drilling operations until the next casing string is set. The surface casing shall be of sufficient size to accommodate the subsequent drilling and setting of casing strings. The weight and grade shall be sufficient to meet the load cases specified in Section 4.

Surface casing shall be cemented into or through a competent bed and at a depth that will allow complete well shut-in in the event of a well control situation.

2.3. Intermediate Casing Design

Intermediate casing may be required on a well by well basis to provide protection against abnormal hole conditions such as cave-ins, lost circulation or abnormal pressure. The intermediate casing shall be of sufficient size to accommodate the subsequent drilling and setting of casing strings. The weight and grade shall be sufficient to meet the load cases specified in Section 4.

2.4. Production Casing Design

The production casing is for the purpose of isolating the storage formation/zone and providing a conduit between the storage zone and the surface. The production casing shall be of sufficient size to accommodate the production liner, production tubing and downhole safety valve (if installed) and to accommodate the desired withdrawal flow rate on casing flow wells. The weight and grade shall be sufficient to meet the load cases specified in section 4 and also be compatible with proposed fluid compositions.

The production casing setting depth is generally near the base of the cap rock shale above the storage zone, however, in certain circumstances the production casing setting depth may be at the total depth of the well.

[1] As per API RP 1171

Remedial inner casing strings installed inside existing production casing shall be designed as production casing.

2.5. Production Liner & Gravel Pack Design

The production liner, in conjunction with the gravel pack, is for the purpose of filtering the storage formation fines from entering the wellbore to minimize sand production.
Design Considerations:

1. For open hole completion, wire-wrapped screen is normally used to allow maximum exposure to the formation
2. Screen size is determined as follows:
    a. From the core (or appropriate historical field data) having the smallest particle, determine the d50 (50%) particle size of the cumulative passing through sieve analysis
    b. Use Saucier's method to determine the grave size (6 x d50)
    c. The final design gravel sizes straddle the gravel size determined in above calculation
    d. Use 75% the smallest gravel size for the screen opening.
3. The length of the production liner depends on the formation thickness and should consist of the following from top to bottom:
    a. Liner hanger
    b. Gravel packing equipment
    c. One joint of blank casing
    d. Shear-out safety joint
    e. One joint of blank casing
    f. A slim pack pre-pack wire wrapped screen
    g. The wire-wrapped screen length should be the difference of total depth of the hole and the production casing shoe, less 5' +/-.
    h. O-ring seal sub

i. Gravel pack set shoe.

2.6. Production Tubing Design

The production tubing design will depend on whether the well is completed for casing flow or tubing flow.

In addition to the tubing design described in this standard a tubing-packer loading analysis shall be performed by the service company for all retrievable packer installations or stabbing of tubing into a liner hanger or permanent packer. The tubing packer loading analysis should consider the same load cases as the production tubing design.

2.6.1. Casing Flow

The production tubing serves as a means to lift produced water from the bottom of the well bore during withdrawal operation. The production tubing may also be used for gas flow during withdrawal and for gas injection.

The tubing size will depend on storage operations, reservoir performance, fluid dynamics and characteristics. The weight and grade shall be sufficient to meet the load cases specified in section 4.

For wells having downhole safety valves (DHSVs), the production tubing design shall consider the DHSV packer which is generally set at approximately 250’ below ground.

2.6.2. Tubing Flow

The production tubing serves as the conduit for gas injection and gas withdrawal. In tubing flow situations, the production packer is generally set within 100’ of the storage zone.

The tubing size should be designed to accommodate the desired withdrawal rate. The length of the tubing should be hung 10 to 15’ from bottom of the production liner. The weight and grade shall be sufficient to meet the load cases specified in section 4.

For wells having downhole safety valves (DHSVs), the DHSV is set at approximately 250’ below ground.

2.7. Connections

For surface casing and intermediate casing, API connections should generally be specified unless there is a compelling reason to use a non-API connection.

For production casing and tubing, the selected tubular connection shall be designed to maintain a gas seal during injection and withdrawal operations and during subsequent well work operations. Tubular design using non-API connections shall use published performance data supplied by the manufacturer. Triaxial design limit plots should be requested from the connection manufacturer. The ability to obtain crossovers, float equipment, and completion equipment should be considered when specifying non-API connections.

2.8. Tubular Installation

Storage, transportation, lifting and installation shall be in accordance with the manufacturer's recommendations and API RP 5C1

Casing and tubing connection make up shall be in accordance with manufacturer specifications or API SPEC 5CT. Thread compound or lubricant shall be compatible with wellbore conditions and shall conform to manufacturer's recommendations or API RP 5A3

3. Design Factors

3.1. Design and Safety Factors

The load (i.e., pressure, force or stress) calculated for the load cases in Section 4.0 shall be divided by the strength/rating of the affected tubular component to calculate a safety factor (SF).

SF = Strength Rating / Load

3.2. Tubular Strength Ratings

For the installation of new tubing or casing, tubular strength ratings shall be based on the latest edition of API Technical Report 5C3 (ISO10400). For non-API tubular connections, published manufacturer data shall be used.

For ongoing verification of mechanical integrity for existing wells, the API historical internal pressure rating (Barlow formula) and modified ASME B31G burst formula may be used as described elsewhere in the PG&E Underground Storage Risk and Integrity Management Plan guidance document library.

3.2.1. Burst

Uniaxial burst (internal pressure) design shall be based on the lowest of the following four internal pressure ratings shown in the latest edition of the API Technical Report 5C3 (ISO10400):

1. Pipe body internal yield
2. Connection internal yield
3. Connection pressure leak resistance
4. Pipe body ductile rupture

The well designer should be aware that the ratings for items 2, 3 and 4 above may be lower than the Pipe body internal yield (item 1), which is the burst rating most commonly shown in reference materials.

Pipe body internal yield ratings shall use API formulas which are based on 87.5% of nominal wall thickness (allowable pipe manufacturing tolerance), unless a caliper survey or ultrasonic inspection is used to measure actual wall thickness.

3.2.2. Collapse

API collapse strength ratings shall be derated for tension in accordance with API TR 5C3.

3.2.3. Axial

Axial analysis shall be based on the minimum yield strength of the casing/tubing grade.

3.2.4. Triaxial

Triaxial analysis shall be based on the minimum yield strength of the casing/tubing grade.

4. Load Analysis

Casing and tubing design shall consider all loads that are reasonably expected to occur during tubular installation, subsequent drilling and completion operations, gas storage operations, and well work (reworks, assessments, stimulations, abandonment) during the life of the well.

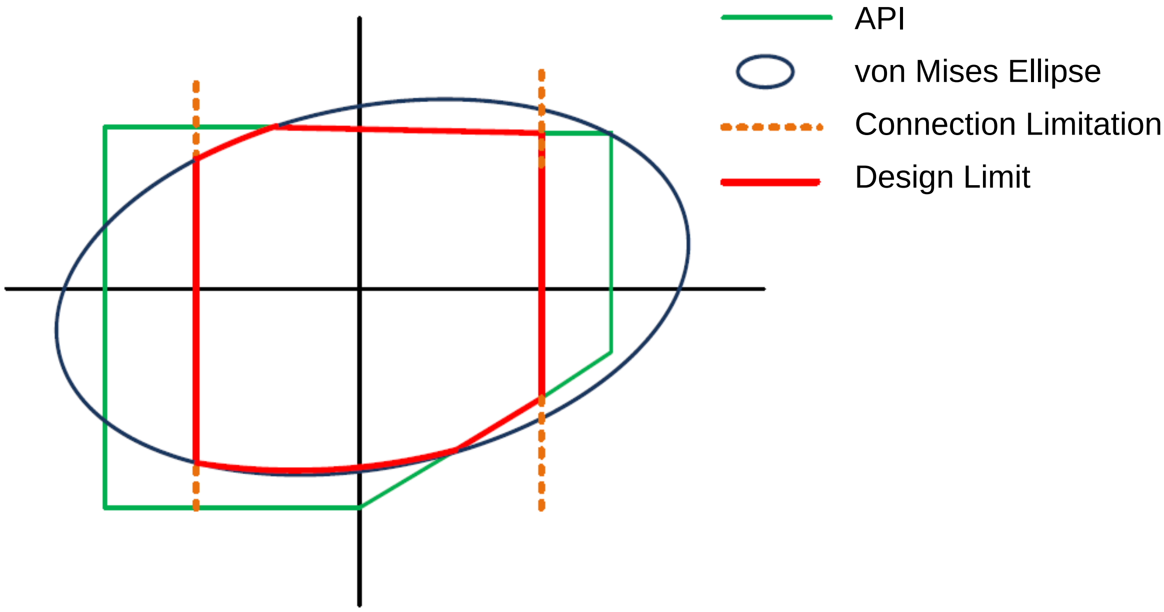
A tubular design analysis will be carried out for all new wells and wells scheduled for remediation and reconditioning. For existing wells, a sampling approach can be taken whereby, a single well design can be applied to multiple wells as long as the well construction satisfies a common set of design parameters.

4.1. Calculation Methodology

All wells should be analyzed using both uniaxial (burst, collapse and axial) and triaxial loading.

Triaxial loading shall use the von Mises methodology for combined pressure and axial loading. The von Mises triaxial load evaluation allows the casing design to be analyzed under a combination (more realistic) of loads. The design limit takes into account the API, von Mises and connection (coupling) design values and utilizes the minimum prescribed limit for each load – burst, collapse, tension & compression.

The design limits are shown in the graphical representation below where the X-axis is axial force (compression is <0, tension is >0) and the Y-axis is the effective differential pressure (collapse is <0, burst is >0). The governing design limit is defined by the solid red line; all load cases analyzed that are deemed to be acceptable will fall inside of the red line.



Software such as Landmark's *StressCheck* is available to perform triaxial analysis and is widely accepted across the oil and gas industry. For wells where thermal changes to the tubulars need to be taken into account, the software *WellCat,* also produced by Landmark, can be utilized.

Tubular Equipment Design Standard

4.2. Casing Load Cases

The following load cases shall be evaluated:

Burst Load Cases

Burst Load Cases	Surface Casing	Intermediate Casing	Production Casing (drilled through)	Production Casing
Drilling: Gas Kick – Displacement to Gas	X	X	X	N/A
Drilling: Pressure Test to Maximum Anticipated Surface Pressure (MASP)	X	X	X (115% of MAOP)	X (115% of MAOP)
Operations: Shallow Tubing Leak - Injection	N/A	N/A	X	X
Operations: Casing Flow Withdrawal	N/A	N/A	X	X
Operations: Shallow Tubing Leak – Tubing Flow Withdrawal	N/A	N/A	X	X
Well Work: Pressure Test – Block Testing	N/A	N/A	X	X
Well Work: Gas kick – circulate out to kill well	N/A	N/A	X	X

Collapse Load Cases

Collapse Load Case	Surface Casing	Intermediate Casing	Production Casing/Liner (drilled through)	Production Casing/Liner
Installation: Cementing	X	X	X	X
Drilling: Lost Returns – with Mud Drop to balance pressure at loss zone	X	X	X	N/A
Operations: Full Evacuation	N/A	N/A	X	X

Tubular Equipment Design Standard

Axial Load Cases

Axial Load Case	Surface Casing	Intermediate Casing	Production Casing/Liner (drilled through)	Production Casing/Liner
Installation: Running in Hole	X	X	X	X
Installation: Overpull	X	X	X	X
Installation: Green Cement Pressure Test	X	X	X	X
Operations: Injection Cooling, Withdrawal Heating	N/A	N/A	X	X
Well Work: Packer Release	N/A	N/A	X	X
Well Work: Stimulation (if applicable)	N/A	N/A	X	X

4.3. Tubing Load Cases

The following load cases shall be evaluated:

Load Case	Description
Operations: Gas Injection	Burst
Operations: Gas Withdrawal	Burst
Operations: Shut-in	Burst
Operations: Shallow Tubing Leak – Gas Injection	Collapse
Well Work: Bullhead Kill	Burst
Well Work: Tubing Pressure Test	Burst
Well Work: Casing (Annulus) Pressure Test	Collapse
Completion/Well Work: Overpull - Packer Installation/release	Axial

5. Special considerations

5.1. Bending Loads

Axial loads (tension and compression) due to bending shall be considered during axial and triaxial design using the following formula:

- Additional Tensile/Compressive Load due to Bending (lbs.) = 218 x OD x DLS x A
- OD = Outer pipe diameter (inches)
- DLS = Dogleg Severity (°/100 ft)
- A = Cross-sectional Area (sq. in)

5.2. Casing Wear / Heat-Checking

Casing wear and heat-checking can significantly reduce burst and collapse resistance.

Centering of the rig over the hole and use of a wellhead wear bushing shall be performed to avoid shallow casing wear.

Directional design and torque and drag analysis should be used to limit side loading pressures to ≤2,000 psi whenever possible to minimize casing wear during drilling. Non-rotating drill pipe protectors should be employed if side loading cannot be reduced with other means.

Consideration should be given to using the next larger wall thickness for casings that will be drilled through for extended periods.

For production casing that is drilled though for more than 14 days, consideration should be given to running an ultrasonic wall thickness log (e.g., USIT) or caliper survey to determine remaining wall thickness and calculate new strength ratings prior to placing the well in service. The results may dictate the need for a tieback or scab liner.

5.3. Corrosion

PG&E periodically runs casing inspection logs on their gas storage wells. The wall thickness results can be compared against the maximum allowable wall thickness loss (calculated from the tubular design analysis). The resulting analysis may require preventative measures be applied to ensure well integrity, such as: installing an inner string or casing patch, imposing operating limits, or modifying the annular fluid. Historical casing corrosion results should be utilized when designing a new well to allow sufficient allowance for wall loss during the life of the well.

The frequency of wall thickness monitoring must be evaluated using risk assessment.

5.4. Slotted Liners / Wire-wrapped Screens

The axial strength of slotted or perforated liners shall be derated based on the amount steel removed.

The blank portions of slotted liners and wire-wrapped screens shall be designed to meet the same burst and collapse loads as a blank cemented casing would be designed.

5.5. Landing Strings

Casing landing strings shall meet the axial load requirements of the upper most casing string section.

5.6. Rotating Casing or Liner

If casing or liner will be rotated during installation, the pipe body and connections shall be designed to withstand expected torsional and bending loads.

6. Required Documentation

6.1. Well Work Records - Minimum Requirements

As per API RP 1171, records of well completion (as-built), well construction and well work activities shall be maintained for the life of the facility. These records shall include, as applicable and available, the items listed below.

6.1.1. Well Casing

- Material and test records.
- Design evaluations.
- Setting depths of all strings of casing.
- Connection design evaluation.
- Connection torque verification.

6.1.2. Completion and Stimulation Considerations

- Service company field reports and job logs.
- Location and description of stimulation treatments.
- Composition and volumes of any fluid used.
- Cementing reports.
- Type of equipment used and location in well.
- Cased hole correlation logs.

- Post-treatment monitoring data and analysis.

6.1.3. Well Remediation

- Cementing reports.
- Type of equipment used and location in well.
- Well logs.
- Workover and recompletion reports.

6.1.4. Well Closure

- Equipment removed from well.
- Cementing reports.
- Plugging records filed with local regulatory authorities.

6.1.5. Testing and Commissioning

- Mechanical integrity test data.
- Pressure test data.
- Type and amount of fluid in annulus of tubing and packer completion.
- Casing inspection logs.

6.1.6. Monitoring of Construction Activities

- Received equipment and material specifications.
- Changes in well construction from original well design.
- Rig and service company field tickets and job logs.
- Daily drilling and servicing reports, geolograph records, and driller's log.
- Mud records.
- Wireline logs and mud logs.

6.2. Tubular Design Report - Minimum Requirements

A summary report should be provided for each tubular analysis, containing the following information:

- Casing Scheme (Size, Weight, Grade, Connection and depths for string section)
- List of Load Cases Considered

- Internal/External Loadings Used
- Assumptions/Uncertainties
- Minimum Safety Factors (Burst, Collapse, Axial) for each tubular string
- Weak Point Identification
- Kick Tolerance (if casing is drilled through)
- Limitations, including
  - Packer Fluid Density/Max. Allowable Mud Weight
  - Max. Allowable Dogleg Severity
  - Maximum allowable running speed
  - Pressure Testing
  - Max. Allowable Evacuation Depth
  - Corrosion/wear wall loss allowance
- For StressCheck analysis the following will be provided
  - StressCheck Detailed Report
  - Triaxial (Design Limits Plot)
  - Burst, Collapse, Axial loading charts (as appropriate)
- Tubing-Packer loading analysis

7. Record Keeping

The tubular design documentation shall be stored in the PG&E well files for the life of the storage facility.

END of Requirements

Definitions

Refer to definitions in API 1171 and CalGEMs regulations.

Implementation Responsibilities

GSAM

Governing Document

GSAM Standard 1

Compliance Requirement / Regulatory Commitment

Regulatory codes listed in GSAM Standard 1, Section 3.

Reference Documents

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

GSAM Standard E1, Design and Specifications for Construction of Natural Gas Storage Wells

GSAM Standard E1A, Wellhead Equipment Design

GSAM Standard E1C, Cementing Standard

GSAM Standard E1D, Well Abandonment Standard

Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used for Casing or Tubing; and Performance Properties Tables for Casing and Tubing. ANSI/API Technical Report 5C3, 2008 (ISO 10400:2007).

Well Integrity in Drilling and Well Operations. D-010 Rev 4 June 2013, NORSOK – Norwegian Petroleum Industry.

Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. API RP 1171, 2015

Specification for Casing and Tubing. API SPEC 5CT 9th Edition 2011

Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements. API RP 5A3 3rd Edition 2009

- *Recommended Practice for Care and Use of Casing and Tubing.* API RP 5C1 18th Edition 1999
- *ASME B31G-2012 (R2017) Manual for Determining the Remaining Strength of Corroded Pipelines*

Appendices

n/a

Attachments

n/a

Document Recission

This replaces Appendix E1B of the Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

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Revision Notes

Where?	What Changed?
Converted RIMP Appendix E1B to this standalone standard	Minor language changes were made for clarity. No content changes were made

Cementing Standard

SUMMARY

Purpose: This standard provides requirements, specifications and procedures for the design and construction of natural gas storage wells.

What: This is to document the design and specifications for construction of natural gas storage wells.

Why: Standard designs and specifications for storage well abandonment ensure a consistent approach is employed, that has been developed by SMEs as the optimum technical and compliance solution for PG&E.

When: This applies to new wells and reworks.

Target Audience

Gas Storage Asset Management (GSAM)

Safety:

n/a

Cementing Standard

TABLE OF CONTENTS

SUBSECTION TITLE PAGE

Cementing Standard

1. Scope

1.1. Purpose

Cement is an essential component for isolating the gas storage reservoir from hydraulic communication with other porous and permeable formations. This requires placement of competent cement within the annular space between the casing and formation to create a barrier/seal which prevents migration of fluids between the storage zone and any other reservoirs. The purpose of the Cementing Standard (CS) is to ensure that PG&E cementing practices meets internal and regulatory requirements and does not pose a well control or safety risk.

1.2. Application

The CS will be applied to cementing designs for new wells, planned remedial work on existing wells and for abandonment of gas storage completions.

1.3. Contents

The CS contains recommendations that conform to API Recommended Practice 1171 for all cementing that may be required during the life of a gas storage well.

1.4. Deviations from Design Standard

Cement designs that do not meet the minimum requirements of the Cement Standard require approval from a PG&E Officer.

Provisions containing the word ‘‘should’’, “may” or other non-mandatory language will be considered mandatory where denoted by a footnote. Depending on the degree of deviation, a risk assessment may be required and approvals from State, Federal and other local jurisdictions.

Cement designs that exceed the requirements of this standard are acceptable; however, the well designer should evaluate the additional costs and benefits associated with such a design.

2. Cement Quality

As stated in API Recommended Practice 1171, cement should[1] meet quality standards in API 10A and ASTM C150/C150M or exceed the requirements set in these standards.

3. Cement in Well Construction and Remedial Work

Cement slurries for the construction, remediation and plugging of gas storage wells should[1] be properly designed with cement quality and placement techniques to achieve wellbore and reservoir

[1] As per API RP 1171

integrity. Cement properties, including density and water loss, should[1] be designed for the specific conditions of the wellbore to be cemented, considering the water source to be used to mix the cement.

3.1. Conductor Pipe

The conductor pipe, if set in a drilled wellbore, should[1] be cemented in the drilled hole with sufficient slurry volume to allow circulation to surface. If the conductor is driven, no cement is required.

3.2. Surface Casing

Cementing of the surface casing, if technically feasible, should[1] achieve the following: 1) include sufficient excess slurry volume to account for wellbore irregularities and/or formation losses, 2) circulation of slurry back to surface, 3) provide support for the wellhead and casing strings, and 4) isolate and protect groundwater from contamination with fluids from other sources. If cement does not circulate to surface, a top job may be performed to extend the top of cement to the surface. Surface casing should be cemented into or through a competent geologic formation and at a depth that will allow complete well shut-in without fracturing the formation immediately below the casing shoe.

3.3. Intermediate Casing

Any intermediate casing string run in a wellbore should[1] have cement slurry designed to allow cementing back to surface. Where this is not possible, the top of cement should[1] be to a point high enough within the surface casing to establish zonal isolation. The cement slurry should[Error! Bookmark not defined.] be designed for the anticipated wellbore conditions.

3.4. Production Casing and Liners

Cementing of production casing or liners should[Error! Bookmark not defined.] include a volume of cement designed to: 1) allow circulation of cement to the surface, or 2) allow circulation of cement to a point within the next casing string, or 3) establish zonal isolation of permeable zones. The cement slurry or combination of slurries and other fluids shall[1] be designed for hydrostatic weight control and strength requirements.

3.5. Cement Plugs

Cement plugs should[1] be designed with placement techniques to minimize the chance for contamination, since a diluted, non-uniform, or any other type of contaminated plug may not set properly. Small cement plug volumes are not recommended as they are more susceptible to contamination. Cement plugs of any size should[1] be designed with slurry properties and placement techniques to provide isolation under the specific wellbore conditions in which they are placed.

3.6. Remedial Cementing

Remedial cement jobs required to achieve zonal isolation of the gas storage zone should[1] be designed and placed for specific wellbore conditions. The remedial cement design should[Error! Bookmark not defined.] achieve isolation of the storage zone from all other sources of porosity and permeability.

4. Cement Slurry Design and Controls

A successful cement job requires a design that accounts for many factors including: 1) historical lessons of what has and has not worked in the past, 2) formation type, permeability, pressure and temperature, 3) prevention of contamination by formation fluids, 4) optimal compressive strength and 5) various additives to control fluid rheology (which affects displacement efficiency) and thickening times. All of this information should[Error! Bookmark not defined.] be reviewed when designing a cement slurry.

4.1. Equivalent Circulating Density

API Recommended Practice 1171 states that the equivalent circulating density of the cement pumping operation shall[8] be designed such that the fracture gradient of the storage zone is not exceeded and such that lost circulation potential of any exposed zone is minimized. This may require alternative placement methods and/or alternative cement blends. Note that cement density shall also be designed to prevent entry of any formation fluids during the cementing process, including the cement thickening process, for production casing and/or liners.

4.2. Excess Slurry Volume

When the cement program calls for circulating cement to surface, excess slurry volume to account for wellbore irregularities and/or losses to the formation may be required. If available, an open-hole caliper log is very useful for determining casing-borehole annular volumes. Past practices, including cement densities used, excess volumes used, and cement top verification by logging should be reviewed and incorporated into the cement design.

4.3. Laboratory Testing

Cement slurry designs and requirements for thickening time and compressive strength may[1] be verified with laboratory testing, considering the properties of the mix water and other cement additives to be used under the specific wellbore conditions.

4.4. Mix Water

Sources of mix water may[1] be tested for PH and temperature prior to cement mixing to ensure adequacy. Mix water needs to come from a reliable, consistent source with sufficient deliverability to meet the planned cement pumping schedule. Mix water needs to be within the specifications used for the laboratory testing. A geochemical analysis may be conducted on any water source used during cementing where such properties are unknown or questionable.

Cementing Standard

4.5. Slurry Samples

Slurry surface samples should[1] be obtained after mixing and prior to pumping down hole and held for further analysis. If multiple slurries are to be used, samples should be taken from each slurry type. If possible, multiple samples may be taken throughout the cement mixing process. Cement density may be measured throughout the mixing process as an additional quality control on proper cement mixing.

4.6. Wait on Cement Time

Rig operations following a cement job should[1] allow for sufficient cement cure time to develop target compressive strengths prior to resuming subsequent well activities. Required cure time should[9] be provided by the cementing company and/or laboratory results.

5. Cement Pumping Design

Isolating the gas storage reservoir from communication with other porous and permeable formations requires the proper placement of the cement slurry so as to provide good cement bonding with both the casing and the formation.

5.1. Fluid Conditioning

Prior to cementing a casing string, fluid in the wellbore should[1] be conditioned to improve fluid mobility, which will improve displacement by the cement slurry. Such displacement is needed for good cement bonding with the casing and the formation. Note: API Recommended Practice 1171 references API 65-2 for guidance on conditioning of fluid within the wellbore.

5.2. Spacers and Pre-flushes

Spacers and pre-flushes should[1] be used to help remove any mud cake that may exist and also isolate potential cement contamination due to dissimilar fluids. Mechanical means, such as scratchers, may also be used to remove mud cake. Note: API Recommended Practice 1171 states that spacers and pre-flushes are often weighted to prevent fluid entry during the pre-cementing hole conditioning process.

5.3. Casing Centralization

Casing centralization should[1] be used to prevent cement channeling, especially in and near zones where good cement bonding is critical, which may include areas with high wellbore inclination angles and/or highly permeable geologic formations – these factors should[1] also be considered. Note: API Recommended Practice 1171 states that casing centralization aids in the removal of drilling fluids behind the pipe during the cement slurry pumping process and thereby improves the uniform flow of cement up the annulus. API 10D-2, API 10TR4, and cementing service company technical experts can provide additional guidance and recommendations for proper casing centralization.

5.4. External Casing Packers

External casing packers and/or other mechanical barriers may[1] be used in zones where isolation through cementing practices alone has a lower than acceptable probability of success.

5.5. Guide Shoe and Float Collar

A guide shoe should[1] be used on the first joint of the production casing to avoid issues such as wellbore ledges, sidewall caving and damage to the bottom of the casing while running in the well. A float may be added to the shoe to provide an additional barrier to backflow of the cement. A float collar should[1] be used one or more joints above the guide (or float) shoe to prevent cement from back flowing and to prevent contaminated cement from reaching the shoe. The float valve(s) should[1] be checked prior to full pressure release at the surface. Competent, uncontaminated cement shall[1] be placed around the casing shoe and around the circumference of the casing.

5.6. Wiper Plugs

A wiper plug should[1] be used during the cementing of the production string to help control displacement volumes and reduce the potential for cement contamination. Casing strings normally use a two-plug wiper system: one plug is run before the cement is pumped and the second plug is run after the cement is pumped. Proper plug inspection and loading is essential as the pre-cement plug is designed to rupture to allow the cement to pass through, and the post cement plug is not designed to rupture. Liners often use only one plug, depending on liner design.

5.7. Pipe Movement

Pipe movement (when feasible, including rotation and/or reciprocation) during hole conditioning and pumping of cement should[1] be used to eliminate or reduce the possibility of cement channeling. The movement of pipe should[1] stop once the cement is in place and while waiting on development of the cement’s compressive strength. If scratchers are used, pipe movement can assist in mud cake removal during pipe movement.

5.8. Pumping and Mixing Equipment

Pumping and mixing equipment should[1] be rated appropriately for anticipated pressures and rates required for the job. Such equipment may be tested on site to the appropriate pressure prior to job start up. Cementing equipment should[1] be capable of controlling slurry density and providing a continuous pumping operation at designed rates and pressures. In order to address possible failure of pumping equipment, back-up equipment should[1] be available.

6. Cement Evaluation and Location

Evaluation of the location and bonding quality of casing cement is essential in determining if a competent seal exists to confine storage gas below the cap rock and prevent migration out of zone.

The location and quality of such bond or seal shall[1] be evaluated to ensure adequate formation and pipe bonding has been achieved to prevent migration of gas and fluids between zones. Cement bonding across the caprock of the storage zone is important.

Evaluation methods include: 1) a temperature log run in the first 12 to 24 hours after cementing to determine the location of the cement top and 2) both conventional bond logs and radial cement bond logs to determine that adequate bonding exists across the cap rock and help identify any cement channeling that can impair zonal isolation. The evaluation method used should[1] be run after the cement cure time required for the cement to reach sufficient compressive strength for accurate log measurement. The cement placement and bond quality evaluation shall[1] be conducted with a method that can demonstrate the sealing potential of the cement.

The well's annuli after cementing should[1] be observed to ensure that no annular flow exists.

API Recommended Practice 1171 cites API 10TR1 which provides principles and practices regarding the evaluation of primary cementation of casing strings in oil and gas wells and suggests a mechanical integrity test of each casing string should[1] be completed prior to drilling out or perforating.

7. Recordkeeping

As per API 1171, Section 6.11, records of well completion (as-built), well construction and well work activities shall[1] be maintained for the life of the facility. These records shall[1] include, as applicable and available, the items listed below for cementing practices:

- Cement blends, additives used, and volumes pumped
- Volumes of cement circulated to surface
- pH of mix water and water temperature
- Pump and displacement rates and displacement times
- Theoretical and actual displacement volumes
- Preflush type and volume pumped
- Type of float(s) and centralization equipment used and its location in the casing string
- Details of any remedial cementing work performed, including cementing reports, type of equipment used and its location in the well, rig and/or recompletion reports
- Cement service company's field report and job log

- Logged cement placement and any evaluation of the quality of the cement seal
- Received equipment and material specifications
- Changes in well construction from original well design
- Rig and service company field tickets and job logs
- Daily rig and servicing reports

It is also recommended that the cement density and yield be documented in the cementing records.

END of Requirements

Definitions

Refer to definitions in API 1171 and CalGEMs regulations.

Implementation Responsibilities

GSAM

Governing Document

GSAM Standard 1

Compliance Requirement / Regulatory Commitment

Regulatory codes listed in GSAM Standard 1, Section 3.

Reference Documents

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

GSAM Standard E1, Design and Specifications for Construction of Natural Gas Storage Wells.

GSAM Standard E1A, Wellhead Equipment Design

GSAM Standard E1B, Tubular Design

Cementing Standard

GSAM Standard E1D, Well Abandonment.

API 10A Specification for Cements and Materials for Well Cementing, Twenty-Fifth Edition, Includes Addendum (2019)

ASTM C150/C150M Standard Specification for Portland Cement 2020 Edition, April 1, 2020

API 65-2 Isolating Potential Flow Zones During Well Construction, Second Edition/December 2010

API 10D-2, Recommended Practice for Centralizer Placement and Stop-collar Testing, 1st Edition, August 2004

API 10TR1 Cement Sheath Evaluation, 2nd Edition, September 2008

API 10TR4 Selection of Centralizers for Primary Cementing Operations, 1st Edition, May 2008

Appendices

n/a

Attachments

n/a

Document Recission

This replaces Appendix E1C of the Underground Storage Risk and Integrity Management Rev 5.

Document Approver

Larry Kennedy, Strategic Planning Chief, GSAM

Document Owner

Lucy Redmond, Director, GSAM.

Document Contact

Larry Kennedy, Strategic Planning Chief, GSAM

Revision Notes

Where?	What Changed?

Cementing Standard

RIMP Appendix E1C to this standalone standard	Minor language changes were made for clarity. No content changes were made

Well Abandonment Standard

Summary

Purpose: This standard provides requirements, specifications and procedures for the design and construction of natural gas storage wells.

What: This is to document the design and specifications for construction of natural gas storage wells.

Why: Standard designs and specifications for storage well abandonment ensure a consistent approach is employed, that has been developed by SMEs as the optimum technical and compliance solution for PG&E.

When: This applies to new wells and reworks.

Target Audience

Gas Storage Asset Management

Safety:

n/a

Well Abandonment Standard

TABLE OF CONTENTS

1. Scope

1.1. Purpose

The purpose of the Well Abandonment Standard (WAS) is to ensure that well plugging and abandonment performed by PG&E meets internal and regulatory requirements and does not pose an environmental or safety risk.

The WAS adheres to the following:

- PHMSA IFR – Pipeline Safety: Safety of Underground Natural Gas Storage Facilities
- State, Federal and other local jurisdictions regulations

1.2. Application

The well abandonment standard is to be applied for:

- Consideration in the design of new wells

Well Abandonment Standard

- Consideration of wells scheduled for remediation and reconditioning
- Wells scheduled for permanent abandonment

1.3. Contents

The well abandonment standard contains general guidance required to perform well abandonments. Operating procedures produced separately to the well abandonment standard detail the steps required to complete a well abandonment.

1.4. Deviations from Design Standard

Well abandonments that do not meet the minimum requirements of the well abandonment standard require approval from a PG&E Officer.

Provisions containing the word ''should'', "may" or other non-mandatory language will be considered mandatory where denoted by a footnote. Depending on the degree of deviation, a risk assessment may be required as well as approvals from state, federal and other local jurisdictions.

Abandonment designs that exceed the requirements of this standard are acceptable; however, the abandonment engineer should evaluate the additional costs and benefits associated with such a design.

2. General

A well has the potential to become a conduit for fluid flow between penetrated hydrocarbon bearing zones, freshwater aquifers and the surface. Properly plugging a well prevents such fluid migration, providing long-term isolation. The well abandonment design shall[1] provide for long term isolation of the storage zone in order to prevent fluid flow between the storage zone and any other penetrated zone and the surface.

At any depth where an isolation barrier is required, multiple casing strings may be present. The condition of casing and cement across these zones shall be determined in order for complete isolation to be achieved. This may mean, but is not limited to, analysis of cement bond logging, volumetric calculations and/or remedial cement operations.

API Bulletin E3 should be referred to for best practices and procedures for the detailed design and execution of the abandonment.

For compliance with State regulations, the California State Geologic Energy Management Division (CalGEM) regulations found in California Code of Regulations, Title 14, Div. 2, Chapter 4-1, Article 3 should be consulted.

[1] As per API RP 1171

Well Abandonment Standard

3. Storage Zone Isolation

Effective isolation will be achieved by the equivalence of reinstating the cap rock. This includes isolation both inside and outside each casing string as required to prevent migration of fluids.

3.1. Plugs

Cement and/or mechanical plugs shall[1] be used to isolate the storage zones from fluid migration. For any design, the long-term viability should[1] be considered such that the required isolation is maintained. Hydrostatic pressure alone, shall[1] not be acceptable.

The quality of the cement used should meet or exceed requirements specified in API 10A and ASTM C150/C150M and should not use volume-extending additives.

Any cement plugs used for isolation should be of adequate length necessary to achieve long term isolation. Cement viability is considered in the U.S. Bureau of Safety and Environmental Enforcement (BSEE) Report RLS0116 which is referenced in API 1171.

To ensure the integrity of a cement plug, before the plug is placed, the well should[1] be static and remain so as the plug sets.

3.2. Ground Water Protection

The depth determined to be source of groundwater (Base of Fresh Water – BFW) shall also be protected to prevent contamination. The condition of the well's casing and cement across such zone shall be determined. The abandonment design shall include provisions to prevent communication between BFW and any other zone during and after the well is plugged. Remedial cement work may be required to isolate fresh water formations behind uncemented casing.

3.3. Hydrocarbon Bearing Zones

Hydrocarbon bearing zones (in addition to the storage zone) which were penetrated by any well to be abandoned shall be identified and the well's casing and cement across such zones shall be determined. The abandonment design shall include provisions to prevent communication between any of such zones during and after the well is plugged. Remedial cement work may be required to these zones behind uncemented casing.

3.4. Limited Wellbore Access

There may be several incidences where placement of plugs across the storage zone or other critical zones is limited due to wellbore conditions. The condition of the well to be abandoned should[1] be assessed prior to well abandonment design. Special provisions may be needed to establish conditions for long term plug sealing reliability.

3.5. Verification of Casing-Borehole Seals

The location and presence of any cement plug shall[1] be verified once sufficient compressive strength has been reached, and any deviation which will endanger the efficacy of the isolation shall be rectified. The casing-borehole cement sealing the storage zone shall[1] be verified to achieve annular isolation and prevent communication.

4. Abandoned Well Maintenance

A surface plug and cap shall[1] be installed on any abandoned well. The cap shall[1] be marked with a form of identification such as the API number of the well and should be at least as thick as the thickest outer casing (be it conductor or surface casing).

Should a leak become evident, the implication may be that sufficient isolation has not been maintained and the appropriate repair shall[1] be facilitated.

5. Recordkeeping

As per API 1171 Section 6.11, records of well completion (as-built), well construction and well work activities shall[1] be maintained for the life of the facility. These records shall[1] include, as applicable and available, the items listed below for well abandonment:

- Equipment removed from the well
- Cementing reports
- Plugging records filed with local regulatory authorities
- Rig and service company field tickets and job logs

END of Requirements

Definitions

Refer to definitions in API 1171 and CalGEMs regulations.

Implementation Responsibilities

GSAM

Governing Document

GSAM Standard 1

Well Abandonment Standard

Compliance Requirement / Regulatory Commitment

Regulatory codes listed in GSAM Standard 1, Section 3.

Reference Documents

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

GSAM Standard E1, Design and Specifications for Construction of Natural Gas Storage Wells

GSAM Standard E1A, Wellhead Equipment Design

GSAM Standard E1B, Tubular Design

GSAM Standard E1C, Cementing

U.S. Bureau of Safety and Environmental Enforcement (BSEE) Report RLS0116 regarding plugged wells.

API Spec 10A Specification for Cements and Materials for Well Cementing, Twenty-Fifth Edition, Includes Addendum (2019)

ASTM C150/C150M-17 - Standard Specification for Portland Cement

Environmental Guidance Document: Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations. API Bulletin E3 1st Edition 1993 (Reaffirmed 2000)

California Code of Regulations, Title 14, Div. 2, Chapter 4-1, Article 3, 2017 (CalGEMs regs applicable to storage)

Appendices

n/a

Attachments

n/a

Document Recission

This replaces Appendix E1D of the Underground Storage Risk and Integrity Management Rev 5

Document Approver

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Document Contact

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Revision Notes

Where?	What Changed?
Converted RIMP Appendix E1D to this standalone standard	Minor language changes were made for clarity. No content changes were made

Fluids Management

SUMMARY

This standard is to provide guidance for the design and management of fluids during well workover operations, along with specifications and sampling/analysis requirements for completion fluids and reservoir fluids. This document is intended to supplement existing guidance in the Risk and Integrity Management Plan that is relevant to fluids analysis used for operations and well work, fluids analysis used prior to produced fluids disposal, and management of fluids during operations and well work.

TARGET AUDIENCE

This standard applies to all engineering, technical and operations personnel engaged in well engineering, design, and rework execution.

SAFETY

All fluids and fluid additives used on PG&E reworks shall have Safety Data Sheets and shall be made available upon request.

A Hazardous Materials Business Plan (HMBP) must be completed and submitted when hazardous materials are on site in a quantity, during the reporting year, above the thresholds laid out in the State’s Health and Safety Code § 25505.

Cleaning of tanks may require confined space entry, which requires following the confined space entry procedure.

Eyewash station shall be on-site.

No fluids are allowed on the ground. All leaks shall be repaired immediately, and all incidents, near-miss events, hazardous material and hazardous waste releases shall be reported immediately to the PG&E on-site Representative. The detailed work plan is to address any site-specific environmental concerns and mitigation measures to be taken (PGE RIMP Appendix AE, Underground Storage Facility Drilling/Rework Safety and Environmental Plan).

Proper PPE must be used, including but not limited to:

- Safety glasses
- Mask for handling fluid additives
- Gloves for handling hazardous chemicals

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SUBSECTION TITLE PAGE

1. Environmental

1.1. Personal shall consult with Environment Field Specialists (EFS) on the handling, collection, storage, transportation, and disposal of fluids as described in this standard. Consultation should occur prior to any operations beginning.

2. Fluids Management

2.1. Fluid Types

2.1.1. Drilling Muds

Fluids used during the drilling of wells. These can be water or non-aqueous based fluids such as diesel or synthetic mineral oil. Typically, fresh water-based muds include bentonite (clay) for viscosity and barite (weighting agent) as required to provide the density required for well control purposes.

2.1.2. Brines

Brines are fluids used for many activities during rework operations, either alone or in combination with other additives like polymers. Currently, NaCl brine is used for PG&E rework operations.

2.1.3. Polymer Fluids

Polymers are typically added to brines and used for activities that require additional viscosity or fluid loss properties. They are typically composed of NaCl brine with HEC (or XC) polymer to maintain the required viscosity properties.

2.1.4. Pills

Pills are a relatively small volume of drilling fluid used to accomplish a specific task such as increasing lifting capacity of fluids to assist with circulating out debris or fill, assist with wellbore stability, and assist with reducing lost circulation. This may be accomplished through high viscosity, increased density, or inclusion of lost circulation materials.

2.1.5. Gravel Packing Fluid

Fluids used during the placement of gravel during gravel pack placement operations. Typically, this will be clean brine with sand (proppant) added during the gravel packing operations.

2.1.6. Packer Fluids

Packer fluids refers to the fluid that is left within the annular space between the tubing and production casing above the production packer. It is typically a brine with corrosion inhibitor added to minimize corrosion of the wellbore tubulars. Packer fluid is generally designed to be “kill weight”, i.e., to provide hydrostatic overbalance to the wellbore pressure below the production packer. Although not usually in contact with the reservoir, it should be non-damaging to the reservoir in the event of inadvertent contact. The fluid normally fills the annular space to surface so as to minimize corrosion in the annular space. Packer fluids must be ‘solids free’ to prevent solids settling which can result in stuck tubing or packer.

2.1.7. Kill Fluids

Kills fluids are used to regain hydrostatic pressure control. Kill fluids generally consist of polymer fluid or brine during normal rework operations but may consist of drilling mud or other specialty fluids during well control situations.

2.1.8. Abandonment Muds

Fluid that will be left in the well after the well has been abandoned. Typically, water-based drilling mud with clay (bentonite) and weighting agent (barite) as necessary to provide the density needed for well control and the rheological properties to keep the weighting agent in suspension. CalGEM stipulates the abandonment mud properties on the permit granting the abandonment work. The CalGEM specification often has a minimum density of 72 lbs./cu ft. (9.6+/- ppg) and a minimum gel shear strength of 25 lbs./100 sq. ft, but this can vary per the work permit. The intention of this requirement is to prevent the movement of other fluids into the wellbore.

2.1.9. Cementing Operations - Mix Water, Pre-Flushes and Spacers

Through the process of cementing in the wellbore, there is opportunity for fluids associated with this process to be left in the well or to require fluid disposal. This can include mix water where free water is present in the slurry, as well as pre-flushes ahead of the slurry, or spacers behind the slurry. The fluid will remain in the annulus, on the outside of the casing, in instances where cement does not return to surface, or in the event of a cement job being over displaced. Additionally, the fluid in the well must be conditioned sufficiently to ensure proper cement placement techniques.

2.1.10. Foam

Foam may be used in operations such as coiled tubing (CT) work. This type of fluid is highly specific to the job and as such, beyond the scope of this document.

2.2. Fluid Properties

2.2.1. Density

Wellbore fluids serve as the primary barrier to prevent loss of well control. The workover fluid must be designed at the appropriate kill weight with consideration of anticipated storage reservoir pressures prior to, and, during well remediation activities. Additionally, the fluid in the well must be conditioned sufficiently to ensure proper well control at all times.

2.2.2. Compatibility

Formation damage can reduce reservoir permeability due to the introduction of solids or liquids into the reservoir formation. This can be due to plugging either from solids invasion or incompatibility with the formation or reservoir fluids.

2.2.3. Rheological Properties

Depending on the operation, fluids pumped may need to have increased viscosity to allow for circulating solids (sands or wellbore debris) to surface. Viscosity is also necessary to minimize loss of fluids to the formation. Excessive fluid loss to formation can lead to increased formation damage, higher costs, and loss of well control if not properly managed.

2.2.4. Breakdown Period

Polymers lose their viscosity or breakdown through a combination of time, temperature, and chemical reactions. This needs to be taken into account to prevent issues occurring during production or injection of the well and during the bring-in procedure.

2.3. Fluid Design

2.3.1. Fluid Properties

Specify the required fluid properties in the rework program to ensure that the planned operations can be safely and efficiently executed, and the storage reservoir is not contaminated by any foreign influence. The hydrostatic overbalance pressure requirements contained in the PG&E Well Control Standard shall be complied with. In addition, the reduction of brine density with increasing temperature must be considered.

Specified properties should include:

- Mud weight (ppg) required to control the well with adequate overbalance
- Plastic viscosity (cps and/or sec/quart)
- Yield point (lbs./100 sf)

- Gel Strength
- Rheological Properties (300/600 RPM) to enable carrying capability for sand / debris cleanout
- API Filtrate / Water Loss (cc/30 min)
- pH
- Acceptable % solids
- Filter size (if applicable)

The mud/fluids contractor shall prepare a mud or fluids program prior to each rework. An example mud program is shown in Figure 1.

NaCl/HEC MUD PROGRAM

VISCOUS PILL, SCRAPER AND LOGGING RUNS INSIDE 8 5/8" CASING:

9%NaCl/HEC

Mix fluid as follows: (assuming 80 bbl pit capacity) with premixed NaCl /HEC fluid from GEO's woodland facility. Minimal inventory will be on location for any new volume additions.

Kill well and spot fluid in the open hole to the production liner with some excess. Next, the rig will perform a scraper and mill runs after pulling liner. A bridge plug will be installed.

Keep the hole clean during scraper runs by maintaining a 42-45 sec. /qt. viscosity with HEC treatments as directed by the mud engineer.

After logging the well, pressure test 8 5/8" Casing. Run in hole and retrieve downhole and retrievable bridge plugs and pull out of hole. Trip in open-ended to TD and circulate.

Set packer and laydown work string. Run in hole with 4 ½" completion string and circulate out brine with annular packer fluid.

Projected formation pressures will be adequately controlled with sodium chloride up to 8.8-9.0 ppg. McDonald Island's anticipated filed pressures range from 1500-2000 psi.

Mud Weight (ppg)	8.8-9.0	**3/6 RPM**	2-4/3-6
Plastic Viscosity (cps)	14-20	**API Filtrate (cc/30min)**	20-30
Yield Point (lbs./100 ft²)	18-26	**pH**	8.0-8.5
10 sec/10 min Gels	3-5/4-8	**% Solids**	1-2

CIRCULATE 9.1PPG (14% NaCl) PACKER FLUID TO LAND TUBING HANGER AND ANCHOR INSIDE OF SC PACKER

With Anchor 10' above SC production packer roll pumps to circulate fluid while slacking off tubing. Once seals engage packer test backside to 500psi to ensure engagement. Once tubing is in place pressure test control line to 3000psi and monitor pressure. Slack off tubing string so anchor seal assembly is 10'-15' above SC production packer.

CIRCULATE 9.1PPG PACKER FLUID CONTAINING CORROSION INHIBITOR AND BIOCIDE. Corrosion Inhibitor and Biocide to be mixed in concentrations of 10 gal. / 100bbls each.

Figure 1: Sample Mud Program

2.3.2. Fluid Performance

Assess estimated hydrostatic and frictional pressures to ensure loss circulation is minimized during the planned operations.

2.3.3. Fluid Compatibility

Assess fluids for reservoir compatibility with the reservoir clays, reservoir fluids, and tubular goods.

Additives require review by PG&E's Environmental, Corrosion Engineering and Reservoir Engineering departments prior to use.

2.4. Responsibilities

2.4.1. Project Reservoir Engineer

- Fluid Design and Incorporation in the rework program.
- Review plan for fluids in the well rework program review with execution team.

2.4.2. Wellsite Manager

- Confirm sufficient volume of fluid is on site to support operations.
- Work with Mud Engineer to ensure fluids are fit for purpose.
- The WSM is responsible for checking pump procedures, volumes, and strokes during fluid changeover operations and/or spotting pills to ensure fluid consistency is achieved.

- Review the anticipated presence of fluids in the wellbore with contractors and conduct a rig pre job safety inspection with PG&E safety representative prior to accepting rig on books per “Underground Storage Risk and Integrity Management Plan”, and before fluid is introduced. Document inspections as described in Appendix AH, section 2.5 of the “Underground Storage Risk and Integrity Management Plan”.

2.4.3. Mud Engineer

- Testing of fluids once/day or as needed, to ensure drilling fluid requirements specified in program are being maintained.
- Document composition of all fluids used during rework operations.
- Monitor returns during fluid changeover operations and/or spotting pills.
- Maintain the minimum inventory of fluids and additives on location required for new volume adds

2.4.4. Rig Crew

- Check Mud Weight and Funnel Viscosity as required to ensure consistency when circulating.
- Add chemicals or additives to maintain prescribed fluid properties per instructions from WSM and Mud Engineer.

2.5. Fluid Transportation

Fluids are typically pre-mixed at the mud company’s yard and transported to the wellsite by vacuum trucks. To prevent contamination of workover fluids, vac truck contractors should document that their trucks have been thoroughly cleaned or lined to avoid any contamination of fluids during the transportation of work over fluids. Consideration should be given to spot check vac trucks to determine if trucks are adequately cleaned.

Fluids should be tested before and after shipping to verify fluid properties. Tests for mud weight and viscosity should be tested and documented as a minimum.

Manifests for all incoming and outgoing fluids are required.

2.6. Fluid Storage

2.6.1. Tanks

Fluids in use are stored onsite in storage tanks or mud pits. Drilling fluid volumes and required additives in sufficient quantities to ensure well control is maintained must be kept at the well site for immediate use. It is required that a minimum of 150% above the volume in the well be maintained onsite in rig pits or storage tanks.

Drill and cement fluid tanks must be covered to prevent bird entrapment. In addition, all tanks and pits should be covered to prevent rain contamination when appropriate. Containers used for additives which may be oily, flammable, or hazardous, such as caustics or acids, must also be equipped with covers.

Fluids for disposal may need to be kept for around one to two weeks while testing to confirm the appropriate disposal method is ongoing. If in an open top tank, nets are recommended to prevent wildlife or debris entering the fluid.

Equipment containing fluid shall be placed within secondary containment that is compliant with PG&E environmental policies. Fluids in containment must be managed as per the subject SPCC, Federal and State regulations

Hazardous and non-hazardous materials shall not be mixed.

2.6.2. Cleanliness

Unlined tanks, pipelines, tubulars, suction lines, discharge lines and manifolds must be thoroughly cleaned prior to being used with clean fluids. These items can contain rust and debris which can contaminate the fluids.

2.6.3. Testing

Calibrated test equipment should be used to verify the fluid properties on a periodic basis to be included in the daily mud report. No fluids should be pumped downhole without testing to verify the properties of the fluids.

2.6.4. Labeling

All fluid tanks must be correctly labeled. If a tank contains flammable, corrosive, or hazardous fluids, additional labeling is required per PG&E Fluid Labelling Guidelines. The current practice involves use of magnetic labels that communicate what the fluid type is and if it is clean or dirty. Hazardous fluids have additional labelling requirements including that the fluid is hazardous and status of testing.

2.6.5. Solids Control

The workover rig must be equipped with equipment capable of removing solids from the wellbore fluids to minimize the amount of dilution and maintain the planned fluid properties. Solids control equipment is likely to include the following:

- Shaker Screens
- Desilter, Desander, and/or Hydrocyclones on Mud Cleaner
- Filters

2.6.6. Conditioning of Stored Fluids

Fluids used for well work often have a high content of solids in the form of HEC polymer. These materials will settle when static and eventually concentrate in the lower levels of the storage vessel.

In order to maintain the usability and fluid properties, a schedule should be prepared to circulate and condition the fluid at regular intervals (three to four-day). Storage tanks should be thoroughly cleaned or lined prior to use and fitted with the proper mixing and circulating equipment if they are to be used for fluid storage. Using vacuum trucks to pull fluid from a tank, and then push it back into the tank is ineffective and costly and therefore discouraged.

Two methods are suggested for fluid storage:

1. Use tanks with bottom discharge manifolds and an upper circulating fill line. This should be at mid tank level and extend forward internally to about the tank midpoint lengthwise (most but not all of the PG&E tanks are configured as such). Then use a stand-alone centrifugal pump to circulate a minimum of two tank volumes at 3-5 bbls/minute every three to four days.
2. Use tanks, as above, and configure the rig centrifugal pump to each tank, utilizing the rig pump/crew to roll and condition tank fluids at convenient intervals. A fabricated suction manifold would make it easier to tie all the tanks together and minimize hose requirements, facilitating rig capability to pump into and out of each tank as necessary. Arrangements as above would be needed to condition fluid stored remote to the rig.

2.7. Fluid Property Testing

Testing of the fluids is very important to ensure the properties are suitable for the fluids' planned function. A fluids report shall be prepared by the mud engineer on a daily basis during reworks, a sample of which is shown in Figure 2. Testing shall be conducted per API 13B for the following properties, at a minimum. Additional property testing will be at the discretion of the mud engineer or WSM or as specified in the rework program:

2.7.1. Temperature

Flowline temperature (F) should be documented on the daily report as fluid properties can vary based on temperature.

2.7.2. Density

Fluid weight is checked to ensure the fluid is maintaining the required density to ensure the primary well control barrier is being maintained. Fluid weight should be checked frequently to detect conditions such as entrained gas which may indicate the wellbore is becoming underbalanced.

2.7.3. Funnel Viscosity

Funnel viscosity (FV), though not a true viscosity measurement, is a simple check to determine how thick the mud sample is, which can be easily performed by the rig crew. Changes in the funnel viscosity can indicate the fluid properties are changing.

2.7.4. Plastic Viscosity

Plastic Viscosity (PV) is a parameter analyzed to determine the rheological properties of the fluid. A high PV indicates high solids content. A high PV is undesirable as it results in high frictional pressures when circulating.

2.7.5. Yield Point

Yield Point (YP) is another rheological parameter which can be analyzed to determine the hole cleaning capabilities of the fluid. A high YP results in increased carrying capacity of the fluids; but also results in increased circulating frictional pressures in the annulus. This results in higher surge and swab pressures and an increased risk of lost circulation.

2.7.6. Gel Strength

Gel strength is another rheological parameter that measures the shear stress necessary to initiate flow of a fluid that has been static for a long time. A high gel strength can indicate that initiating circulation may require high pressures. Gel strength also indicates an ability of a fluid to suspend solids (such as mud additives or debris).

2.7.7. pH and Alkalinity

Maintaining the correct pH level is important to enable additives to chemically react and provide the desired properties. Failure to maintain the correct pH can result in using more drilling additives being needed to achieve the right viscosity.

2.7.8. Calcium

Measuring calcium will help determine if contamination has, or is, occurring.

2.7.9. Filtrate

Filtrate measures properties of the fluid to give a qualitative indication of its likelihood to leak off into the formation.

2.7.10. Chlorides

Measuring chlorides will help determine if contamination has, or is, occurring. This can result in increasing or decreasing chlorides.

2.7.11. Solids Content

Fluids Management

The solids content is an indication of how “dirty” a fluid is. A fluid with a solids content higher than when it was originally mixed, indicates clays and rock particles are suspended in the fluid. If these solids are deposited in the reservoir matrix, formation damage may occur.

REPORT DEPTH	5,235'	5,235'
FLOWLINE TEMP	99 °F	DEPTH
MUD PROPERTIES		5,235'
WEIGHT (ppg/ppcuft)	°F	8.8 | 66.0
MUD GRADIENT (psi/ft.)		0.45864
FUNNEL VIS (sec./qt.)	99 °F	41 99°F
PLASTIC VISCOSITY (cps)		13
YIELD POINT (lb./100 sq. ft.)		16
GEL STRENGTH (lb/100 sq. ft.)	10 SEC.	1
	10 MIN.	1
	30 MIN.	
pH		8.6
FILTRATE (ml/30 min.	°F	20
CAKE THICKNESS (32nd in.)		
HTHP		
SOLIDS CONTENT (corr. % by Vol.)		
OIL CONTENT (% by Vol.)		
WATER CONTENT (corr. % by Vol.)		100.00
% Sand Content		
CHLORIDES (ppm)		58,000
pf		0.10
mf		0.45
Total Hardness/Calcium (ppm)		160
LSYP		
MBT (lbs/bbl Bentonite Equivalent)		

Figure 2: Sample Fluids Report

2.8. Management of Change (MOC)

Changing fluid type or properties from the approved program may require an MOC. See Underground Storage Risk and Integrity Management Plan Appendix AC for more details.

2.9. Fluid Disposal

Any fluids used or generated during rework operations – including completion fluids, etc. – must be tested prior to disposal at a third-party facility. This applies to the first shipment only or any time changes could alter the existing waste determination. This may require storage of waste fluids while the testing is being performed. Refer to PG&E Fluids Disposal Document and section 2.6 of this document for more information.

Manifests of disposal fluids must be kept in WSM office. A secondary copy can be kept in the well file.

Copies must also be provided to the Project EFS (Environmental Field Specialist) at the conclusion of the project.

2.10. Record Keeping

The daily operations reports and daily mud reports shall be kept in the Well File per corporate standard GOV-7101S Enterprise Records and Information Management Standard. These shall document composition and volumes of any fluids used, the type and amount of fluid in the annulus of a tubing packer completion (packer fluid) and any fluid losses to the formation.

3. Completion Fluid Sampling, Quality, and Analysis

3.1. Purpose

Per the *Underground Storage Risk & Integrity Management Plan Publication Date: March 29, 2019, Revision 5*, fluids used to workover the well, particularly those that will be left in annular spaces (i.e., packer fluid), must be analyzed to ensure that there are no incompatibilities between them and the reservoir and to ensure corrosion potential is low. In addition, sampling and analysis is required to comply with CalGEM and PHMSA regulations.

Completion fluids consist of brines, polymer fluids and pills, gravel packing fluids, and packer fluids.

3.2. Sampling

Sampling and testing shall be tracked with *Form 62-1174, “Chain of Custody Record,”* and *Form TD-4186P-100-F01, “Liquid Sampling Log.”*

3.2.1. Brine and Polymer Fluids

Brine and polymer fluid properties are sampled and tested daily as described in Section 1.7. Samples shall be taken in order to test for Microbial Induced Corrosion (MIC), heavy metals, and Chlorides. Samples should be initially taken monthly, and adjusted accordingly, throughout the workover season. Corrosion coupons in the drill string may be used as an alternative.

3.2.2. Gravel Packing Fluid

Gravel packing fluids should be sampled for cleanliness prior to each gravel packing job.

3.2.3. Packer Fluid

Samples shall be taken in order to test for Microbial Induced Corrosion (MIC), heavy metals, and Chlorides. Samples shall be taken from every well.

3.3. Documentation

3.3.1. Fluids Composition

The Daily Report and daily mud reports shall document the composition of completion fluids.

3.4. Analysis

3.4.1. Brines and Polymer Fluids

Brines and polymer fluids will be analyzed onsite as described in Section 2.7. Fluids used during workover operations must be assessed to ensure that they are:

- Solids free
- Provide necessary inhibition to prevent clays within the reservoir from swelling
- Compatible with native brines to prevent formation of precipitates
- Minimize corrosion of tubular goods

3.4.2. Gravel Packing Fluid

No specific analysis is required.

3.4.3. Packer Fluid

Corrosion Monitoring and Evaluation (*Underground Storage Risk and Integrity Management Plan*) requires analysis of packer fluid corrosion potential. Analysis will consist of testing for Microbial Induced Corrosion (MIC), heavy metals, chlorides and pH. Packer fluid analysis is typically performed at the PG&E Applied Technology Services (ATS) lab and looks for MIC characteristics that result in higher corrosion potential including:

- Sulfate-reducing bacteria
- Acid-producing bacteria
- Anaerobic/partially anaerobic bacteria
- Aerobic bacteria

A typical lab report is shown in Figure 3.

Packer fluid must also be assessed to ensure it is compatible with the reservoir as per the requirements in 3.4.1 as it may inadvertently come in contact with the reservoir.

Fluids Management

Applied Technology Services

Pipeline Liquids MIC (Microbiologically Induced Corrosion) and Moisture Test Report

ATS Record # 412.20.18

ATS Login #	ATS200409-9926
Location	Gas Well Packer Fluids McDonald Island
Leak # / Other Client ID	Whiskey Slough-1AE Truck #1
Sample Temp on Delivery (C)	n/a
Dilution Factor	1

Sample Information

Date Sampled	4/7/2020
Date Received	4/9/2020
Inoculation	4/9/2020
Date Analyzed	4/24/2020
Inoculation Period (Days)	15

Free Water Present ? ☑ Matrix Type Liquid KF Moisture (%) n/a

MICKIT III Results

SRB - Sulfate-reducing bacteria
APB - Acid-producing bacteria
AnB - Anaerobic/partially anaerobic bacteria
AB - Aerobic bacteria

	Highest Bottle # to Turn Positive		Range of Viable Bacteria per mL of Sample
SRB	0	SRB Count	No Reaction
APB	0	SRB Count	No Reaction
AnB	0	SRB Count	No Reaction
AER	1	SRB Count	1 - 10

Figure 3: Typical Metallurgical Compatibility Test Results

3.5. Quality – Acceptable Range

3.5.1. Brines and Polymer Fluids

The acceptable range of brine and polymer fluid properties will be specified in the rework program and/or mud/fluids program.

3.5.2. Gravel Packing Fluid

Fluid must be filtered before use according to service company operating procedures.

3.5.3. Packer Fluid

There are currently no pass/fail criteria for bacterial activity in packer fluids. Test results are approved by the Integrity Management group.

The density of the packer fluid shall provide hydrostatic overbalance at all reservoir pressures anticipated during the life of the completion.

4. Reservoir Fluid Sampling, Quality, and Analysis

4.1. Purpose

Sampling of produced liquids and solids is required per the *Underground Storage Risk & Integrity Management Plan Publication Date: March 29, 2019 Revision 5* to determine the corrosion potential of produced liquids, fluid/rock compatibility, scaling tendencies and/or precipitation. Note that this requirement does not include reservoir gas. In addition, sampling and analysis is required to comply with CalGEM and PHMSA regulations.

4.2. Sampling

Liquid and solids samples will be collected from active flow lines during withdrawal season to evaluate the corrosive potential of the product stream. Liquid sample collection points are currently limited to comingled product streams; however, piping modifications are being evaluated to facilitate liquid sampling from individual flow lines.

Samples should be taken in accordance with *Utility Procedure: TD-4186P-100*.

Sampling and testing shall be tracked with a chain of custody form such as *Form 62-1174, "Chain of Custody Record,"* and *Form TD-4186P-100-F01, "Liquid Sampling Log."*

4.3. Analysis

Samples are tested for Microbial Induced Corrosion (MIC), heavy metals, chlorides and pH, including:

- Sulfate-reducing bacteria
- Acid-producing bacteria
- Anaerobic/partially anaerobic bacteria
- Aerobic bacteria

The testing procedure and criteria should be in accordance with *Utility Standard: TD-4186S.*

4.4. Quality – Acceptable Range

There are currently no pass/fail criteria for bacterial activity in reservoir fluids.

END of Standard

Fluids Management

DEFINITIONS

See Section 2.1.

IMPLEMENTATION RESPONSIBILITIES

Reservoir Engineering leadership will communicate the publication of this standard to the affected personnel and provide training to affected personnel.

GOVERNING DOCUMENT

GSAM Standard 13 Corrosion Monitoring and Evaluation

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

This standard has been written to ensure compliance with the following regulations (see Summary of Agency Requirements in the Appendices for further details):

State

1. Cal OSHA Subchapter 14. Petroleum Safety Orders--Drilling and Production

2. California Code of Regulations, Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Development, Regulation, and Conservation of Oil and Gas Resources, Subchapter 1, Onshore Well Regulations as applicable

Federal

1. Code of Federal Regulations (CFR) Chapter 49, Part 192, Subpart 192.12, Underground Natural Gas Storage Facilities

2. PHMSA's 2018 law implementing API RP 1171 as federal law

3. OSHA regulations for Construction as applicable

REFERENCE DOCUMENTS

Developmental References:

GSAM PG&E Well Control Standard

API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, First Edition, 2015

API RP 13B-1 5TH ED (E1) — Field Testing Water-based Drilling Fluids; Fifth Edition

Supplemental References:

ANSI/API RP 13M 1ST ED (R 2018) — Recommended Practice for the Measurement of Viscous Properties of Completion Fluids; First Edition; Reaffirmed, December 2018; ISO 13503-1:2003

APPENDICES

N/A

ATTACHMENTS

N/A

DOCUMENT RECISION

This is the initial version of this standard (Rev 0 once approved and issued).

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

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REVISION NOTES

Where?	What Changed?
N/A	This is a new standard

APPENDIX A - CHANGE CONTROL GUIDANCE DOCUMENTS

Document / Form	Description / Application

Mechanical Integrity of Wells

SUMMARY

This standard addresses ongoing verification and demonstration of the mechanical integrity of each well[1] used in the underground gas storage project and each well that intersects the reservoir used for gas storage, and is supported in more detail in the procedures listed in Supplemental References at the end of this standard.

The protocols for verifying and demonstrating well integrity shall not be limited to compliance with the mechanical integrity testing requirements under CCR 1726.6 and 1726.7 and include consideration of risk-based decisions for each well.

Gas storage wells may be in service for many years. Therefore, it is prudent to choose and employ a design life and to monitor and maintain the integrity over this life to manage risks within design limits and to prevent gas leakage. Methods utilized to assess and prevent future casing failures and gas releases include storage well logging (CCR 1726.6(a)(1) thru (2)), cathodic protection and monitoring, Pressure Test (Mechanical Integrity Test) (CCR 1726.6.6.1), and annular pressure monitoring (CCR 1726.7(d).

Any well that does not successfully completed shall not be used for injection or withdrawal without subsequent approval (CCR 1726.6(d)).

NOTE: A number of important reference procedures support this standard - refer to the procedures listed in the Reference Document section. These are listed here for emphasis

- GSAM Procedure B, Additional Investigations
- GSAM Procedure C, Casing Inspection Survey Frequency Decision Tree
- GSAM Standard D, Remedial Options and Decision Tree
- GSAM Procedure F, Creating and Updating Storage Wellbore Schematics
- GSAM Procedure G3, Creating and Updating Storage Wellhead Diagrams
- GSAM Procedure K7, Mechanical Integrity Test Acceptance and Frequency
- GSAM Procedure S15, Casing Inspection Logging and Data Assessments
- GSAM Procedure Z, Well Integrity Testing Regime Process – Production Casing
- GSAM Procedure 14B, Well Risk Assessment and Relative Risk Ranking

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

[1] CCR Chapter 2, Article 5, 1726.1 defines a gas storage well which includes active or idle wells used primarily to inject or withdraw gas from an underground storage project

Gas Pipeline Operation and Maintenance (GPOM

Corrosion Department (CD)

Safety:

Safety issues are addressed in each of the procedures referenced in the requirements below.

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REQUIREMENTS

1. Well Characterization and Analysis

Each active and plugged well within the buffer zone is characterized for its mechanical "as is" condition by means of a wellbore schematic (and for active wells, a wellhead diagram) utilizing the practices in GSAM Procedure F2, Creating and Updating Storage Wellbore Schematics and GSAM Procedure G3, Creating and Updating Storage Wellhead Diagrams. The schematics and diagrams are maintained in a current state and reflect the most recent well entry findings, workovers, integrity tests, and equipment changes.

Each active and plugged well within the buffer zone is evaluated for its current mechanical integrity utilizing a barrier analysis methodology to identify any deficiencies that need to be addressed. The barrier analysis incorporates tubular and wellhead design safety factors and cementing standards that meet or exceed minimum regulatory requirement.

Subsequent evaluations may be conducted using 1) the risk assessment and the information derived from the initial evaluation (GSAM Procedure C, Casing Inspection Survey Frequency Decision Tree), 2) an assessment of the need and usefulness of a well (GSAM Standard 1), and 3) relative risk (GSAM Procedure 14B). Process and results are documented as described in each section below.

Records are maintained by asset in the GSAM shared drive.

2. Quality of Testing Data

Quality reviews of testing data shall be performed to 1) review logs and other data for missing scales and well information, 2) verify that log and feature depths match wellbore schematics or other logs, and 3) make depth corrections to wellbore schematics based on review and verification.

PG&E shall report the results of its quality reviews of vendor data and document work products to vendor for correction of quality issues.

3. Storage Well Testing Regime

Storage well testing regime process shall be defined for verifying and demonstrating well integrity and shall not be limited to compliance with the mechanical integrity testing requirements under CCR 1726.6 and 1726.7 and may include consideration of risk-based decisions for each well (Procedure Z, Well Integrity Testing Regime Process).

4. Storage Well Logging

4.1. Well Logging

Wells are logged to identify potential problems and may include the following types of cased hole logs (type of log/survey identified in parenthesis).

- Reductions to casing wall thickness (MFL, Caliper, and Ultrasonic Casing Inspection Tools) (CCR 1726.6(a)(2)
- Identification of gas presence behind the casing (Gamma Ray-Neutron – GRN, Pulse Neutron) ((CCR 1726.7(b)(2)(D))
- Cement Bond Log (CBL)
- Presence of a corrosion cell (Casing Potential Profile – CPP)
- Temperature logs (CCR 1726.6(a)(1)
- Noise logs (CCR 1726.6(a)(1)
- Downhole video cameras
- E-Log-I surveys

4.2. Logs: New, Redrilled and Reworked Well Logging

In addition, for new, redrilled or reworked storage wells, the following list of logs shall be considered to be run during the operation (CCR 1726.6(b). The principle (how the log works) and the identification (purpose of the log) are presented in *Appendix 1 to this standard, Well Logging Criteria for New, Redrilled and Reworked Wells*, along with the list of logs.

4.2.1. Types of Open Hole Logs

- Caliper
- Density w/Pe (Litho-Density)
- Compensated Neutron Log (CNL)
- Spontaneous Potential (SP)
- Gamma Ray (GR)
- Resistivity Logs (Dual-Induction or Array Induction)
- Microlog (ML)

4.2.2. Types of Cased Hole Logs

- Casing Inspection Tools (i.e., Vertilog, MicroVertilog, High-Resolution Vertilog, Caliper, and Ultrasonic inspections)

- Cement Bond Log/Cement Mapping Tool with Gamma Ray and Casing Collar Locator or Segmented Bond Tool with Gamma Ray and Casing Collar Locator

- Base line TDT/PDK with Gamma Ray and Casing Collar Locator or Gamma Ray Neutron with Casing Collar Locator (CCR 1726.7(b)(2)(D)

5. Casing Inspection Tools

Casing inspection tools are beneficial to establish a baseline of casing and tubing condition and to reassess casing and tubing condition against the baseline. The following criteria summary should be utilized (refer to GSAM Procedure C, Casing Inspection Survey Frequency Decision Tree for further details):

- Run baseline logs (casing inspections (CCR 1726.6(a)(2) and/or GRN) on every well when the tubulars are removed (typically during a rework) (CCR 1726.7(b)(2)(D).

- Follow-up casing inspections are required on casing completed wells to assess the rate of change in pipe corrosion at time intervals to be determined by the condition of the pipe. (CCR 1726.6(a)(2).

- Follow-up inspections (Appendix U, Gamma Ray Neutron and RST Logging) are required to assess indications of gas behind the production casing (CCR1726.7(e)).

- Follow-up casing inspections on tubing and packer completed wells are required when tubing is pulled for other remedial work and with consideration of the time interval between the remedial work and the last casing inspection run (CCR 1726.6(a)(2).

- Noise and Temperature logs (annually) and GRN logs (periodic) will be run on tubing and packer completed wells that do not have baseline casing inspections to identify changes in gas accumulation behind pipe and review (CCR 1726.6(a)(1).

- Thru-tubing inspection logs are a new practice for PG&E and when used in conjunction with traditional casing inspection logging tools provide an opportunity to monitor for accelerated wall loss feature growth during surveillance inspections. Additionally, run ahead of baseline condition, these logs present an opportunity to flag large metal feature defects (CCR 1726.6(a)(2).

- Upon receipt and evaluation of the logs, the data, records, and subsequent actions shall be stored in the GSAM Database and well file.

- Findings requiring remediation and/or subsequent evaluation of the well should be reported to supervisor

48 hours notification to CalGEM to witness tests is required prior to running of casing inspection tools (CCR 1726.6(d)).

NOTE: Logs must be submitted to CalGEM within 30 days after being run in a well. This is accomplished by the GSAM personnel uploading files to the CalGEM web site.

For more details, please refer to GSAM Procedure S15, Casing Inspection Logging and Data Assessments.

6. Casing Potential Profile (CPP)

- Annually, Reservoir Engineering should coordinate and communication with GPOM and Corrosion to verify that wells are protected by a cathodic protection system and need for E-Log-I surveys to verify that adequate cathodic protection current is being applied to each well's production casing string (CCR 1726.3(d)(4)(D)

- Annually, Reservoir Engineering and CD will prepare a join summary on the condition of the cathodic protection system performance in providing adequate cathodic protection to protect each well's production casing. Summary should include recommendations for wells to be E-Log-I and CPP surveyed.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEM regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM integrity management engineers

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory requirements as listed in GSAM Standard 1, Section 3.

Reference Documents

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References

- GSAM Procedure B, Additional Investigations
- GSAM Procedure C, Casing Inspection Survey Frequency Decision Tree
- GSAM Standard D, Remedial Options and Decision Tree
- GSAM Procedure F, Creating and Updating Storage Wellbore Schematics
- GSAM Procedure G3, Creating and Updating Storage Wellhead Diagrams
- GSAM Procedure S15, Casing Inspection Logging and Data Assessments
- GSAM Procedure Z, Well Integrity Testing Regime Process – Production Casing

Mechanical Integrity of Wells

APPENDICES

Appendix 1 - Well Logging Criteria for New, Redrilled and Reworked Wells

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 9 of the GSAM Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 9 to this standalone standard	Minor language changes were made for clarity. No content changes were made

Appendix 1 - Well Logging Criteria for New, Redrilled and Reworked Wells

Summary

This appendix presents the variety of logs that should be considered for new, redrilled and reworked storage wells (vertical).

Target Audience

GSAM

- Integrity management engineers
- Well work project managers
- Technical work supervisors

Logs to Consider for Newly Drilled Storage Wells (Vertical)

The following table of logs should be considered for new, redrilled and reworked storage wells (vertical).

Table 1, Logs to Consider for Newly Drilled or Redrilled Storage Wells (Vertical)

Type of Log	Principle	Identification
Array Induction	A high frequency current of constant intensity is sent through a transmitter coil. The magnetic field induces currents in the formation surrounding the borehole. The currents are proportional to the conductivity of the formation.	Deep formation investigation to minimize borehole influences and measure resistivities. Fluid Contacts. Water Saturation.
Density	Medium energy gamma rays are emitted to the formation and scattered, if the formation is very dense the more scattering takes place and more gamma rays are absorbed, less dense formation the less scattering and less absorption.	Primarily used to measure bulk density. Can be related to porosity when lithology is known, gas detection, hydrocarbon density, and evaluation of shaly sands.
Compensated Neutron Logs (“CNL”)	Neutron logs measure the formation’s ability to slow the movement of neutrons through the formation. This measurement reflects the amount of hydrogen in the formation indicating the porosity of the formation. This log requires a liquid filled hole.	The compensated neutron log is recorded as apparent limestone, sandstone or dolomite porosity. It has the advantage of reduced borehole influences and is used to evaluate formation porosity and identify gas zones and gas/liquid contacts.

Type of Log	Principle	Identification
Gamma-ray (“GR”)	Gamma-ray logs measure the natural gamma radiation	Used to identify lithology (distinguish shales from sandstones and carbonates). Also used for geologic correlations and for calculating the volume of shale in sandstone.
Spontaneous Potential (“SP”)	The SP curve records the electrical potential produced by the interaction of formation water, conductive drilling fluid, shales.	The SP is used to identify permeable beds, locate boundaries of permeable beds, aid in determining water resistivity and as an indicator of formation shaliness.
Resistivity Logs	Electric current is passed through the formation, and voltages are measured between electrodes. The measured voltages provide the resistivity.	Various formation resistivities are calculated: flush zone, uninvaded zones, fluid contacts and water saturation.
Microlog (“ML”)	Electric current is passed through the formation, and voltages are measured between two short-spaced electrodes with different depths of investigation. The measured voltages provide the resistivity	Comparison of the curves identifies mudcake which indicates invaded zones, thus permeable formations

Cased Hole Logs

The following table lists types of logs to run in cased hole conditions. Note, additional logs not included in this list may also be considered.

Table 2: Type of Cased Hole Logs

Type of Log	Principle	Identification
Casing Inspection Tools	The tool uses magnetic flux leakage or ultrasonic measurements to identify corrosion and defects in casing	Evaluation of casing apparent metal loss or gain and internal or external corrosion defects
CBL-VDL (casing bond and variable density log)	The principle of the measurement is to record the transit time and attenuation of an acoustic signal after moving though the borehole fluid and the casing wall. This log requires a fluid filled hole.	The CBL is used to evaluate hydraulic seal, cement to casing bond and coverage. The VDL is used to assess the cement to formation bond and to detect the presence of channels and gas intrusion.

Type of Log	Principle	Identification
CMT or CET (cement mapping or cement evaluation tool) or SBT	The tool uses the casing resonance in its thickness mode to give a very fine resolution.	The tool is used to identify cement presence and quality.
CCL (casing collar log)	The CCL is a magnetic device which is sensitive to the increased metal at a casing collar.	It is run with cased hole logs and is primarily used for depth control.
GRN (gamma ray-neutron)	Gamma ray logs record the natural radioactivity of the formation, less dense formations will appear to be slightly more radioactive.	The GR is used for correlation and gives lithology control. Neutron identifies gas behind pipe, porosity and fluid contacts.
Pulse Neutron	Tool measures response of various formations to the emission of generated neutrons.	The tool determines reservoir saturation, porosity, and borehole fluid.
Thru-tubing	Base on pulsed eddy current(PEC) physics principles.	The tool measures the response decay of the eddy current signals and can provide metal thickness information for multiple concentric strings of pipe.

Pressure Tests and Annulus Monitoring

SUMMARY

This standard addresses testing and monitoring associated with well integrity management, and is supported in detail by the procedures listed in the Reference Documents section.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

Safety:

Safety issues are addressed in each of the procedures referenced in the requirements below.

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REQUIREMENTS

1 Pressure Test (Mechanical Integrity Test (MIT))

Mechanical integrity tests (MIT) are hydrostatic pressure tests that demonstrate that the well casing, tubing, casing-tubing annulus and packer is capable of holding a pressure at the time the test was conducted. A pump truck is connected to the casing valve and fluid is slowly pumped until the annular pressure reaches the desired level. The tubing is pressure tested by setting a plug in the bottom of the tubing string and pumping fluid into the tubing until the pressure reaches the desired level.

NOTE: Notify the CalGEM at least 48 hours in advance of MIT per California PRC 1726.6(d).

The pressures test shall be conducted with a liquid approved by CalGem for one hour with initial pressure of at least 115% of maximum operating pressure (MOP) at the wellhead (CCR 1726.6.1(a)(4)) or the minimum yield strength of the casing and tubing, whichever is less. A passing pressure test meets the following criteria (CCR 1726.6.1)::

- The pressure test is conducted with a liquid (CCR 1726.6.1(a)(1)),
- Liquid additives other than brine, corrosion inhibitive or biocides require CalGEM advance approval (CCR 1726.6. (a)1(2))
- The column of fluid is free of excess gasses (CCR 1726.6.1(a) (2))
- the pressure loss in the first 30-minutes does not exceed 10% of the initial test pressure (CCR 1726.6.1(a) (5))
- the pressure loss in the second 30-minute interval does not exceed 2% of the pressure in the first 30-minute interval (CCR 1726.6.1(a) (5)).

A casing MIT test is to be performed on a well upon completion and for a well completed with tubing and packer, at a frequency of not less than one test every five years or as defined by regulation (CCR 1726.6(a)(3)). The frequency of test may increase or decrease based on the well's performance data and be documented. If, during the test interval the tubing and packer are removed and replaced, an MIT will be conducted prior to returning the well to service.

Results of the testing should be reviewed for accuracy and clear demonstration of integrity. Refer to procedures K, Pressure Test (Mechanical Integrity Test) Acceptance and Frequency and Z, Well Integrity Testing Regime Process Production Casing, for additional details.

If the pressure test is not successful, then CalGEM notification is required and the well shall not be used for injection or withdrawal without approval by CalGEM (CCR 1726.6(a)(3).

NOTE: Pressure Tests must be submitted to CalGEM within 30 days after being completed This is simply accomplished by the engineer uploading files to the CalGEM web site.

2 Annulus Monitoring and Data Collection

Monitoring of the well annuli for the presence of gas and pressure is completed daily and more frequent if determined necessary (CCR 1726.7(a)). Monitoring and evaluating of annuli pressure should at a minimum include the following:

- To minimize corrosion in the casing for wells where the casing is not cemented to surface, the annulus should be liquid filled and shut-in to prevent atmospheric corrosion.
- Any anomalous annulus pressures (CCR 1726.7(d)(3)(A)-(E)) must be reported immediately to the manager, supervisor, and engineer of Reservoir Engineering and to CalGEM.
- A plan of action should be developed to assess the anomalous pressure and could include taking the well out of service, collecting gas sample(s), and conducting a blow down test.
- A plan for the Well Annular Monitoring System and Response that includes:
    - Plan shall be submitted to CalGEM on an annual basis containing each wells setpoints.
    - General discussion on system construction and frequency of readings
    - Monitoring Process, thresholds, and Alarm Setpoint determination
    - Systems Alarms and threshold alarming setpoints (CCR1726.7(d)(2).
        - Tubing Setpoint shall not be higher than the maximum allowable injection pressure at the wellhead.
        - Tubing and Casing annulus Setpoint shall be determined based on annular fluid, initial pressure the packer was set, and operational configuration.
        - Wells historic anticipated surface pressure for each annuli
        - Annuli with zero anticipated surface pressure set point shall be 100 psi or 100 psi above the historic anticipated surface pressure
        - Listing of each wells setpoint
    - Data Validation
    - Roles and Responsibilities
    - System Limitation Risks
        - Weather related
        - Operational Clearances to operate the storage system
        - Equipment malfunction

        - Loss of power
        - Data transmission
        - Force Majeure
        - Archival of Historical Records
    - Regulatory Reporting
    - Record Keeping

Inspections, monitoring, and reporting for the unintended surface or cellar gas releases are conducted utilizing ambient area monitoring and inspection of the wellhead and cellar (CCR 1726.7(c) (f) and 1726.9) and as described in Standard 12, Wellhead Valve Operation, Maintenance and Inspection and Procedure J6, Wellhead (Christmas Tree) Pressure Monitoring

3 Tubing Casing Annulus (TCA) or Other Annuli Monitoring for Wells

Monitoring of tubing casing annulus (TCA) or other Annuli for the presence of gas and pressure is completed in accordance with Procedure N, Wellhead Annuli Pressure Collection (CCR 1726.7(a)), Procedure L8, Annular Pressure and Gas Sampling Monitoring, and Procedure J6, Wellhead (Christmas Tree) Pressure Monitoring.

An anticipated surface pressure (ASP) for each annulus should be determined based on a wells historical data and documented by GSAM.

Surface Casing Annuli: If a well's surface casing annulus (SCA) anticipated surface pressure is equal to or greater than 100 psig, the following shall at a minimum be completed

- Review and assess the relationship to Maximum Allowable Surface Casing Pressure (MASCP). MASCP is equal to the surface casing depth (feet) x 0.25 psi
- Collect gas sample(s)
- Conduct a surface casing blow down and build up test
- Evaluate and document results and action plan for the well

All Annuli: If a well's observed sustained surface pressure (OSSP) exceeds its anticipated surface pressure (ASP) by 100 psi (CCR 1726.7 (d)(2) and (3)), the following shall at a minimum be completed:

- Bleed off annular pressure and track pressure and time for the well to build up pressure back to the observed sustained surface pressure (CCR 1726.7(d)(3)(A)).
- Sample the fluids building up in the annulus (CCR 1726.7(d)(3)(B)).
    - Perform a chemical fingerprinting of the sample(s) or other diagnostic tests as determined necessary.
    - Evaluate the samples for migration of storage gas
    - Determine if the build up is due to migration of storage gas
    - Document assessment and review in wells action plan
- If not due to gas migration (CCR 1726.7(d)(3)(C):

    - An alarm set point for shall be set not to exceed 100 psi above the observed sustained surface pressure (OSSP) or pressure that would pose a risk to casing integrity (CCR 1726.7(d)(3)(C) and submit to CalGEM for approval.
    - Develop action plan if observed sustained surface pressure (OSSP) plus 100 psi pose a risk to the well to address the risk and submit to CalGEM for approval
    - Develop and document in action plan and long-term monitoring actions.
  - If due to gas migration (CCR 1726.7(d)(3)(E):
    - Develop plan to conduct further testing to determine the pathway of migration and take remedial action as needed
    - Submit plan to CalGEM for approval

Note, it is common to observe elevated pressures following an MIT that uses water immediately following the MIT due to expansion caused by high bottom hole temperatures. This is an example where pressures exceeding 100psi would not require a blow down test.

Initial pressure, final pressure, and blow down time should be recorded on all blow down testing and submitted to engineering. Based on blow down test results, any required remedial action including gas analysis and work overs will be determined and a decision to keep the well in service will be made by the manager, supervisor, and engineer. If a well is determined to be trending in an anomalous fashion, then the engineer shall develop an action plan, determine remedial steps if necessary, and evaluate for the cause, i.e., packer fluid leaking from the annulus versus cooling effects.

4 Records

RE:

- Maintain records on GSAM’s shared drive in folders specific to each well.
- File notifications and CalGEM acknowledgement in the CalGEM notification folder on the GSAM “G” drive

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

Observed sustained surface pressure (OSSP) – any validated pressure reading recorded used in monitoring.

Anticipated surface pressure (ASP) – pressure determined based on historical data and trending to utilize for responding to potential gas migration

IMPLEMENTATION RESPONSIBILITIES

GSAM integrity management engineers

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3

Reference Documents

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

GSAM Procedure K7, Mechanical Integrity Test Acceptance and Frequency

GSAM Procedure L8, Annular Pressure and Gas Sampling Monitoring

GSAM Procedure N10, Wellhead Annuli Pressure Monitoring

GSAM Procedure Z, Well Integrity Testing Regime Process – Production Casing

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 10 of the Underground Storage Risk and Integrity Management Plan,

Pressure Tests and Annulus Monitoring

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 10 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Corrosion Monitoring and Evaluation

SUMMARY

This standard addresses the elements of corrosion monitoring and evaluation (including risk assessment) performed at storage facilities regarding the potential for corrosion and the effectiveness of mitigative measures. (CCR 1726.3)(d)(4)).

Corrosion monitoring data is also utilized to establish integrity assessment priorities, and the results of integrity assessments are used to further evaluate the effectiveness of the corrosion control program at storage facilities. Elements of the corrosion monitoring and evaluate program are discussed below.

Corrosion monitoring and evaluation addresses the following:

- Evaluation of tubular integrity and identification of defects caused by corrosion or other chemical or mechanical damage. (CCR 1726.3(d)(4)(A))
- Corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures (CCR 1726.3(d)(4)(B))
- Annular and packer fluid corrosion potential (CCR 1726.3(d)(4)(C))
- Corrosion potential of current flows associated with cathodic protection systems (CCR 1726.3(d)(4)(D))
- Corrosion potential of all formation fluids, including fluids in formations above the storage zone (CCR 1726.3(d)(4)(E))
- Corrosion potential of uncemented casing (CCR 1726.3(d)(4)(F))

TARGET AUDIENCE

Gas Storage Asset Management

Facility Engineering (FIMP / C&P AF)

TIMP (TP AF)

GPOM

Corrosion Dept

Safety:

Safety issues are addressed in each of the procedures referenced in the requirements below.

Corrosion Monitoring and Evaluation

TABLE OF CONTENTS

SUBSECTION TITLE PAGE

REQUIREMENTS

1. Tubular Integrity

Evaluation of tubular integrity and identification of defects caused by corrosion, erosion or other chemical or mechanical damage is performed by using a casing inspection tool and visual inspection during well reworks (CCR 1726.3(d)(4)(A)).

For more details on casing inspections, refer to Procedure S15 Procedure - Casing Inspection Logging and Data Assessments.

During well reworks a visual inspection is performed on tubing for apparent external corrosion including:

- Corrosion in the threads of the tool joints
- Apparent pits and holidays
- Excessive rust and scales

The frequency of wall thickness monitoring should be evaluated using risk assessment and in alignment with Procedure Z, Well Integrity, Testing Regime Process – Production Casing, Procedure C, Casing Inspection Survey Frequency Decision Tree and Standard E1B, Tubular Design (section 5.3 Special Considerations Description (Corrosion)).

2. Wellbore Produced Fluids and Solids

Gas, liquid, and solids samples will be collected from active flow lines during withdrawal season to evaluate the corrosive potential of the product stream (CCR 1726.3(d)(4)(B)) see Fluids Management Standard, Section 4 – Reservoir Fluid Sampling, Quality, and Analysis, . Liquid sample collection points are currently limited to comingled product streams; however, piping modifications are being evaluated to facilitate liquid sampling from individual flow lines. Corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures is discussed below.

2.1. Operating Pressure

Minimum withdrawal flow rates are established to lift fluid from the bottom of the well to the surface. Fluid production is anticipated for wells as during withdrawal operation to meet demand.

Corrosion Monitoring and Evaluation

As the corrosive potential of produced liquids is related to operating pressures, pressures will be recorded (Procedure L8, Annular Pressure and Gas Sampling Monitoring and Procedure N10, Wellhead Annuli Pressure Monitoring) during each gas sampling event to further evaluate the corrosion potential of produced gas and liquids. Refer to Procedure L8, Annular Pressure and Gas Sampling Monitoring.

2.2. Gas Sampling

Corrosion evaluations may be performed using gas sampling results for water vapor, carbon dioxide, and hydrogen sulfide content. Carbon dioxide and hydrogen sulfide concentrations are converted to partial pressures to further evaluate the corrosion potential based on reservoir pressure.

Gas samples are collected at each observation wellhead monthly to establish a baseline for a gas withdrawal season. PG&E has historically spot sampled gas quality at wellheads and historic data indicates minimal changes in gas quality during the withdrawal season. Results of the baseline sampling are evaluated to determine whether changes in the sampling frequency can be supported and if warranted are recommended in the annual inventory reports.

Additionally, gas sampling may be performed at I/W wells in response to an annular condition per Procedure L8, Annular Pressure and Gas Sampling Monitoring.

2.3. Produced Liquid / Sludge Sampling

Liquid sample collection points are currently limited to comingled product streams; however, piping modifications are being evaluated to facilitate future liquid sampling from individual flow lines, see Fluids Management Standard, Section 4 – Reservoir Fluid Sampling, Quality, and Analysis. Produced fluids are collected and analyzed per PG&E's Sampling Plan - Produced Fluid Collection for Disposal at Class II Injection Wells from a comingled source managed by the Environmental department (Consult with Environmental Department on the transportation and handling of produce liquid and sludge).

PG&E has historically sampled liquids at traps / drains / separators installed downstream of individual flow lines. Once piping modifications to the facility are made, the results of the baseline sampling will be evaluated to compare the corrosive potential of produced liquids from individual wells and flow lines to historic data obtained from the comingled product stream. This analysis will determine whether changes in the sampling frequency and / or locations can be supported.

Additionally, in alignment with each specific storage field Well Risk Evaluation and Construction Standard Implementation Plans, PG&E is in the process of installing individual well sampling drip pots and coupons to allow for individual well fluid sampling that will be installed from 2019-2025.

2.4. Sand Inspections

When gas wells produce gas at high velocities in the tubing or casing, any sand that is picked up in the flow stream becomes a potentially destructive element. Sand that is blasted against the piping, valves, chokes, or other parts of the system can destroy equipment in a very short time. Further, the presence of sand is an indicator of a potential failure of the well's gravel pack and screen liner to prevent sand production. The sand inspections occur twice during the winter withdrawal period under a standard clearance: typically, once in January and once in March. If sand is detected, Reservoir Engineering will evaluate whether to reduce rate, shut-in a well, schedule to re-gravel pack and install a new screen liner, or another appropriate mitigation.

Refer to the Procedure H4, Sand Inspection for further details.

3. Annular Packer Fluid

To minimize the corrosion potential of the annular between the casing and the tubing, packer fluid with corrosion inhibitor is placed in annular and packer behind the scab liner / inner string (CCR 1726.3(d)(4)(C)). Annular filled with packer fluid can minimize the annular exposure to atmospheric corrosion (oxidation), see Fluids Management Standard, Section 3 – Completion Fluid Sampling, Quality, and Analysis.

4. Current Flows Associated with Cathodic Protection Systems

Cathodic Protection (CP) is an electrochemical process that when applied adequately can greatly reduce corrosion rates of metallic structures. The external surface of well casings and production strings that are in contact with the soil at gas storage facilities are provided external corrosion protection by an impressed current cathodic protection system. Impressed current rectifiers are monitored bimonthly and structure to electrolyte potential testing is conducted annually to determine the effectiveness and adequacy of the CP system. Results are integrated by PG&E's Corrosion Department with RE involvement with downhole metal loss and casing potential logs to further evaluate the performance of the corrosion control systems (CCR 1726.3(d)(4)(D)).

5. Formation Fluids

Corrosion potential of all formation fluids is further reduced when cement is placed between the formation and production casing to isolate fluid from contacting the casing from the above storage zone (CCR 1726.3(d)(4)(E)). For more details, refer to Standard E, Design and

Specifications for Construction of Natural Gas Storage Wells and see Fluids Management Standard, Section 4 – Reservoir Fluid Sampling, Quality, and Analysis.

6. Uncemented Casing Annuli

Methods to monitor corrosion potential of the uncemented casing annuli include running MFL, Ultrasonic, and Caliper logs to determine metal loss and a decrease in casing thickness due to corrosion or erosion (CCR 1726.3(d)(4)(F). Refer to Procedure S, Casing Inspection Logging and Data Assessments and Procedure Z, Well Integrity Testing Regime Process – Production Casing.

7. Pipeline and Other Facilities

7.1. Pipeline Assessments

Assessments of the transmission pipe associated with storage fields is addressed in PG&E Transmission Integrity Management Program (TIMP). Refer to Section 3 of Standard 1 for an overview of this and Section 4 Roles and Responsibilities.

PG&E applies the Transmission Integrity Management Program (TIMP) to all transmission pipe, including pipe operating within storage fields meeting the requirements of 49 CFR part 192 Subpart O. This includes High Consequence Area (HCA) analysis, threat identification and risk assessment on all transmission pipe on an annual basis. For HCAs, assessments and reassessments of the identified threats are performed within the code-prescribed timeframes and may include External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA), Stress Corrosion Cracking Direct Assessment (SCCDA), In-Line Inspection (ILI), and Hydrostatic Testing. In addition, PG&E is currently considering a threat assessment program to assess non-HCA pipe in exceedance of minimum code requirements.

7.2. Atmospheric Coating Systems

Above grade piping, to include wellheads and gas measurement / treatment equipment, is protected with atmospheric coating systems that are inspected on three-year intervals.

7.3. Cathodic Protection

Buried and/or submerged piping is protected by underground coating systems and impressed current cathodic protection systems that are monitored at intervals described in Section 13.4. Cathodic Protection (CP) is an electrochemical process that when applied adequately can greatly reduce corrosion rates of metallic structures. The external surface of well casings and production strings that are in contact with the soil at gas storage facilities are provided external corrosion protection by an impressed current cathodic protection system. Impressed current rectifiers are monitored bimonthly and structure to electrolyte potential testing is conducted annually to determine the effectiveness and adequacy of the CP system.

7.4. Internal Corrosion Site Specific Plans

Internal corrosion (IC) monitoring, flow modeling, and nondestructive examination (NDE) are utilized to monitor the threat of IC. Identified sections of high risk pipeline areas are targeted for additional inspection by using radiography and/or ultrasonic thickness (UT) testing to further evaluate the potential for internal corrosion. Additional monitoring may include weight loss coupons, UT monitoring probes, and/or electrical resistance (ER) probes will be utilized as required. Other metallic facilities that store or transport gas (such as filter separators) are inspected for internal corrosion on a risk-based schedule maintained by Facilities.

Liquid samples are analyzed, as available, for corrosive constituents including, but not limited to: pH, chlorides, and bacteria (types that initiate microbiologically induced corrosion).

PG&E conducts sand inspections to monitor for sand that may cause erosion corrosion damage in the pipelines and downstream equipment as described in Section 2.4 above.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Gas Storage Asset Management integrity management engineers

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Corrosion Monitoring and Evaluation

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

GSAM Standard 9, Mechanical Integrity of Wells (Section 3): Casing Inspection Tools

GSAM Standard 14B, Well Risk Assessment and Relative Risk Ranking

GSAM Procedure C, Casing Inspection Survey Frequency Decision Tree

GSAM Procedure E1, Design and Specifications for Construction of Natural Gas Storage Wells

GSAM Procedure H4, Sand Inspection

GSAM Procedure L8, Annular Pressure and Gas Sampling Monitoring

GSAM Procedure Z, Well Integrity Testing Regime Process – Production Casing

GSAM Fluids Management Standard

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 13 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

Corrosion Monitoring and Evaluation

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 13 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Evaluation of Operational Factors for Wells and Attendant Facilities

INTRODUCTION

This standard addresses the evaluation and management of wells and attendant facilities, and protocols include the following (CCR 1726.3):

- monitoring of casing pressure changes at the wellhead,
- analysis of facility flow erosion,
- hydrate potential,
- individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures,
- analysis of the specific impacts that the intended operating pressure and temperature range could have on the corrosive potential of fluids in the system.

Evaluation and management of attendant facilities are incorporated into risk assessment of each well (Standard 14B, Well Risk Assessment and Relative Risk Ranking). Further, the requirements in 49 CFR 192 are addressed in the following sub-sections.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

Gas Pipeline Operation and Maintenance (GPOM)

Facilities Engineering (FIMP / C&P AF)

Corrosion Dept (CD)

SAFETY

Safety issues are addressed in each of the procedures referenced in the requirements below.

Evaluation of Operational Factors for Wells and Attendant Facilities

TABLE OF CONTENTS

SUBSECTION TITLE PAGE

REQUIREMENTS

1. Casing Pressure and Flow Changes at the Wellhead

Casing pressure and deliverability flow changes at the wellhead are monitored and evaluated. For more details, refer to Procedures L, M, N listed in the Reference Documents section towards the end of this standard.

2. Facility Flow Erosion

Flow erosion mitigation is incorporated into facility design, past and present. Examples include targeted tees and long radius bends/sweeps.

Flow erosion is monitored through

- Sand inspections (ref Procedure H),
- Wall thickness inspections (Standard 9, Section 2.1),
- Corrosion Monitoring and Evaluation Standard 13, Section 1, Section 2, and Section 7.1

The frequency of downhole wall thickness monitoring is evaluated using risk assessment Procedure C for casing inspections.

3. **Hydrate Potential**

   Hydrates can form due to a combination of temperature, gas composition, and pressure. Hydrates pose a risk to the system and can plug or rupture lines and can cause extensive equipment damage. In general, hydrate formation can be prevented using dehydration systems, heaters, insulated/heat traced lines, and methanol injection. All three of PG&E storage facilities use gas dehydrators as a way to minimize free water in the gas flow. In addition, Los Medanos has heaters located at well meters. Also, at McDonald Island a majority of aboveground well lines are insulated and heat traced, and the facility uses a methanol injection system to inhibit and suppress hydrate formation (CCR 1726.3(d)(8)).

4. **Facility Component Capacity and Fluid Disposal Capability**

   Facility components are designed (sized) for station maximum capacity and fluid disposal systems for respective capacities. PG&E relies on offsite disposal of produced fluids and does not have disposal wells at any of its three facilities (CCR 1726.3(d)(5)). See Standard 13F, Fluids Management

5. **Operating Pressure and Temperature Range**

   Minimum withdrawal flow rates are established within the operating pressure range to lift fluid from the bottom of the well to the surface. Fluid production is necessary to allow the wells to continue to meet customer demands. Each well shall have established well operating parameters within limits (CCR 1726.3(d)(5)). This should include pressures, temperature, and/or flow rates to minimize flows that could lift sand or erosion due to velocity (CCR 1726.3(d)(5)).

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM integrity management engineers

Evaluation of Operational Factors for Wells and Attendant Facilities

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

GSAM Standard 9. Mechanical Integrity of Wells, Section 2.1,

GSAM Standard 13, Corrosion Monitoring and Eval, Section 1, 2, and 7.1,

GSAM Standard 13F, Fluids Management

GSAM Standard 14B, Well Risk Assessment and Relative Risk Ranking

GSAM Procedure 14C, Relative Risk Ranking of Wells

GSAM Procedure C, Casing Inspection Survey Frequency Decision Tree

GSAM Procedure L8, Annular Pressure and Gas Sampling Monitoring

GSAM Procedure M9, Individual Well Performance Monitoring

GSAM Procedure N10, Wellhead Annuli Pressure Monitoring

GSAM Procedure H4, Sand Inspection

APPENDICES

N/A

ATTACHMENTS

n/a

Evaluation of Operational Factors for Wells and Attendant Facilities

DOCUMENT RECISION

This replaces Section 14.1 through .5 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 14 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Well Risk Assessment and Relative Risk Ranking

INTRODUCTION

This standard addresses the requirement for each underground gas storage project to develop a well-by-well risk assessment. The requirement for specific risk management plans and define the methodology to conduct a risk assessment to evaluate threats and hazards associated with the operation (see Standard 1 Section 10 – Asset, Threat, and Risk Management).

The methodology for well-by-well risk assessment is included in the methodology that should consider at least the following (CCR 1726.3(c)):

(1) Identification of potential threats and hazards associated with operation of the underground gas storage project, including identification of the most important potential accident scenarios associated with operation of the underground gas storage project **(see Standard 1 Section 10.1 – contained in Threat Matrix).**

(2) Quantitative risk assessment of the probability of threats and hazards and their consequences, using an appropriate methodology identified by the operator that includes **(see Standard 1 Section 10.1.1 – contained in Asset Management Plan and Risk Register).**

  (A) Evaluation of the frequency and range of consequences, including estimates of the uncertainties in the numerical values.

  (B) Identification of the principal equipment failures, external initiating events, and operational errors associated with threats and hazards, and quantification of the impact of these occurrences on the probability of and consequences of the threats and hazards; and

  (C) Identification of the engineered or natural features that most affect the extent of the consequences of threats and hazards, and a quantification of their relative roles, including an estimate of the uncertainties in the quantification.

(3) Identification of possible prevention and mitigation protocols to reduce, manage, or monitor risks, including evaluation of the efficacy and cost-effectiveness of the prevention protocols **(see Standard 1 Section 10.2**).

(4) Risk assessment on a well-by-well basis, to the extent that risks identified are specific to wells;

(5) Prioritization of risk prevention and mitigation efforts based on potential severity and estimated likelihood of occurrence of each threat **(see Standard 1 Section 10.3 – contained in Asset Management Plan and Risk Register).**

(6) Selection and implementation of prevention and mitigation protocols; **(see Standard 1 Section 10.2 – contained in Asset Management Plan and Threat Matrix).**

(7) Documentation of the risk assessment process, including description of the basis for selection of Prevention and mitigation protocols **(see Standard 1, Section 9.3).**

(8) Data feedback and validation throughout the risk assessment process **(see Standard 1 Section 10.3 – contained in Asset Management Plan)**.

(9) Regular, periodic risk assessment reviews to update information and evaluate the effectiveness of prevention and mitigation protocols employed, which shall occur not less than once every three years and in response to changed conditions or new information**(see Standard 1 Section 10.3 – contained in Asset Management Plan and Risk Register).**

TARGET AUDIENCE

Gas Storage Asset Management

- Integrity management engineers
- Well work project managers
- Technical work supervisors

GPOM

Facilities Engineering (FIMP / C&P AF)

Corrosion Dept

SAFETY

Safety issues are addressed in each of the procedures referenced in the requirements below.

TABLE OF CONTENTS

Well Risk Assessment and Relative Risk Ranking

REQUIREMENTS

1. Well Risk Ranking

Reservoir Engineering shall complete a risk assessment on a well-by-well basis as follows:

- Identify the potential threats and hazards associated with operation of the underground gas storage project and each well, including identification of the accident scenarios associated with operation of the underground gas storage project.
- Complete a quantitative risk assessment of the probability of threats and hazards and their consequences, using a defined methodology that includes:
  (1) Evaluation of the frequency and range of consequences, including estimates of the uncertainties in the numerical values.
  (2) Identification of the principal equipment failures, external initiating events, and operational errors associated with threats and hazards, and quantification of the impact of these occurrences on the probability of and consequences of the threats and hazards; and
  (3) Identification of the engineered or natural features that most affect the extent of the consequences of threats and hazards, and a quantification of their relative roles, including an estimate of the uncertainties in the quantification.
- Identify possible prevention and mitigation protocols to reduce, manage, or monitor risks and how they may affect risk assessment.
- Complete a risk assessment on a well-by-well basis for the risks identified that are specific to wells.
  (1) Incorporate new data from baseline and re-assessments to further inform the review of other P&M protocols across the well population. After wells are baselined, reassessed or converted to tubing and packer, a well's new risk score will help inform prioritization of a full re-assessment in the target ranges explained in Procedure C, Casing Inspection Survey Frequency Decision Tree
  (2) For each gas storage well, evaluate the risk of each well and the change to a well's risks due to the employment of surface and/or subsurface automatic or remote-actuated safety valves is appropriate based on consideration of at least the following:
    i. The well's distance from dwellings, other buildings intended for human occupancy, or other well-defined outside areas where people may assemble such as campgrounds, recreational areas, or playgrounds;
    ii. Gas composition, operational pressures, total fluid flow, and maximum flow potential;
    iii. The distance between wellheads or between a wellhead and other facilities, and access availability for drilling and service rigs and emergency services;

iv. The risks created by installation and servicing requirements of safety valves;

v. The risks to and from the well related to roadways, rights of way, railways, airports, and industrial facilities;

vi. Proximity to environmentally or culturally sensitive areas;

vii. Alternative protection measures which could be afforded by barricades or distance or other measures;

viii. Age of well;

ix. The risks of sabotage;

x. The current and predicted development of the surrounding area as reflected in the local general plan, topography and regional drainage systems, and environmental considerations;

xi. Topography and local wind patterns; and

xii. Evaluation of geologic hazards such as seismicity, landslides, subsidence, and potential for tsunamis.

- Prioritize the risk prevention and mitigation protocols based on potential severity and estimated likelihood of occurrence on a well-by-well basis in a plan for implementation and the following:

  (1) The risk score of a well can impact the implementation a well is converted to tubing and packer configuration to eliminate a single point of failure as required by (CalGEM 1726.3 d 1)

  (2) Prioritization of well prevention and mitigation protocols for each year's well work program should consider the following work activities to ensure the safe operation of the facilities and wells:

    i. the schedule of reworks

    ii. the ability to effectively and efficiently conduct the work

    iii. minimization of unnecessary equipment mobilization

    iv. other station projects that impact deliverability

    v. reducing the amount of outage time at the storage facilities.

- Document the risk assessment process and results, including description of the basis of the plan for implementation including the following;

  (1) Complete a year over year comparison to evaluate a well's risk change and how effective are the prevention and mitigation protocols.

  (2) Complete reviews twice per year to update information and evaluate the effectiveness of the plan of implementation and sooner in response to changed conditions or new information

  (3) The following documents are companion to this standard and these plans above are living documents and are refreshed twice per year for work planning and as needed

based on continuous evaluation of data received as part of the P&M measures outlined within this plan:

- McDonald Island Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan.
- Los Medanos Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan
- Pleasant Creek Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan.

(4) These field specific plans above are living documents and are refreshed twice per year for work planning and as needed based on continuous evaluation of data received as part of the P&M measures outlined within this plan.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM integrity management engineers

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

- GSAM Standard 9. Mechanical Integrity of Wells, Section 2.1,
- GSAM Standard 11, Safety Valve Operation, Maintenance and Inspection Section 1
- GSAM Standard 13, Corrosion Monitoring and Eval, Section 1,
- GSAM Standard 14A, Evaluation of Operational Factors for Wells and Attendant Production Facilities
- GSAM Procedure 14C, Relative Risk Ranking of Wells
- GSAM Procedure C, Casing Inspection Survey Frequency Decision Tree
- GSAM Procedure L8, Annular Pressure and Gas Sampling Monitoring
- GSAM Procedure M9, Individual Well Performance Monitoring
- GSAM Procedure N10, Wellhead Annuli Pressure Monitoring
- GSAM Procedure Z, Well Integrity Testing Regime Process

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 14.6 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

Well Risk Assessment and Relative Risk Ranking

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 14 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Relative Risk Ranking of Wells

INTRODUCTION

This procedure addresses the determination of the relative risk ranking of wells that supports sequencing decisions on well work.

Individual well-by-well risk ranking allows PG&E to manage P&M programs to adequately address highest risk assets and prioritize capital projects accordingly. The relative risk ranking model database manages and tracks the inputs, both static and dynamic, to evaluate the relative risk of each well.

Continuous Evaluation (CE) is used to evaluate the integrity of each well based on data integration from both integrity assessments performed and routine maintenance, operations, and testing performed to evaluate asset condition and subsequent risk profile. Data collected from the P&M measures are used to inform the scoring assignments. Additionally, baseline casing assessment and reinspection data are input into the model. Reinspection frequency is based on the Underground Storage Risk and Integrity Management Plan, Procedure C – Casing Inspection Survey Frequency Tree.

Under the Final Rule (effective March 2020) issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and API RP 1171 incorporated by reference, operators shall develop a program to manage risk that includes a process to assess risk related to the storage operation on a consistent basis. Additionally, under the Final Regulations (effective October 2018) issued by the California Geologic Energy Management Division (CalGEM, previously known as the Division of Oil, Gas, and Geothermal Resources (DOGGR)) require operators to perform a risk assessment on a well-by-well basis (§1726.3(c)(2)(4)).

TARGET AUDIENCE

Gas Storage Asset Management

Reservoir Engineering is responsible for analyzing all the available asset data collected in the practices outlined in the Underground Storage Risk & Integrity Management Plan to evaluate the overall condition and exposure of each well asset.

SAFETY

Safety issues are addressed in each of the procedures referenced in the requirements below.

Relative Risk Ranking of Wells

TABLE OF CONTENTS

SUBSECTION TITLE PAGE

REQUIREMENTS (CCR 1726.3(C))

1. Steps Gas Storage Asset Management will perform

1. Review and update any changes to the methodology (Section 3), calculations(Section 4 and 5), and definitions based on a review of the risk ranking model, implementation plan structure, or Asset Family Owner input.
2. Update relative risk ranking and databases on GSAM drive with inspection and monitoring results from programs to mitigate risk (examples: sand inspections, pressure monitoring, pressure tests, noise temperature logging, casing inspection logging, etc.) -see Section 5 Consequence Scoring
    a. Modify proposed assessment plans based on relative risk ranking based on each wells risk score
    b. Incorporate changes that would prioritize a well over another or group of wells based on the engineer's knowledge into Implementation Plans and document justification for engineer change
    c. Make modification to Implementation Plans to maintain facility operability and document reason and those wells who plan of work is moved 12 months or longer into the future.
3. Update database and Tableau dashboards
4. Update database and Implementation Plan introductory documentation and supporting exhibits and tables.
5. Conduct a review with Asset Family Owner, GSAM Director, and stakeholders to validate the implementation plan achieves the following:
    a. Meets regulatory requirements

b. Determines need and usefulness of each well asset
c. Each well's relative risk has been determined
d. Review of the relative risk model changes or modifications if necessary
e. Plan is executable during the current calendar and subsequent year

6. Route Implementation Plan for approval through electronic system
7. Publish Implementation Plan update
8. Maintain records on GSAM c:\ drive

2. Publication Schedule of the Relative Risk Model

1. The model is maintained throughout the year as new data becomes available and the following schedule guides the formal publication/snapshot of the relative risk model.

Publication	Purpose
By July 31	Identifies/confirms well population scheduled for next two-year rework cycles
By January 31	Integrates previous season rework Integrates year end data to identify any emergent or break in work to be addressed in the coming year and confirms five-year outlook

3. Relative Risk Model Attributes Inputs

The following sections below outline the various attributes and inputs that are considered in the relative risk ranking analysis. The data includes both static and dynamic data; static data is unchanging and does not require annual review, whereas dynamic data is dependent on testing result inputs.

The risk score for each well is computed by summing the score components that impact likelihood of loss of containment and multiplying that value by the sum of the consequence score impacts to safety, environment, and reliability.

Likelihood Score Components	Consequence Score Components
• Usage Factor • Adjusted Rework Factor • Production Casing Condition Factor • Tubing and Packer Condition Factor • Monitoring and Inspection Condition Factor • Wellhead Security Factor • Natural Force Factor	• Well Rate Factor • Well Operation Factor • Wind Direction Impact • Proximity Factors: Occupied Structure, Offset Well, Road and Railway Proximity, Local/Adjacent Land Use, Water Proximity, Response to Well Incident • Well Configuration • Valve Factor

4. Likelihood Scoring Components

The likelihood scoring components include the following factors are a defined in the following subsections. The scoring component is shown in the shaded box within the section.

The scoring components are combined in the following equation:

Likelihood = (Usage Factor/5) + (Adjusted Rework Factor x 5)
+ (Production Casing Condition Factors)
+ (Tubing and Packer Condition Factors)
+ (Monitoring and Inspection Condition Factors)
+ (Well Security Factor)
+ (Natural Force Factors)

4.1. Usage Factor:

The usage factor is computed as described below: <<SMEs – numbers or bullets??>>

- Usage Factor: This score considers the impact of the duration of use over a well's life cycle, the prospect for human error via intervention activities, how the well has been used to account for levels of stresses the well has been subject to.

$$\text{Usage Factor} = \text{Average}\left\{ \text{Number of Years in Operation} \right\}$$

  - Well Operation: The current operational state in which the well is used. Wells will be identified as Injection and withdrawal (Inj/Wd), withdrawal only (Wd only), or observation (obs). The use of the well is dependent on construction and surface facility installments. Wells that are used for both Inj/Wd have a higher likelihood score as the stresses from injection and withdrawal activities are the highest. Wells used for Wd only do not experience injection forces, thus are scored lower. Wells used of observation do not experience dynamic loading and are scored lower at a 1.

    The following likelihood scoring is given based on identified well operation:

Injection/Withdrawal (IW) = 3
Withdrawal only (wd only) = 2
Observation (obs) = 1

4.2. Adjusted Rework Factor

This score is based on the knowledge of the casing condition and assigns a higher risk score to wells that have had intervention or rework activity and have not had a casing assessment performed. This accounts for the human impact and risk associated with rework activity, and elevates opportunities where the casing could have been impacted but the condition is unknown.

Rework Factor =	If casing condition not known	→	Number of Well Reworks
	If casing condition known	→	0.5 x Number of Reworks

4.3. Production Casing/Inner String Condition Factor:

The production casing condition factor is a summation of the following inputs for the production casing string. In wells that have been converted to tubing and packer, this element is considered the secondary barrier.

- Original Production Casing Wall Thickness: This score is based on the worst-case metal loss identified in a casing inspection survey (i.e. MFL or ultrasonic). In the case where a well has not been assessed, the highest score is assigned.

Unknown = 4

Class 3 or 4 = 3

Class 2 or general = 2

Isolated Class 1 or 2 = 1

- Inner String Production Casing Wall Thickness: This score is based on the worst-case metal loss identified in a casing inspection survey (i.e. MFL or ultrasonic) where an inner string has been cemented into place. In the case where a well has not been assessed, the highest score is assigned.

Unknown = 4

Class 3 or 4 = 3

Class 2 or general = 2

Isolated Class 1 or 2 = 1

- Production Casing Wall Thickness: If an inner string is in place to remediate an original production casing, this pulls the inner string production casing identified above. If the original production casing is still the active production casing string, this pulls the production casing from two items above.

Unknown = 4

Class 3 or 4 = 3

Class 2 or general = 2

Isolated Class 1 or 2 = 1

Relative Risk Ranking of Wells

- Source of Metal Loss on Production Casing: This identifies the source of any known metal loss and assigns the score to metal loss due to corrosion as 3. For wells where the condition is unknown, the highest score of 4 is assigned to elevate the risk for wells where the condition is unknown.

Unknown = 4
Corrosion (IC or EC) = 3
Mechanical = 2
None = 0

- Potential Production Casing Mechanical Leak Path: This score identifies possible leak paths that could lead to a loss of containment incident based on the construction of a well or known historic leak prone connections. This score takes into account the well's construction and whether or not a potential leak path is present. Uncovered perforations, such that they have not been remediated with a scab liner to mitigate risk, are given a score of 5. Uncovered stage collars, those not proactively or in mitigation covered with a scab liner, also present a potential leak path and are assigned a 4. Stage collars that have been remediated with an inner string, while still can be a potential leak path, are considered less risky and a score of 3 is assigned. A casing thread leak is scored as a 2.

Uncovered Perforations = 5
Uncovered Stage collar or thread leak = 4
Isolated (by cement or Inner String) Stage Collar = 3
Isolated casing thread Leak = 2
None Identified/Not Applicable = 1

- Dogleg Severity: This score is based on the percentage of dogleg severity(DLS). DLS is considered as the combined stresses across sections of high deviation are higher and are also prone to greater amount of casing wear from pipe tripping. The maximum % of DLS is considered in the risk score as a well with a section of pipe that has a high degree of DLS impacts the allowable stress limit of a well and reduces the amount of tolerable wall loss at the same performance rating.

m	*0% -5% = 1*
n	*5% -10% = 2*
o	*> 10% = 3*

- Inner String Installed: The presence of an inner string is included in the scoring as it adds risk by creating another potential leak path and additional element that requires monitoring.

p	*Yes, Installed = 2*
q	*No = 1*

- Cement Bond Log TOC: The cement bond log uses the input value from the TOC identifying the highest top of well bonded cement with relation to the surface casing shoe depth.

Full - 1
Inside SC - 2
Below SC - 3

4.4. Tubing & Packer Condition Factor

The tubing & packer condition factor is a summation of the following inputs:

- Tubing Wall Thickness: This score is based on the worst-case metal loss identified in an inspection survey (i.e. MFL or ultrasonic). This will only impact the score of wells that are converted to tubing and packer configuration.

Class 3 or 4 = 3
Class 2 or general = 2
Isolated Class 1 or 2 = 1
Not Applicable = 0

- Potential Tubing Mechanical Leak Path: This score is based on known thread leaks of the tubing.

Tubing thread Leak = 2
None Identified/Not Applicable = 0

Relative Risk Ranking of Wells

- Packer Condition: This score is based on how well a packer is sealing and if a known packer leak is present.

> *Known Leak=2*
>
> *Sealing/Not Applicable = 0*

4.5. Monitoring and Inspection Condition Factors:

The following monitoring and inspection data points/trends are combined for each well evaluation:

- Annular Condition Monitoring Plan: This score uses the presence of an annular condition monitoring plan to elevate the risk of a given well.

  Note: based on the annular testing performed, annular pressure can be managed and is typically not considered a hazardous situation.

> *Yes = 3*
>
> *No = 1*

- Sand Production: The sand inspections of each well is typically performed twice 7each year during withdrawal season. This score uses the historical sand inspection data and counts the number of inspections that have been a grade 3 or higher. This elevates the risk score of a well as it can be associated with higher erosion rates and gravel pack degradation.

> *Count of # of Grade 3 or more that have occurred since last rework*

- Gas Composition: This score takes into account the type of gas in the storage system and if corrosive constituents are present and could cause/accelerate metal loss features.

> *None = 0*
>
> *CO_2 = 1*
>
> *H_2S = 5*

Relative Risk Ranking of Wells

- Wellhead Flange Condition- known leak: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2 *No= 1*

- Wellhead Tubing head Condition- known leak: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2 *No= 1*

- Wellhead Hydraulic Port Leak Condition: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2 *No= 1*

- Known Hydrate Potential: This score is factored in for wells where hydrate formation on the system has been identified historically.

Yes, historically observed = 1 *No= 0*

Relative Risk Ranking of Wells

4.6. Wellhead Security Factor

The Wellhead security factor is a summation of the following inputs:

- Well Security: This score is based on security features installed at a given wellhead site or group of proximate wellheads. This score impacts the likelihood by taking into account the presence of a barrier that would limit access, thus reducing the likelihood of an external influence triggering a loss of containment event. Wells that have a fencing system are scored with a 1 and those without any type of physical barrier limiting access would be a 2.

  All of PG&E's wellhead sites are gated and fenced.

  Gated/Fenced = 1
  No= 2

- Wellhead Surface Impact Damage Protection: This score is based on security features installed at a given wellhead site to minimize opportunity for surface impact to the wellhead to occur and lead to an uncontrolled flow event. If no measures are employed, then the highest score is assigned as the wellhead has a higher risk of exposure to surface impact (i.e. vehicular). The likelihood score is reduced based on the level of surface protection provided whether a full circumferential system (i.e.. Bollards) be in place or partial (i.e. k-rail system on one side). Wells that are enclosed by a fence but do not have a barrier in place have a higher risk as maintenance vehicles drive within the fenced area.

  Full Barricade (k-rail/bollard) =1
  Partial Barricade (k-rail/bollard) = 2
  None (Fenced only) = 3

4.7. Natural Force Factors

The following factors are included and take into account naturally occurring outside force threats.

- Flooding: This score is based on the potential to experience flooding at a given storage facility.

  No= 0
  Yes=1

- Seismic: This score is based on the potential seismicity a given storage facility.

Low = 1
Med = 2
High =3

- Subsidence: This score consider is there is active subsidence at the facility.

No= 0
Yes=1

- Tsunami: This score considers the opportunity for a tsunami to impact the facility.

No= 0
Yes=1

- Landslide: This score considers if the facility and well site is situated where it could be impacted by landslides.

No= 0
Yes=1

5. Consequence Scoring Components

The consequence scoring components include the following factors as defined in the following subsections. The scoring component is shown in the shaded box within the section.

The scoring components are combined in the following equation:

$$\text{Consequence} = [\,(0.25 \times \text{Well Rate Factor}) + (\text{Well Operation Factor}) + \Sigma\,(\text{Proximity Factors})\,] - [\,5x\,(\,(0.5\ \text{Configuration}) + (\text{Valve Factor})\,)\,]$$

5.1. Well Rate Factor

- Rate Factor: This is based on the max current rate at the time of publishing the risk plan. Twenty-five percent of the rating factors into the consequence score to account for the reliability impact with the loss of a well.

5.2. Well Operation Factor

- Well Operation: The operational consequence of an event is also impacted that renders the well unusable has a greater implication on operations and use of the storage field. Withdrawal only wells carry an intermediate scoring as the unavailability of the well poses a risk to deliverability. Observation wells are assigned the lowest value in this category as unavailability would not impose a risk to operations.

Injection/Withdrawal (IW) = 3
Withdrawal only (wd only) = 2
Observation (obs) = 1

5.3. Proximity Factors

- Wind Direction Impact: This score looks at a well's surface location with respect to the nearest located structure and the predominant wind direction. This score is considered high such that a large release of gas could have severe impact with ignition on an adjacent facility. The score is low such that the predominant wind direction is away from adjacent structures.

High = 3
Low = 1

- Occupied Structure: This score is based on the well's surface location and its proximity to an occupied structure.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

Relative Risk Ranking of Wells

- Offset Wells: This score is based on the well's surface location and its proximity to an adjacent wellhead.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Roads: This score is based on the well's surface location and its proximity to a road as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3
0-500 ft of Major Highway = 4

- Proximity to Railroads: This score is based on the well's surface location and its proximity to a railroad as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Major Airport: This score is based on the well's surface location and its proximity to a major airport as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

Relative Risk Ranking of Wells

- Proximity to Population Centers: This score is based on the facility's location and the buffer rings indicated in the scoring.

> 1 Mile =3
1-2 Mile =2
2-5 Mile =1
>5 Mile = 0

- Proximity to Body of Water: This score is based on the facility's location and the buffer rings indicated in the scoring.

> 1 Mile =3
1-2 Mile =2
2-5 Mile =1
>5 Mile = 0

- Local Area/Land Use: This score is based on the facility's location and the surrounding area activity.

Urban = 4
Residential = 3
Crop farming (Irrigation/fertilizer / Plane) = 2
Cattle farming = 1

- Response to Well Incident: This score is based on proximity of employees to recognize and be able to respond in the event of a well emergency. Manned facilities have a higher likelihood that a response would be fairly soon after an event started or signs of an event could be recognized to minimize the impact.

Unmanned-2
Facility Manned-1

Relative Risk Ranking of Wells

5.4. Valve Factor

This factor is used to reduce the consequence score by the mitigation employed by the presence and performance of a DHSV. The factor is computed in the following manner; each scoring component is listed and explained below.

$$\text{Valve Factor} = \left(\left(\frac{\text{DHSV-Csg deployed}}{\text{DHSV-Csg Condition} + 1} \right) + \left(\frac{\text{DHSV-Tbg deployed}}{\text{DHSV-Tbg Condition} + 1} \right) \right) \times \left(\frac{1}{1 + \text{DHSV CL-cond}} \right)$$

- Well Configuration Factor: This score is used to reduce the consequence such that the dual barrier configuration would reduce the impact on the consequence.

  This score is factored by 50% in the final algorithm.

T&C Flow -1
T&P - 4

- DHSV Casing (Csg) Deployment: This score considers the presence of a DHSV on the casing side. Once wells are converted to tubing and packer, there is only a DHSV installed on the tubing side.

Yes -1
No - 0

- DHSV Tubing (Tbg) Deployment: This score considers the presence of a DHSV on the tubing side. Once wells are converted to tubing and packer, there is only a DHSV installed on the tubing side. Note: not all wells require a DHSV to be installed based on the critical well definition.

Yes -1
No - 0

- DHSV Casing (Csg) Condition: This score sums the number of level 4 leak by tests results a valve has received since installation.

# of Level 4 since installation

- DHSV Tubing (Tbg) Condition: This score sums the number of level 4 leak by tests results a valve has received since installation.

# of Level 4 since installation

- DHSV Control Line Condition: This score sums the number of level 4 leak by tests results the control line has received since installation.

# of Level 4 since installation

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM integrity management engineers

GOVERNING DOCUMENT

GSAM Standard 1
GSAM Standard 14B

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

McDonald Island Underground - Storage Field: Well Risk Evaluation and Construction Standard Implementation Plan, July 2020

Relative Risk Ranking of Wells

Supplemental References: Procedures referenced in the requirements section above.

- GSAM Standard 9. Mechanical Integrity of Wells, Section 2.1,
- GSAM Standard 11, Safety Valve Operation, Maintenance and Inspection Section 1
- GSAM Standard 13, Corrosion Monitoring and Eval, Section 1,
- GSAM Standard 14A, Evaluation of Operational Factors for Wells and Attendant Production Facilities
- GSAM Standard 14B, Well Risk Assessment and Relative Risk Ranking
- GSAM Procedure C, Casing Inspection Survey Frequency Decision Tree
- GSAM Procedure L8, Annular Pressure and Gas Sampling Monitoring
- GSAM Procedure M9, Individual Well Performance Monitoring
- GSAM Procedure N10, Wellhead Annuli Pressure Monitoring
- GSAM Procedure Z, Well Integrity Testing Regime process

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This supplements Section 14.6 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

Relative Risk Ranking of Wells

DOCUMENT CONTACT

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted McDonald Island Underground - Storage Field: Well Risk Evaluation and Construction Standard Implementation Plan, July 2020 to this standalone procedure	Minor language changes were made for clarity. No substantial content changes were made

Additional Investigations

SUMMARY

This procedure addresses a variety of additional investigations and corresponding steps to be undertaken when evaluating field and well integrity.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

Gas Pipeline Operations and Maintenance (GPOM)

Safety:

n/a

TABLE OF CONTENTS

Additional Investigations

REQUIREMENTS

1. **Check well's cement bond log – top of cement and bond quality**

    1.1. If no bond log exists, consider obtaining one.

    1.2. Review well's squeeze history or related cement improvement or remediation efforts.

    1.3. Consider whether Any temperature surveys exist to denote top of cement?

2. **Check well's log history and performance data**

    2.1. Check Gamma-neutron, pulsed neutron or other nuclear log

    2.2. Check Noise, temperature, flowlog, or flow performance /problem assessment log

    2.3. Obtain annular fluid levels (AFL) and AFL history

    2.4. Review logs for any prior history of annular gas or gas out of zone (occurrences adjacent to collars or to DV tools; correspondence to areas of inspection survey defects)

3. **Check well's casing inspection history and visual inspection (i.e., photos, leak survey, etc.)**

    3.1. Check Type of survey, compare survey results to present log

    3.2. Find and assess other integrity surveys run (magnelog, cathodic profile logging?)

    3.3. Check Visual inspections of casing (shallow depths) or surface expressions of gas

4. **Review well records (including invoices or job tickets) for construction and rework history**

    4.1. Consider When was casing installed; scratchers or centralizers, other external or internal tools applied

    4.2. Check Wellhead and top joint replacements

    4.3. Check Any milling/drilling/spudding/cabling inside the casing

    4.4. Check Any casing pressure tests or mechanical integrity tests

    4.5. Check Cementing operations

    4.6. Check Size, cement, problems or surface and intermediate casing strings

    4.7. Check Natural hydrocarbon zones encountered while drilling

4.8. Check Other fluid flow or lost circulation zones encountered while drilling

4.9. Check Perforations

4.10. Check Stimulation treatments

4.11. Check Position of well in transmission pipe system; position relative to cathodic protection system rectifiers and anodes

5. Review well's annulus pressure history

5.1. Review Occurrences of pressure or flow

5.2. Review Other external evidence of problems (water well surveys, vegetation stress issues, odors, audible leaks reported, regulatory citations)

6. Other Considerations

If the file on a well is deficient in items listed above and the well's inspection survey shows defects increasing in magnitude and/or extent, run appropriate logs, or obtain tests and offset data to help assess the problem and promote solution.

If internal corrosion is evident, run mechanical caliper and/or video camera surveys at earliest possible convenience to confirm presence and magnitude of internal metal loss

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Gas Storage Asset Management

GPOM

GOVERNING DOCUMENT

GSAM Standard 1

Additional Investigations

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

n/a.

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Appendix B of the Underground Storage Risk and Integrity Management Plan, Rev 5.

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix B to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Casing Inspection Survey Frequency Decision Tree

SUMMARY

This procedure provides a decision tree for assessing factors and deciding on casing inspection frequency, and determination of apparent growth of anomalies.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

Corrosion Department (CD)

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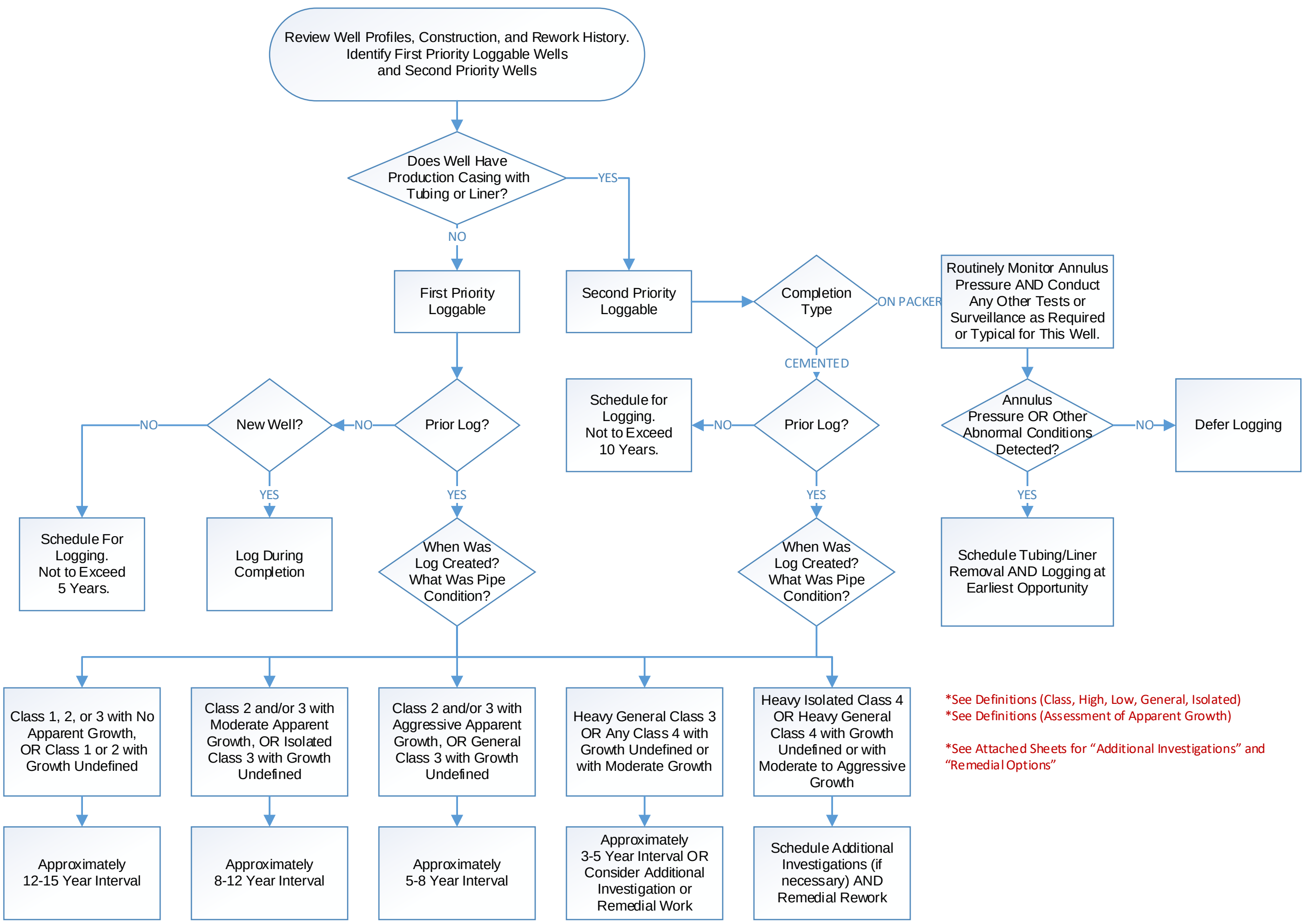
Casing Inspection Survey Frequency Decision Tree

STEPS

This figure provides the steps to be followed when considering casing inspection frequency, including consideration of the growth of anomalies.

1. Casing Inspection Survey Frequency Decision Tree



Casing Inspection Survey Frequency Decision Tree

2. Definitions - Class, High, Low, General, Isolated

Class
Defect rating based on interpreted percentage of pipe wall thickness lost;

Class 1: <= 20% wall loss
Class 2: > 20% wall loss and <= 40% wall loss
Class 3: > 40% wall loss and <= 60% wall loss
Class 4: > 60% wall loss

High
In the upper 50% of the Class

Low
In the lower 50% of the Class

General
Many defects along the axis and/or circumference of the casing;
Baker/Atlas generally considers defect clusters appearing in nearly 40% or more of the sensors to be “general corrosion”

Isolated
Single flux leakage anomalies found by individual sensors or at most on less than 30 – 40% of sensors (which may be adjacent defects or single larger defects)

Internal
Anomalies on the internal wall of the casing, identified by eddy current anomalies corresponding to flux leakage anomalies on the same sensor pads; generally, the eddy current anomaly should have a signature or response level beyond background noise for any joint of casing

Outer or External
Anomalies on the external or outside wall of the casing. Identified by lack of eddy current anomalies on the same sensor pads.

3. Definitions - Assessment of Apparent Growth

To be used when comparing a survey log to prior survey logs.

Pit Depth
Interpretations of metal loss from flux leakage measurements are at best within +/- 10 – 15% of actual metal loss (this could be closer to 10 – 15% for isolated pitting and 15 – 20% for general corrosion)

Therefore, let WTp = percent metal loss in present survey
WTn = percent metal loss in earlier survey
Yp = year of present survey
Yn = year of earlier survey

Then,

Maximum Rate of Apparent Change is:

[(WTp + 15%) – (WTn – 15%)] / (Yp – Yn)

And Minimum Rate of Apparent Change is:

[(WTp – 15%) – (WTn + 15%)] / (Yp – Yn)

Rates of Change > 3 – 4% + wall thickness per year = AGGRESSIVE
Rates of Change in the 1 – 3% wall thickness per year = MODERATE
Rates of Change < 1% wall thickness per year = LOW

Holistic Qualitative Review of Anomaly Occurrence and Density

In comparing the present survey to an earlier survey, does there appear to be a greater number of defects, a greater density of defect, or a growth in the circumferential or axial extent of defects?

How does the present survey compare to prior surveys in regard to eddy current anomalies or response to casing jewelry (scratchers, centralizers, etc.)?

END of Requirements

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, GSAM

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3.

Casing Inspection Survey Frequency Decision Tree

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix C in Underground Storage Risk and Integrity Management Plan, Rev 5.

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix C to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Remedial Options and Decision Tree

SUMMARY

This standard addresses the considerations and decision processes to address anomalies, features or circumstances that may or certainly require remediation associated with the maintenance of well and reservoir integrity.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

Gas Pipeline Operations and Maintenance (GPOM)

SAFETY

n/a

TABLE OF CONTENTS

SUBSECTION TITLE PAGE

Remedial Options and Decision Tree

REQUIREMENTS

1. Remedial Options

1.1. Figure 1 is provided to outline the decisions in determining the remedial options if necessary based on inspection and historical information.

Note: Any pipe recovered in remedial operations should be inspected and selected pieces set aside for delivery to Applied Technology Services (ATS) for detailed metallographic analysis and pit depth measurement. They may:

a Clean and photograph the pipe.
b Measure pit depth and geometry
c Measure unaltered pipe wall thickness
d Perform tensile tests on unaltered pieces of casing

Also note: Make sure that casing conditions have been properly assessed to remove the influence of conditions on log interpretation:

e Does casing need to be washed prior to logging? (past history may indicate a need)
f Were significant defect areas repeated?
g Were all background checks and cross checks made against well construction data and rework records?

2. Remediation Decisions

2.1. Based on metal loss and geometry interpretation from casing inspection logs a determination on the type of remediation or plug and abandon well .

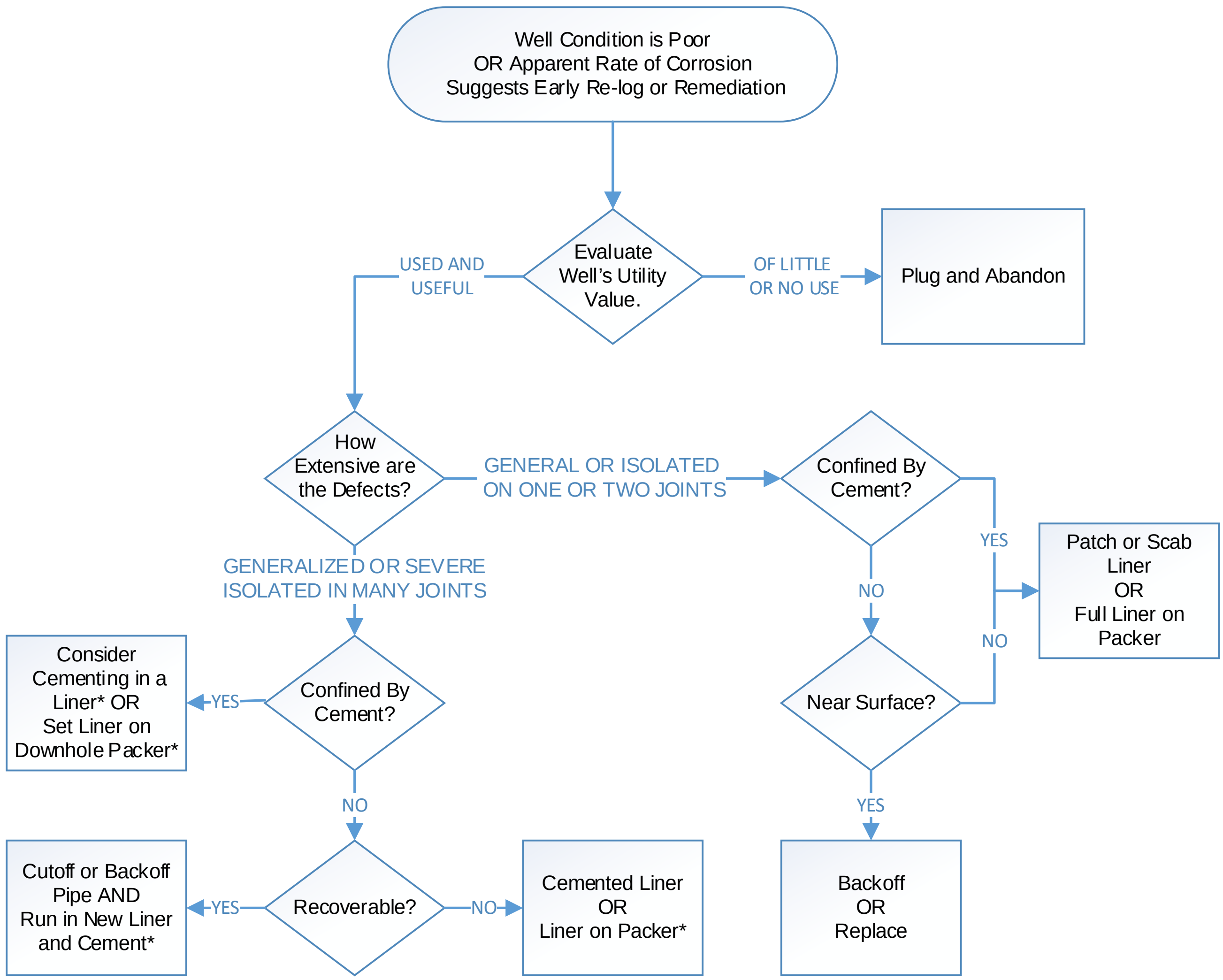
2.2. Inspection log results should be compared to previous survey to establish rough approximate metal loss and extensiveness of defects.

2.3. Based on pressure testing program determine the threshold for failure of typical pipe sizes and pitting geometries, whether casing is confined by cement, and depth.

2.4. Either remediate or schedule for a shorter-frequency re-log based on approximate metal loss and on nature of defect patterns (geometry and location), pressure testing to 115% of the well’s Maximum Allowable Operating Pressure (MAOP), and a complete review of the well’s operating history. This history is in a variety of records on the GSAM shared drive for the well, and in Simplicity (Gas System Operations SCADA records).

Remedial Options and Decision Tree

Figure 1: Remediation Decision Tree



*If lining or tubing of the well will have a significant and adverse impact to well and field deliverability, consideration can be given to drilling additional or replacement wells with or without plugging of the well with corroded casing

END of Requirements

Remedial Options and Decision Tree

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM

GPOM

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Appendix D of the Underground Storage Risk and Integrity Management Plan, Rev 5.

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

Remedial Options and Decision Tree

DOCUMENT CONTACT

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix D to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Mechanical Integrity Test Acceptance and Frequency

SUMMARY

This procedure sets forth the pressure testing process that PG&E utilizes for performing and assessing mechanical integrity testing of storage field gas wells.

TARGET AUDIENCE

Storage asset family reservoir engineers, project managers and supervisors.

GPOM staff (for information)

TABLE OF CONTENTS

Mechanical Integrity Test Acceptance and Frequency

REQUIREMENTS

1 Pressure Testing Process (CCR 1726.6.1)

1.1 Engineers will perform a calculation to determine if the casing based on an assessment of the metal loss with a casing inspection log can withstand a minimum pressure of 115% of the wells maximum allowable operating pressure.

1.2 If determination of pressure test shows remaining strength is less than 115% then engineers will determine next steps.

1.3 If determination of pressure shows remaining strength is greater than 115% engineers will determine the initial maximum test pressure to apply to the wells.

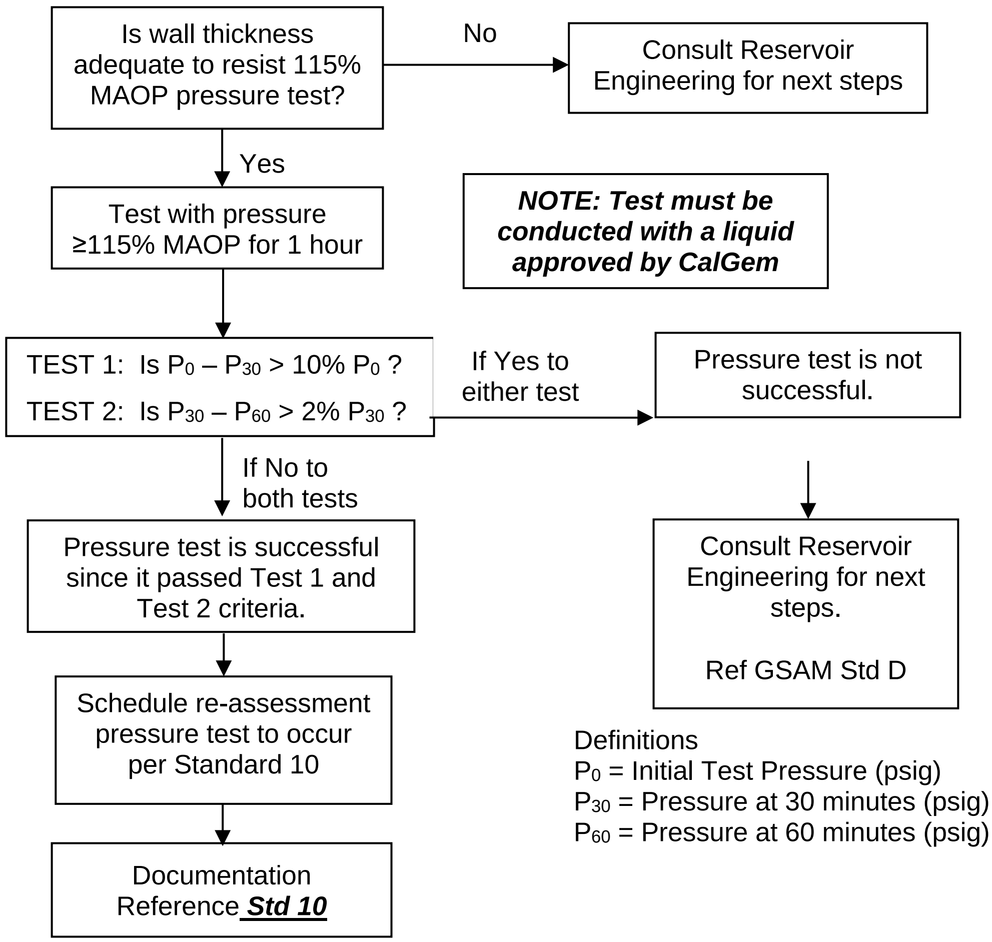
1.4 Perform Test and Document results

1.5 If pressure test is not successful, consult reservoir engineering for next steps

1.6 Reservoir Engineering reviews results and consults Remediation Decision Tree (D Standard - Remedial Options and Decision Tree) to remediate any found defects or plug and abandon the well

Mechanical Integrity Test Acceptance and Frequency

Use the following flow chart for PG&E's pressure testing process for performing and assessing MIT testing.



2 Re-assessment testing

Schedule re-assessment testing based upon the results of the results of the pressure test or as prescribed by regulation. The frequency of reassessment testing is decided by Reservoir Engineering based on the outcome of the test. If integrity issues arise as a result of the pressure test, regulatory agencies are to be notified.

END of Requirements

Mechanical Integrity Test Acceptance and Frequency

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

Standard 10, Casing Pressure Tests and Annulus Monitoring Standard

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

Standard 10, Casing Pressure Tests and Annulus Monitoring

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Underground Storage Risk and Integrity Management Plan, 7/10/20 Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Mechanical Integrity Test Acceptance and Frequency

Lucy Redmond, Director, GSAM

Document Contact

Larry Kennedy, Strategic Planning Chief, GSAM

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix K7 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Casing Inspection Logging and Data Assessments

SUMMARY

Purpose: This procedure provides standards and procedures for casing inspection logging and data assessments.

What: The Casing Inspection Logging provides a holistic program to ensure compliance with requirements for well casing integrity monitoring.

Why: Gas storage wells may be in service for many years. Therefore, it is prudent to choose and employ a design life and to monitor and maintain the integrity over this life to manage risks within design limits and to prevent gas leakage. Methods utilized to assess and prevent future casing failures and gas releases include storage well logging.

NOTE: Logs must be submitted to DOGGR within 30 days after being run in a well.

NOTE: Notify CalGEM at least 48 hours in advance of running the log survey per California PRC 1726.6(d).

TARGET AUDIENCE

Gas Pipeline Operation and Maintenance (GPOM) initiates clearances

Contractor performs testing services.

Gas Storage Asset Management (GSAM) - Reservoir Engineering group (RE)
- supervise on-site surveys.
- review survey data for reasonableness and completeness.
- evaluate survey data and recommends course of actions, if any.

Corrosion Department (CD) performs assessments

TABLE OF CONTENTS

Casing Inspection Logging and Data Assessments

STEPS

1. Logs

Wells are logged to identify potential problems and may include the following types of logs (type of log/survey identified in parenthesis.

- Reductions to casing wall thickness (casing inspection tools)
- Caliper
- Identification of gas presence behind the casing (gamma ray neutron – GRN) (CCR 1726.7(b)(2)(D))
- Presence of a corrosion cell (casing protection profile – CPP)
- Temperature Logs
- Noise Logs
- Downhole video cameras and/or downhole video side view cameras
- E-Log-I Surveys

In addition, for future new storage wells certain logs shall be considered to be run during drilling and completion. The list of logs to consider, principle (how the log works), and the identification (purpose of the log) are presented in Standard 9, Mechanical Integrity of Wells, Appendix 1.

1.1. Open Hole Logs

- Caliper
- Density w/Pe (Litho-Density)
- Compensated Neutron Log (CNL)
- Spontaneous Potential (SP)
- Gamma Ray (GR)
- Resistivity Logs (Dual-Induction or Array Induction)
- Microlog (ML)

1.2. Cased Hole Logs

- Casing Inspection Tools (i.e., Vertilog, MicroVertilog, High-Resolution Vertilog, Caliper, and Ultrasonic inspections)
- Cement Bond Log/Cement Mapping Tool with Gamma Ray and Casing Collar Locator or Segmented Bond Tool with Gamma Ray and Casing Collar Locator
- Base line TDT/PDK with Gamma Ray and Casing Collar Locator or Gamma Ray Neutron with Casing Collar Locator

2. Casing Inspection Tools and CP

Casing Inspection Tools and CPP are beneficial to get a baseline on the condition of the casing and the following criteria summary should be utilized:

2.1. Reservoir Engineer should review Procedure Z, Well Integrity Testing Regime Process for determining the requirements

2.2. Run baseline logs (Casing Inspection tool and/or GRN) on every well when the tubulars are removed.

2.3. Conduct required Follow-up casing inspections that are required on casing completed wells to assess the rate of change in pipe corrosion at time intervals to be determined by the condition of the pipe.

2.4. Conduct required Follow-up casing inspections on tubing and packer completed wells that are required when tubing is pulled for other remedial work and with consideration of the time interval between the remedial work and the last casing inspection tool run.

2.5. Run Noise and Temperature logs (annually) and GRN logs (periodic) on tubing and packer completed wells that do not have baseline casing inspections to identify changes in gas accumulation behind pipe and review

2.6. Coordinate and communicate with CD to confirm that CD judges' wells to be under protected by a cathodic protection system.

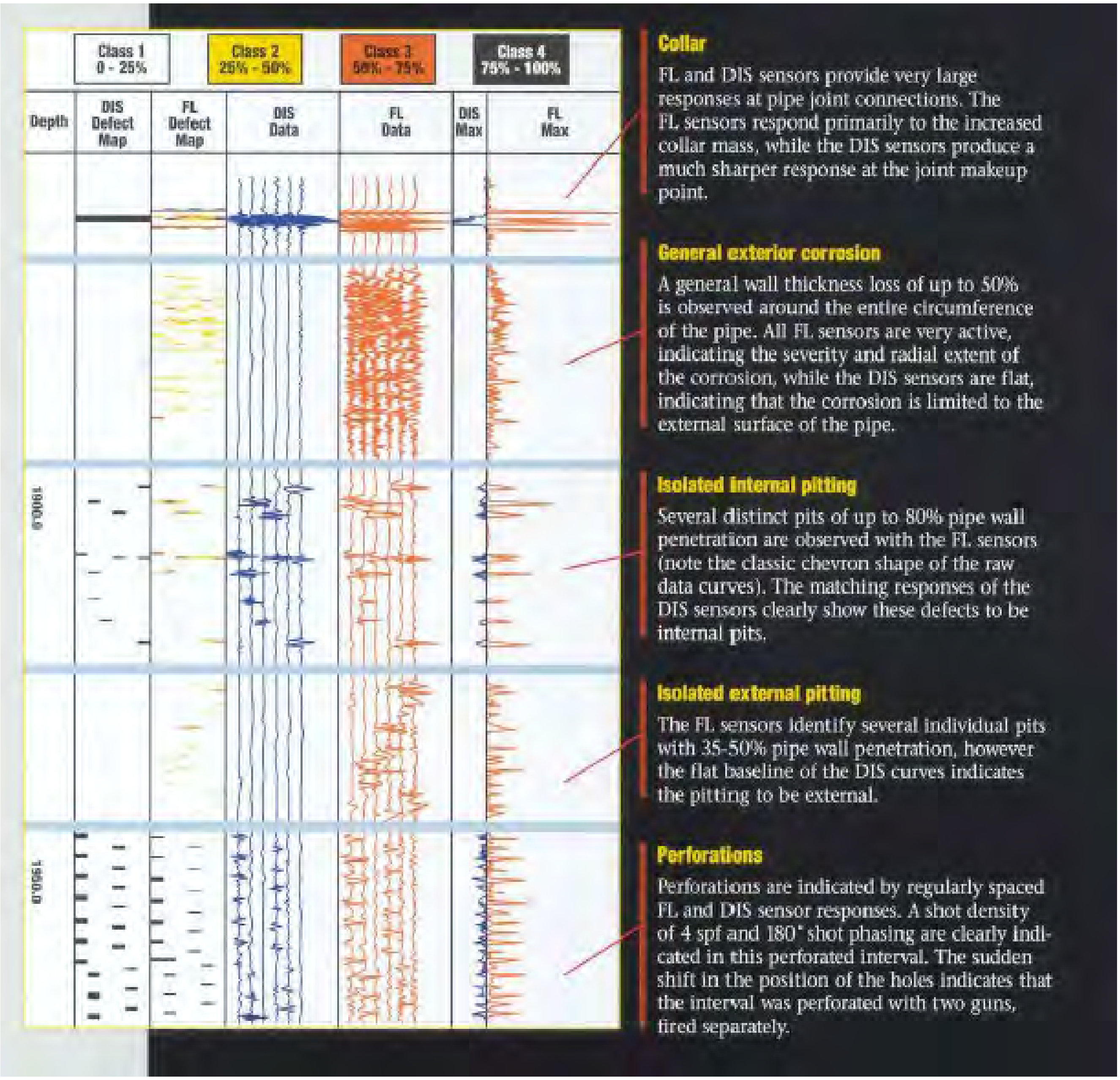
Periodically, E-Log-I surveys to be conducted by CD in an attempt to ensure that sufficient bond current is being applied to each well's production casing string.

3. Casing Inspection Logging using Electromagnetic Logs:

This tool (electromagnetic corrosion and protection evaluation log) measures the casing potential and resistance evaluation, thereby determining the extent of the corrosion. The electromagnetic log used by the RE is the Vertilog or equivalent technology provided by other vendors. "The Vertilog is a casing inspection service which is now available to the oil and gas industry to determine the condition of the casing in existing wells. It is a quantitative measurement of corrosive damage, indicating if the metal loss is internal or external and if it is isolated or circumferential", (onepetro.org). **NOTE: Usage of term Vertilog does not indicate strict usage of Baker-Hughes named tool "Vertilog". It is used in this document as a common term in the use of magnetic flux leakage technology.**

Casing Inspection Logging and Data Assessments

Figure 1 Detailed Vertilog courtesy of Baker-Hughes.



Casing Inspection Logging and Data Assessments

Figure 2 TC-17 2014 Vertilog

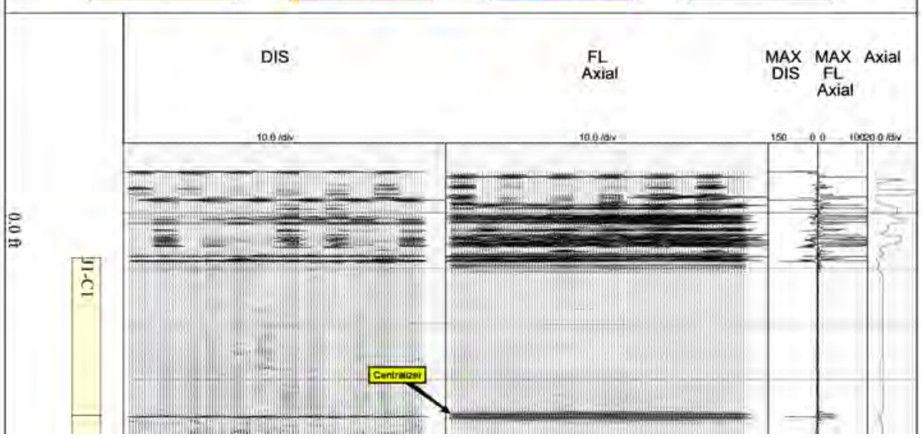
Shows the Vertilog of well TC-17N during the 2014 Rework program courtesy, Baker Hughes.

97	4025.71	4068.04	42.33	Class 1	-	-	-
98	4068.04	4108.20	40.16	Class 1	-	-	-
99	4108.20	4150.37	42.17	Class 1	-	-	-
100	4150.37	4191.30	40.93	Class 1	-	-	-
101	4191.30	4231.99	40.69	Class 1	-	-	-
102	4231.99	4274.78	42.79	Class 1	-	-	-
103	4274.78	4316.70	41.92	Class 1	-	-	-
104	4316.70	4358.62	41.92	Class 1	-	-	-
105	4358.62	4399.68	41.06	Class 1	-	-	-
106	4399.68	4440.89	41.21	Class 1	-	-	-
107	4440.89	4482.02	41.13	Class 1	-	-	-
108	4482.02	4524.22	42.20	Class 1	-	-	-
109	4524.22	4565.84	41.62	Class 1	-	-	-
110	4565.84	4607.83	41.99	Class 1	-	-	-
111	4607.83	4650.42	42.59	Class 1	-	-	-
112	4650.42	4691.58	41.16	Class 1	-	-	-
113	4691.58	4736.63	45.05	Class 1	-	-	-
114	4736.63	4781.57	44.94	Class 1	-	-	-
115	4781.57	4826.04	44.47	Class 1	-	-	-
116	4826.04	4870.57	44.53	Class 1	-	-	-
117	4870.57	4913.80	43.23	Class 1	-	-	-
118	4913.80	4959.82	46.02	Class 1	-	-	-
119	4959.82	5004.14	44.32	Class 1	-	-	-

Pacific Gas & Electric Turner Cut-17N
File 20140821_232049_RSP_0_0_0_0.mvl

Main Log
5"/100'

Class 1	Class 2	Class 3	Class 4
0 - 20%	20 - 40%	40 - 60%	60 - 100%



Casing Inspection Logging and Data Assessments

4. **Vertilog Class/color identification:**

   The following class/color identification is based on the Baker-Hughes Vertilog correlation analysis whose penetration involves the acquired flux change, discriminator sensor management and the computed results.

   - Class 1: Seen in white, includes 0-20% penetration
   - Class 2: Seen in orange, includes a 20-40% penetration rate
   - Class 3: Seen in pink, includes a 40-60% penetration
   - Class 4: Seen in black, includes a 60-100% penetration.

5. **Evaluation (RE steps):**

   5.1. Evaluate The survey logs to determine if any apparent anomalies exist.

   5.2. Review logs when they arrive in office. Check for large defects that should be addressed immediately, confirm log header information and casing information is correct, confirm that all logs run have been received.

   5.3. Perform quality review of log and data for missing scales and well information.

   5.4. Verify log and other feature depths match wellbore schematic or other logs.

   5.5. Use previously run log as base line and compare and correlate the apparent anomalies to identify potential casing integrity issues.

   5.6. Report any anomalies or features or trending immediately to the director, manager, supervisor and engineer.

   - Consider investigations presented in Procedure B, Additional Investigations.
   - Procedure C, Casing Inspection Survey Frequency Decision Tree lists definitions for metal loss and assessment of apparent growth
   - Use Standard D, Remedial Options and Decision Tree provides a process diagram to aid in the development of a plan of action to assess the anomalies. Determine remedial action Based on the plan of action results. The well will remain shut in until repairs are completed or the well will be placed back in service. All plan of action documentation will be kept in the GSDB/well file.

   5.7. Prepare a summary report (one report per field) documenting results.

Casing Inspection Logging and Data Assessments

5.8. Select wells for next year's logging program based on a specific recommendation that had been made at the time of the previous review, or according to the "Casing Inspection Survey Frequency Decision Tree".

5.9. Prioritize remedial work based on the above, and input in the GSDB.

5.10. Communicate results to GPOM and GSAM.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, GSAM

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

Standard 9, Mechanical Integrity of Wells, Appendix 1 Well Logging Criteria for New, Redrilled and Reworked Wells

Procedure Z, Well Integrity Testing Regime Process

APPENDICES

n/a

Casing Inspection Logging and Data Assessments

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix S15 in Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix S15 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Temperature / Noise Logging and Data Review

SUMMARY

Purpose: Provide standards and procedures for temperature / noise logging and data review. See the Reference Document section near the end of this procedure. This procedure provides some requirements for surveys that gather data and addresses the assessment of the data obtained from the surveys. The companion procedure TD-4870P-01 Gas Well Wireline Procedure addresses the process to connect to well, the running of the tool in the well and collecting the data during the running.

What: This is to comply with the CalGEM regulations (California Code of Regulations Title 14, Division 2, Chapter 4) for annual well casing integrity survey. permitting requirements, and in general to investigate a well's integrity. .

Why: The testing is conducted on an annual frequency to comply with the State CalGEM regulation requirements that a mechanical integrity test (MIT) must be performed on all injection wells annually (CalGEM 1926.6 a1) to ensure the injected fluid is confined to the approved zone or zones.

When: Tested annually normally between April and October of the year. May be required based on a permit condition, or to investigate well integrity.

NOTE: Logs must be submitted to CalGEM within 30 days after being run in a well.

NOTE: Notify CalGEM at least 48 hours in advance of running the log survey per California PRC 1726.6(d).

Target Audience

Gas Pipeline Operations and Maintenance (GPOM) initiates clearances.

Contractor performs testing services.

Gas Storage Asset Management (GSAM) - Reservoir Engineering (RE)

- supervises on-site surveys.
- reviews survey data for reasonableness and completeness.
- evaluates survey data and recommends course of actions, if any.

Temperature / Noise Logging and Data Review

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SUBSECTION TITLE PAGE

1. Noise-Temperature Survey Program

   Engineer – prepares a noise temperature survey program and provides to Project Management for review, scheduling and implementation of the program. Engineer to provide priority to complete program and any deadlines.

   1.1. RE: will prepare a written noise-temperature survey program that supports ensuring that specific noise-temperature survey requirements and instructions for surveying gas storage wells are understood by PG&E employees and contractors who are involved in conducting noise-temperature survey operations before, during, and after the survey operations are completed. The following should be prepared and be included with the program.

   - Wireline Call-out Sheet
   - Wellbore Schematic

   1.2. Wireline Call-Out Sheets: Include depths to investigate, such as depth intervals between readings such as from the bottom of tubing, in the vicinity of suspected leak areas, and relative to surface. and logging speed in the well specific program created. Consider recommendation from the logging vendor.

   1.3. RE and the contractor: Reach agreement on the proper depths and times at which readings will be taken in the acoustic/noise logging process.

   1.4. RE: Notify GalGEM at least 48 hours in advance of running the log survey per California PRC 1726.6(d). Confirm in writing the date and time that DOGGR was notified and when they acknowledged the notification prior to commencing the log survey

   1.5. RE: File notifications and CalGEM acknowledgement in the CalGEM notification folder on the GSAM “G” drive.

Temperature / Noise Logging and Data Review

1.6. RE/GPOM: Inspect the progress of the logging for quality and conformance to plan.

2. RE Evaluation Steps

2.1. Perform quality review of log and data for missing scales and well information

2.2. Verify log and other feature depths match wellbore schematic or other logs

2.3. Evaluate the survey logs to determine if any apparent anomalies or features exist. This includes confirming that the well log header is complete (well name, depth, date and any other q/c information that is needed).

2.4. Document the results of the review in the wireline database.

2.5. Compare the apparent anomalies to the previous year survey results to determine the severity of the apparent anomalies.

2.6. Correlate the apparent anomalies with the gamma ray neutron logs (CCR 1726.7(b)(2)(D)) and the casing inspection results to identify casing integrity issues.

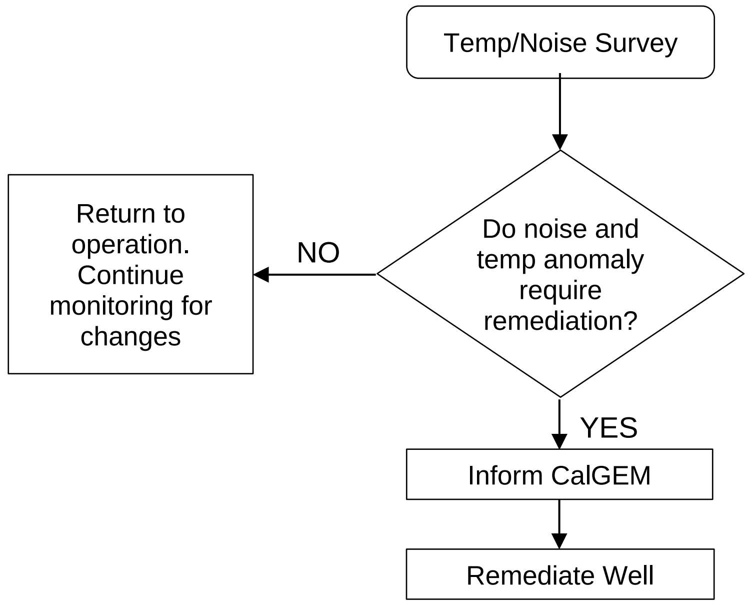
2.7. Communicate the results to CalGEM and the Director of GSAM within 30 days of running the log.

NOTE: Logs must be submitted by Reservoir Engineering to CalGEM within 30 days after being run in a well.

2.8. Prioritize remedial work based on the above and input in the gas storage database (GSDB) and investment planning processes.

The following flow chart depicts the procedure addressed above.

Figure 1. Temp/Noise Survey Decision Tree.



END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEM regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, GSAM RE

GOVERNING DOCUMENT

GSAM Standard 1
GSAM Standard 9 – Mechanical Integrity of Wells

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Temperature / Noise Logging and Data Review

Supplemental References:

Detailed Procedure: Utility Procedure: TD-4870P-01 Gas Well Wireline Procedure (Replaced TD-4550P-20)

APPENDICES

Equipment and Process Overview

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix T16 in the Underground Storage Risk and Integrity Management Plan, 7/10/20 rev 6a.

Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix T16 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Temperature / Noise Logging and Data Review

APPENDIX – Equipment and Process Overview

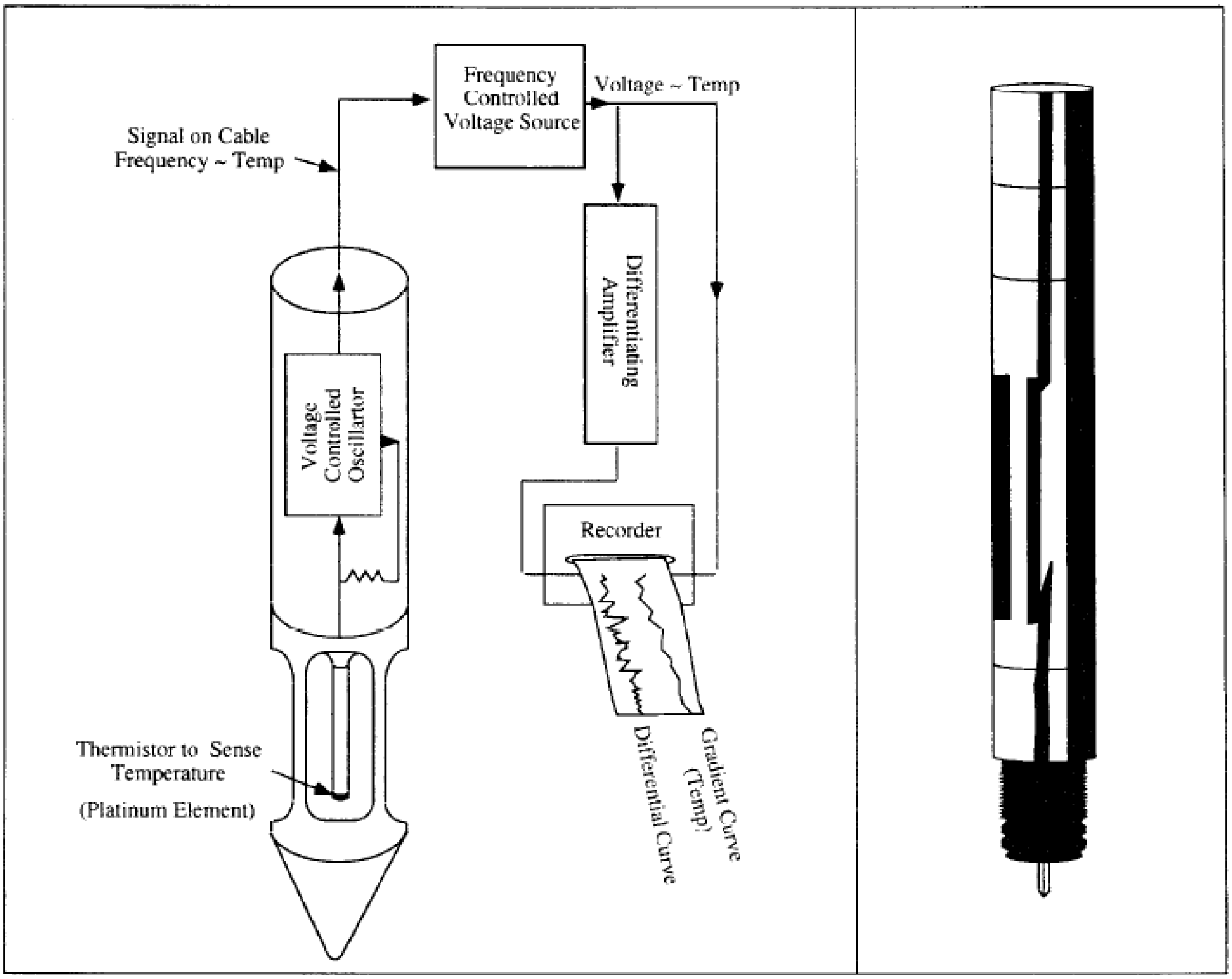
As mentioned earlier, PG&E's temp/noise survey are usually contracted out. Figure 4. shows a temp/noise survey in progress at the Whiskey Slough station.

Figure 4. Temp/noise survey in progress on the Whiskey Slough station.

Temperature / Noise Logging and Data Review

The survey is usually conducted on an analog/digital truck contracted by PG&E which transmits a count per minute which is converted to voltage by a counting circle and recorded. Figure 1 (A&B) below shows an overview of the temp/acoustic tool.

Figure 1. Temp/Acoustic Tool.

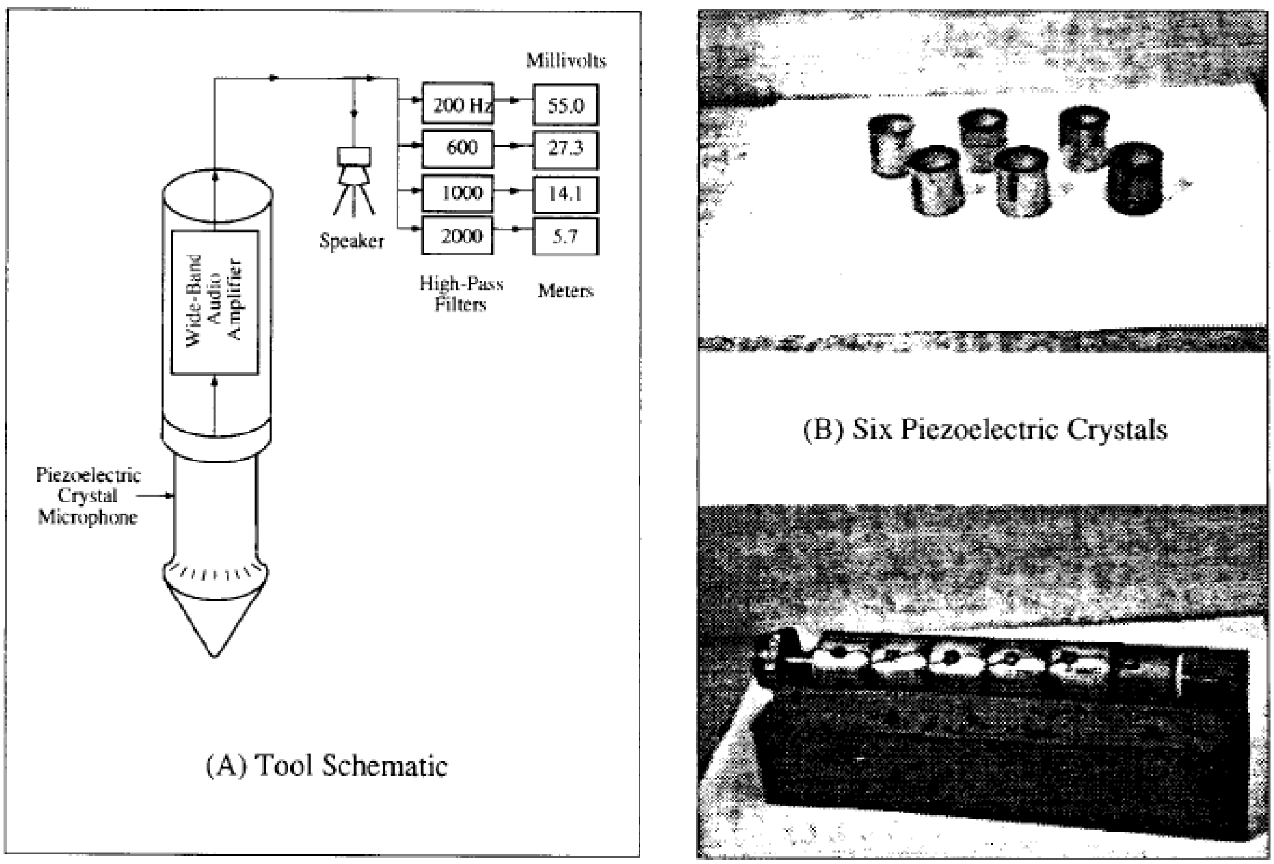


(A) Schematic of Tool (B) Actual Tool

Temperature / Noise Logging and Data Review

A noise logging tool is a microphone designed to handle wellbore conditions and measures sound at different positions in the borehole. Figure 2 (A&B), Shows a schematic of an acoustic tool and piezoelectric crystals which converts the oscillating pressure associated with sound transmission within the wellbore to an oscillating voltage that input directly to an amplifier-cable driver combination.

Figure 2. Acoustic/Noise Tool Schematic and Piezoelectric Crystals



(A) Tool Schematic

(B) Six Piezoelectric Crystals

Gamma Ray Neutron Logging

SUMMARY

Purpose: Provide standards and procedures for gamma ray neutron (GRN) logging and data review.

What: The GRN logging or equivalent is supplemental to the Noise/Temperature (N/T) logging to ensure compliance with CalGEM regulations for annual well casing integrity monitoring (CCR 1726.7(b)(2)(D). The GRN log can be run in air, oil, gas or mud filled open or cased holes. The basic neutron logging tools each consisting of a chemical neutron source.

- RST: Reservoir Saturation Tool
- CNL: Compensated Neutron Log
- SNL: Sidewall Epithermal Neutron Log
- GRN: Gamma Ray Neutron Log

The GRN logs are one of the three classes of the neutron logging tool. The GRN is sensitive to capturing gamma rays that are emitted due to the absorption of thermal neutrons by the nuclei in the rocks

Principle of Operation:

- Neutrons emitted from radioactive source
- Collide and lose energy (Billiard ball effect)
- Primarily dependent on hydrogen concentration or index
- Detect either epithermal neutrons, thermal neutrons, capture gamma rays or combination
- Thus, measures the formations ability to attenuate the passage of neutrons

Why: The GRN logging or equivalent (the other three in the list above) is supplemental to the N/T logging to provide additional correlations in evaluating casing integrity, to improve well casing integrity and safety, reduce the risk of gas leakage and unsafe operations. Also, the GRNL is unaffected by fluids and measures both the lithology and natural radioactivity of the formation using a scintilometer (Geiger counter). GRNL can also be useful for the following:

- Determination of porosity / Lithology
- Delineation of porous formations
- Gas detection (with other logs)
- Estimation of shale content (w/ other logs)

Gamma Ray Neutron Logging

When: Baselines have been established. Surveys should be re-run based on well performance, or when a well's integrity is reassessed. Issues that affect rescheduling include anomalies found or re-entry schedules.

NOTE: Logs must be submitted to CalGEM within 30 days after being run in a well.

NOTE: NOTIFY CALGEM AT LEAST 48 HOURS IN ADVANCE OF RUNNING THE LOG SURVEY PER CALIFORNIA PRC 1726.6(D).TARGET AUDIENCE

Gas Pipeline Operations and Maintenance (GPOM) initiates clearances

Contractor performs testing services.

Gas Storage Asset Management (GSAM) - Reservoir Engineering group (RE)

- supervises on-site surveys
- reviews survey data for reasonableness and completeness.
- evaluates survey data and recommends course of actions, if any.

TABLE OF CONTENTS

Gamma Ray Neutron Logging

1. RE Evaluation Steps

1.1. Perform quality review of log and data for missing scales and well information. If any quality issues, contact vendor for correcting.

1.2. Verify log and other feature depths match wellbore schematic or other logs.

1.3. Evaluate the survey logs to determine if any apparent anomalies exist.

1.4. Use baseline GRN or equivalent log if one has been established as base line and compare the apparent anomalies to determine the severity of the apparent anomalies and identify gas migration, if any.

1.5. Correlate the apparent anomalies with the N/T logs and the Casing Inspection results to identify casing integrity issues.

2. Publish/Communicate

Communicate the results to the Reservoir Engineering Department.

3. Prioritize and Propose Work

RE: Prioritize remedial work based on the above, and input in the GSDB and investment planning processes

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, RE, GSAM

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in standard 1, Section 3.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

Detailed Procedure: Utility Procedure: TD-4870P-01 Gas Well Wireline Procedure (Replaced TD-4550P-20)

APPENDICES

Tools

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix U17 in the Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Allan Lee, Manager, RE Integrity Management, GSAM

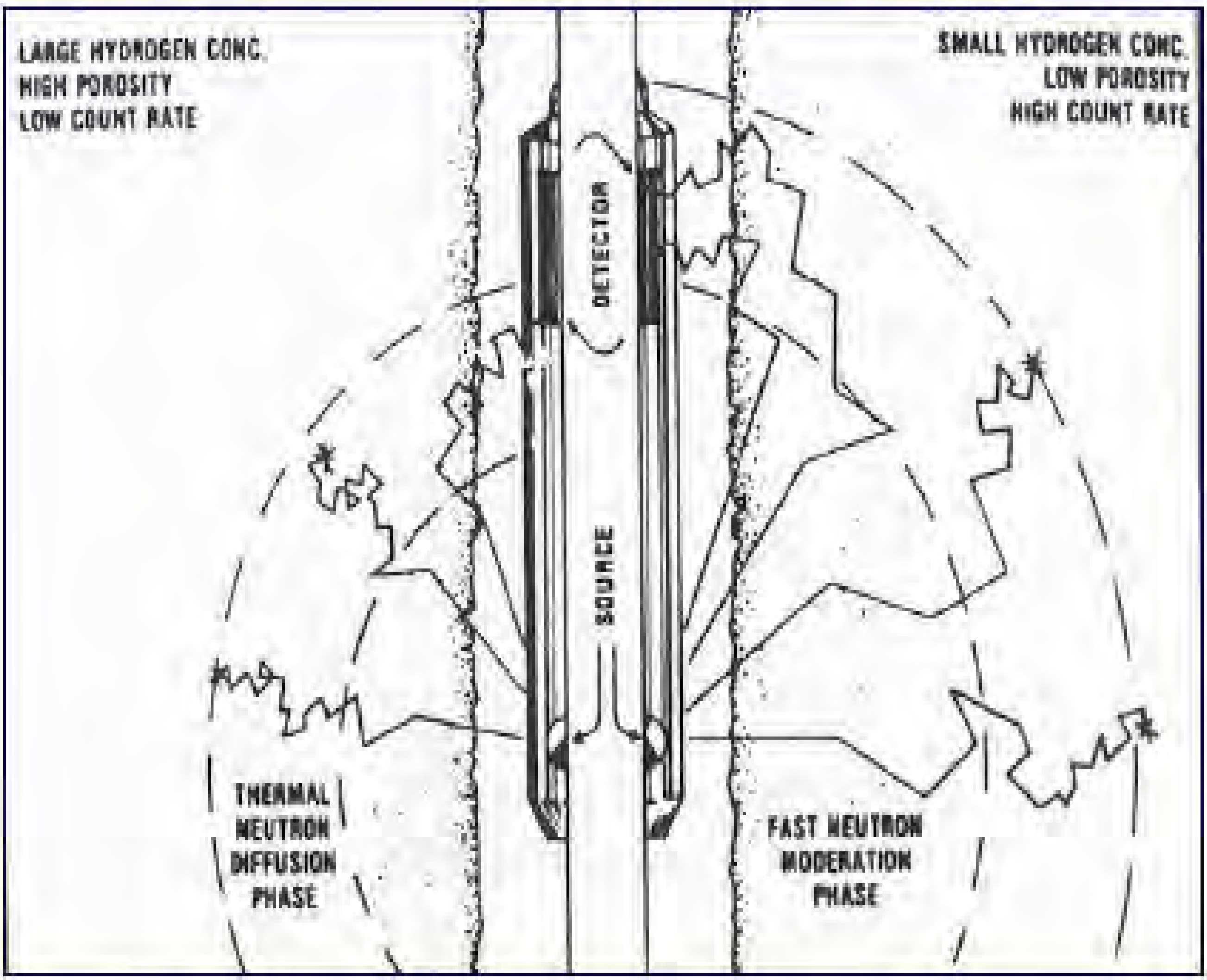
REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix U17 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Gamma Ray Neutron Logging

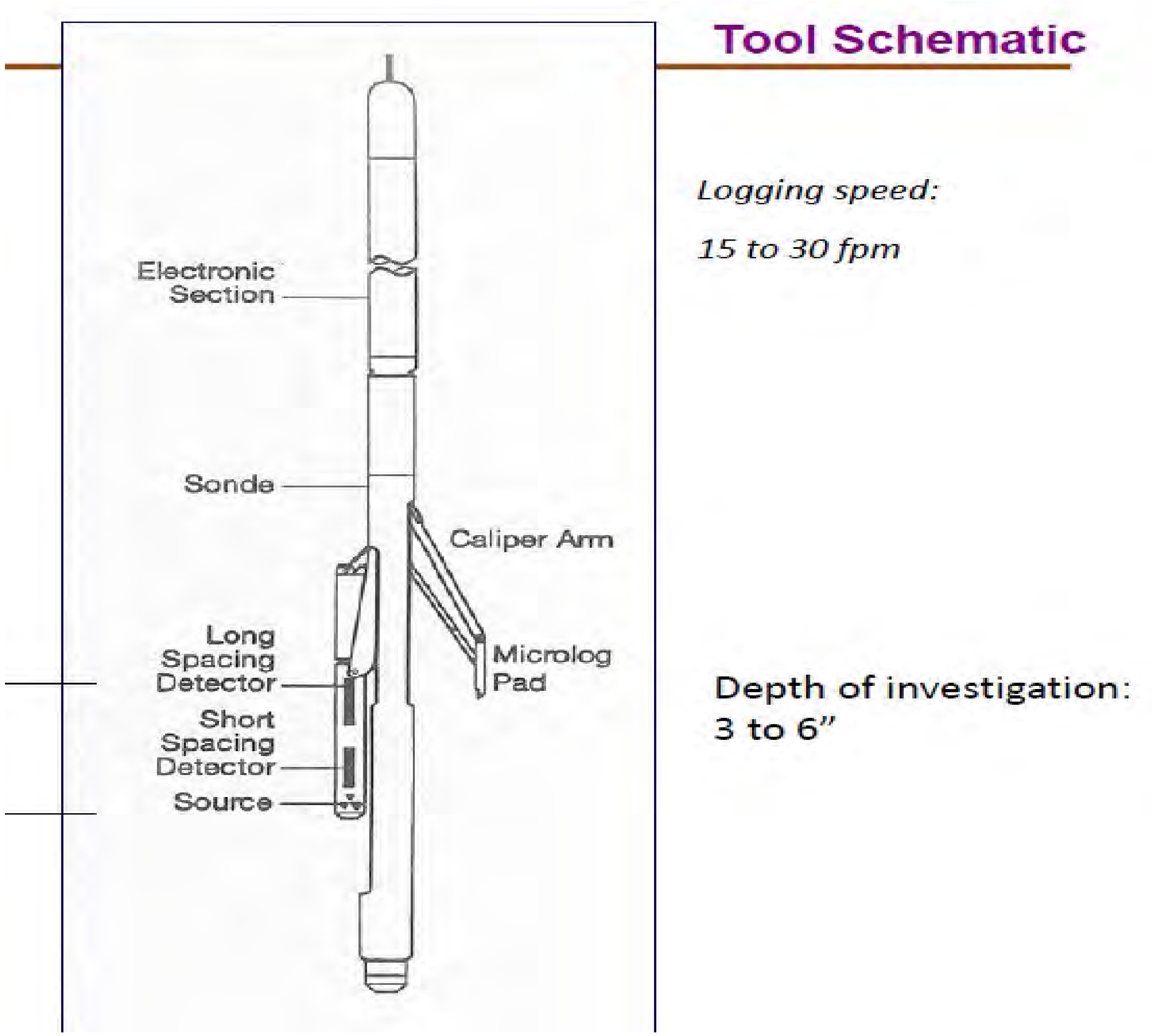
APPENDIX 1 – Tools

Figure 1. Single Neutron Tool In a Bore-Hole.



Gamma Ray Neutron Logging

Figure 2. Density Logging Tool Schematic.



Cement Bond Logging Survey

SUMMARY

Purpose: Provide standards and procedures for cement bond logging survey.

What: The cement bond log (CBL) or equivalent such as RBL (Radial Bond Log) is supplemental to other mechanical integrity assessments to ensure compliance with CalGEMs regulations for well casing integrity monitoring and well construction (CCR 1726.5). Cement bond tools measure the bond between casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using an acoustic sonic (noise/temp) and ultrasonic tools.

Why: The CBL is performed to:

1. Evaluate integrity of cement sheath in the annulus between casing and formation.

2. Identify the top of cement (TOC) for potential gas migration paths, if leaks are detected. It is also for additional correlations to improve well casing integrity and safety and reduce the risk of gas leakage and unsafe operations.

When: Log is run to establish baseline, meet a permit requirement, or to investigate well integrity. Note: Normally CBL (or equivalent) is run right after the production casing is cemented in place. In some case, it is re-run to verify integrity and TOC and for correlation purposes if leaks behind casing are suspected. The only opportunity to re-run the CBL is during well rework because during rework the tubing is out of the hole and allow CBL tool to be run in the well.

NOTE: Logs must be submitted to CalGEMs within 30 days after being run in a well.

NOTE: Notify CalGEM at least 48 hours in advance of running the log survey per California PRC 1726.6(d).

Who:

Gas Pipeline Operations and Maintenance (GPOM) initiates clearances

Contractor performs logging/testing services.

Gas Storage Asset Management (GSAM), Reservoir Engineering (RE)

- supervises on-site surveys.
- reviews survey data for reasonableness and completeness.
- evaluates survey data and recommends course of actions, if any.

- perform quality review of log and data for missing scales and well information.
- verify log and other feature depths match wellbore schematic or other logs.
- submits logs to CalGEM within 30 days after survey is run in a well.

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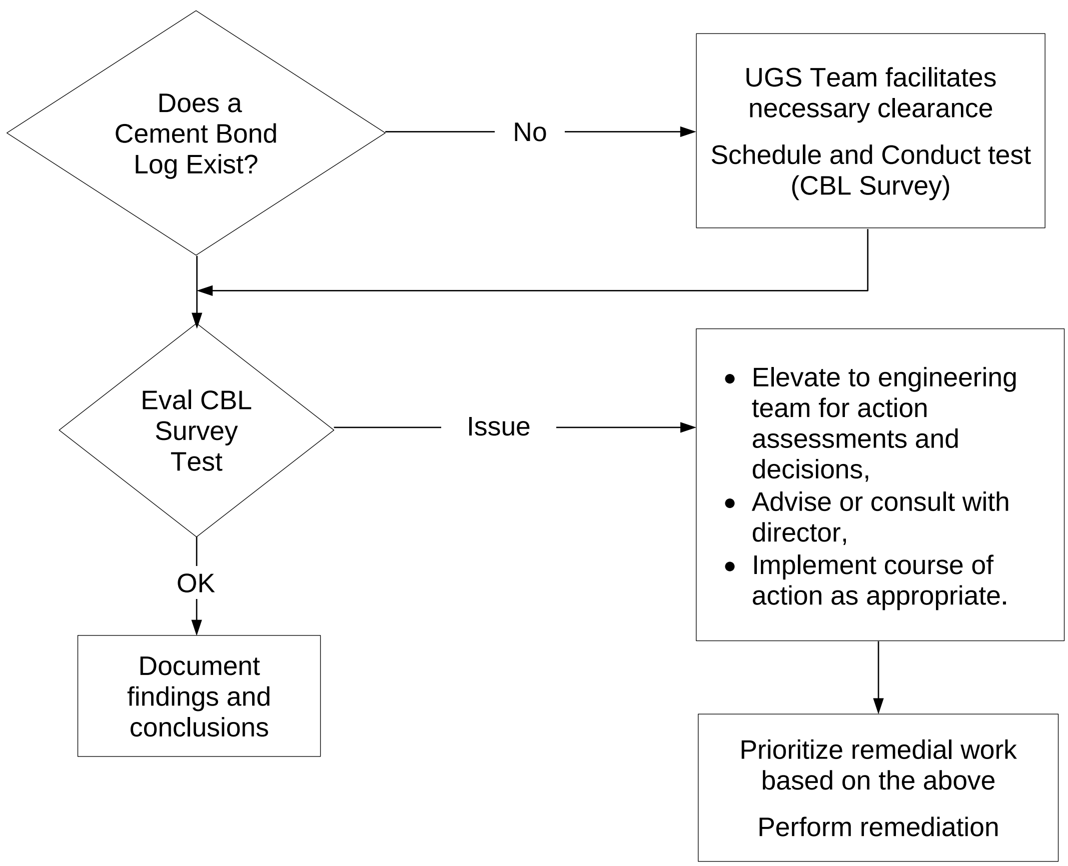
SUBSECTION TITLE PAGE

Cement Bond Logging Survey

1. Well Integrity Evaluation and Communication:

Note: CBL is one of the components for evaluating/monitoring gas leaks and/or gas migration. For complete evaluation/analysis, it needs to correlate with other logs (T/N, GRN, Vertilog, IE logs, etc.).

Figure V-2. Cement Bond Logging Decision Tree.



1.1. Determine if a CBL exists for the well. If not, then schedule and run a CBL for the well.

1.1.1. Evaluate and correlate apparent anomalies with the all the integrity survey (CBL, T/N, GRN, and Vertilog) results and determine how to approach the next step if there are apparent cement sheath integrity issues which contribute to gas migration.

1.2. CBL Evaluation:

Perform quality review of log and data for missing scales and well information. If any quality issues, contact vendor for correcting.

Verify log and other feature depths match wellbore schematic or other logs.

Review and evaluate the CBL survey logs to verify cement sheath bonding in the annulus between casing and formation.

Identify top of cement (TOC) and other areas that have cement bonding issues, and denote such on the well schematics for references.

1.3. If the evaluation identifies issues to be addressed, escalate to Director, GSAM to review and confirm proposed courses of action.

1.4. Prioritize remedial work based on the above, update rework prioritization spreadsheet, and input in the GSDB and investment planning processes.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

n/a

APPENDICES

CBL Technology

Cement Bond Logging Survey

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix V18 in the GSAM Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

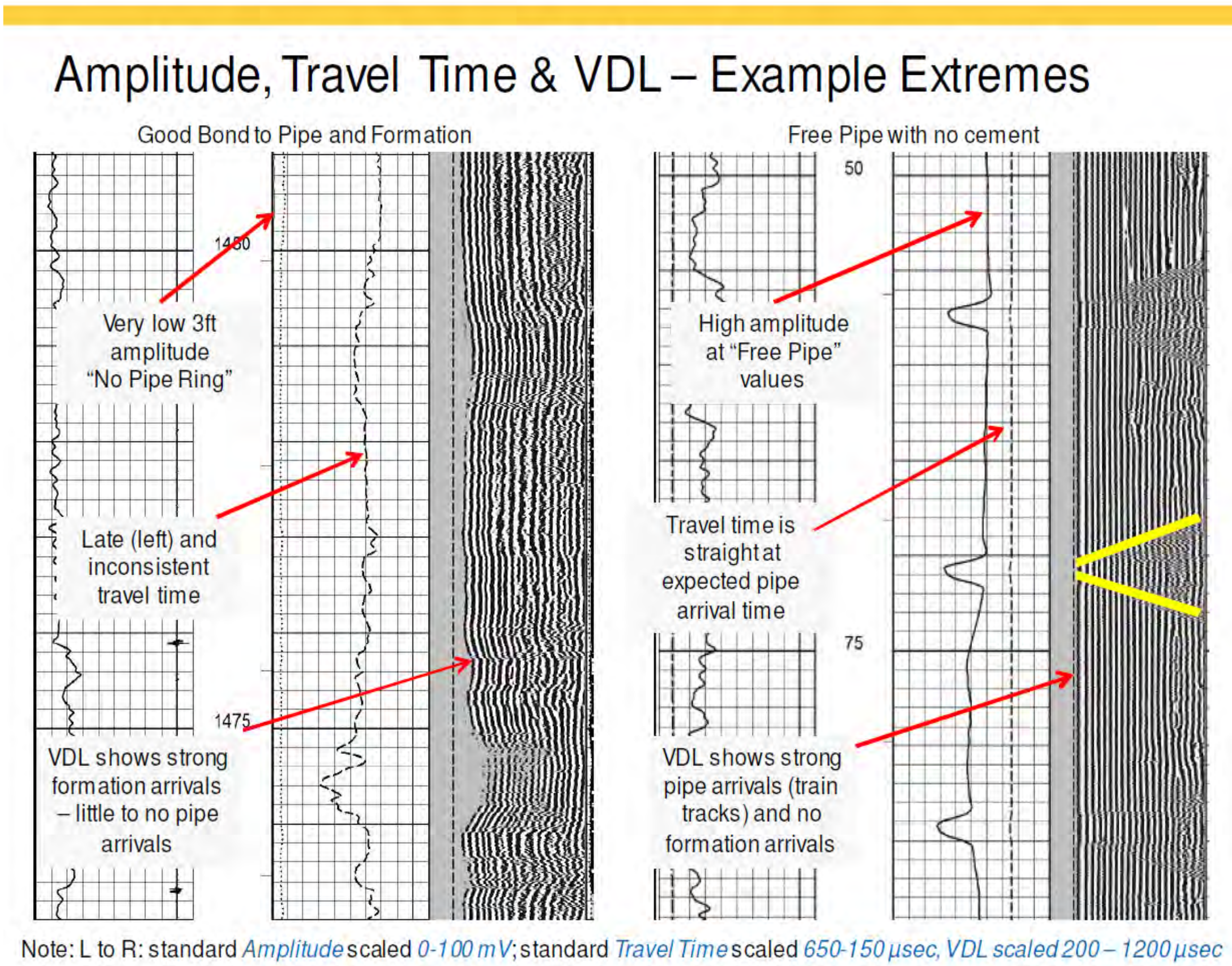
Where?	What Changed?
Converted RIMP Appendix V18 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Cement Bond Logging Survey

APPENDIX 1 – CBL Technology

- CBL utilizes the amplitude of sonic sound signal to determine bonding integrity between casing and formation.
- The tighter the bonding between the casing and formation, the less amplitude showing on the log. It is like ringing a bell and it is loud (high amplitude). The ringing bell is not as loud (low amplitude) by putting a hand on it.
- See example in Figure 1 below for comparison between good bonding and no bonding.

Figure 1. Amplitude, Travel Time and VDL – Example Extremes.



Well Integrity Testing Regime Process – Production Casing

SUMMARY

This procedure sets forth the testing regime process that PG&E utilizes for performing and assessing well integrity and subsequent reassessments during well entry operations.

TARGET AUDIENCE

Gas Storage Asset Family (GSAM).

Gas Pipeline Operations and Maintenance (GPOM) staff (for information).

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REQUIREMENTS

1 Testing Regime Process Flow Chart

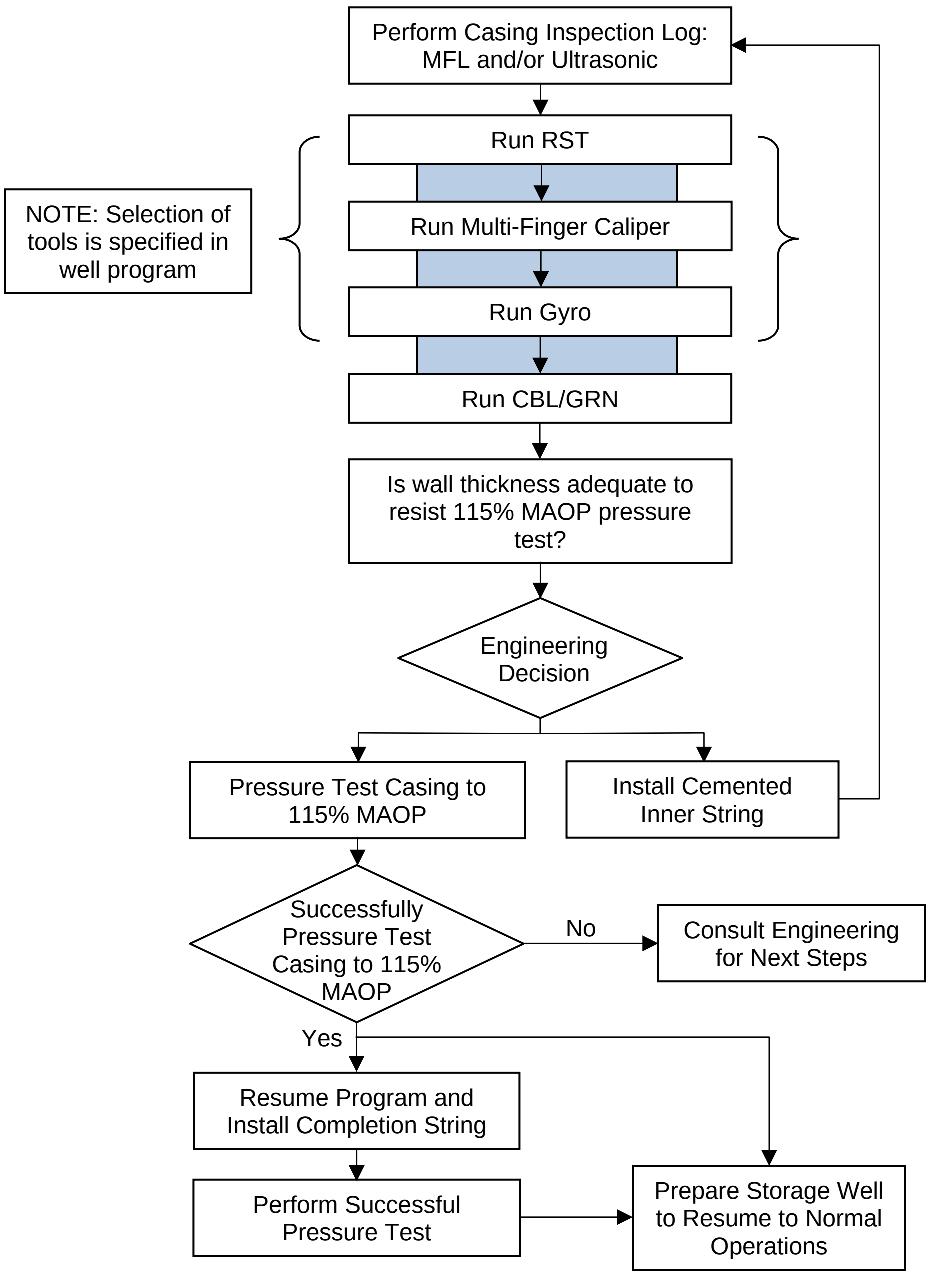
The following flow chart illustrates the testing regime process that PG&E utilizes for performing and assessing well integrity during rework operations where a full assessment is performed. Reassessment frequency is guided by Standard D, Procedures B, C, K and S for remedial options, Standard 9, and Standard 10 Section 1.

1. RE will periodically review the testing regime process flow chart to determine need for modifications to the testing regime
2. Review will include the following:
    a. Logging technology applicability
    b. Vendor and tool performance
        i. quality review of log and data for missing scales and well information
        ii. changes in depths match on wellbore schematic or other logs
    c. Frequency of inspection changes
    d. Changes in regulatory requirements

e. Changes to company standards or procedures that may require revision

3. RE will prepare report of review and report to director

Figure 1 – Well Integrity Testing Regime Process



END of Requirements

Well Integrity Testing Regime Process – Production Casing

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, GSAM

GOVERNING DOCUMENT

GSAM Standard 1

Standard 9, Mechanical Integrity of Wells

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

Procedures B, C, K and S for remedial options, Standard 9 and D, and Standard 10 Section 1

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Well Integrity Testing Regime Process – Production Casing

Document Contact

Larry Kennedy, Strategic Planning Chief, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix Z to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Safety Valve Operation, Maintenance and Inspection

SUMMARY

This standard addresses well safety valve operation, maintenance and inspection.,

NOTE: Notify CalGEM at least 48 hours before performing function testing so they may witness the operations

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

Safety:

Safety issues are addressed in each of the procedures referenced in the requirements below.

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SUBSECTION TITLE PAGE

Safety Valve Operation, Maintenance and Inspection

REQUIREMENTS

1. Background

PG&E's storage fields are equipped with safety valve systems to isolate the various assets as part of the emergency shutdown systems. Storage wells and the connecting piping should be risk assessed on the need to provide isolation during an emergency. The cause of these emergencies could be the integrity failure of a well or pipeline, runaway trucks, explosions, outside natural forces, vandalism/terrorism, or other nearby construction activities.

Wells equipped with a "downhole" safety valve (DHSV) or surface controlled subsurface safety valves (SCSSV) typically have valves installed 250 feet below ground level to provide emergency shutdown in the event the storage well cannot be isolated by the wellhead master valve. DHSV valves are surface controlled, hydraulically operated and are "fail safe" type valves (hydraulic control system pressure keeps the valves open, and the valves close on loss of hydraulic control system pressure).

"Uphole" safety valves (UHSV) or emergency shutdown valves (ESD) are installed to isolate the transmission pipeline from abnormal low pressure downstream of the valve, including loss of containment of a storage well or the piping systems.

Safety valve systems are maintained in accordance with Utility Standard: TD-4521S Gas Valve Maintenance Standard and by personnel who have received training in preventative and mitigated activities (typically referred to as maintenance) under PG&E's operator qualification (OQ) program. Contract personnel (such as downhole safety valve manufacturer) engaged to perform preventative and corrective maintenance on this equipment accordingly are trained by the manufacturer or must demonstrate training. Refer to Procedure AH, Well Work Contractor Competency for further information.

Valves are designed to withstand the maximum operational pressures (CCR 1726.8 (d)) pursuant to Procedure E1A, Wellhead Equipment Design Standard.

2. Applicable Codes

CFR 192.12 – incorporated API RP 1171, Section 6.2.5 Emergency Shutdown Valves, Section 9.3.2 function testing practice for surface and surface safety valve systems.

CCR, Title 14, Chapter 4, Subpart 1, Article 3; 1726.8 - Inspection, Testing, and Maintenance of Wellheads and Valves, Section (a) and 1726.3(d)(1) – Risk Management Plan. API RP 14B – Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems referenced by PHMSA and DOGGR

3. Testing / Inspection

Function tests shall be performed on uphole and downhole safety valve systems once every 6 months (CCR 1726.8(a)). See TD Utility Standard: TD-4521S , Gas Valve Maintenance Standard.

Leak-by tests shall be performed on uphole and downhole safety valves once every 6 months, see TD Utility Standard TD-4521S, Gas Valve Maintenance Standard.

3.1. Testing Notification

GPOM shall notify CalGEM at least 48 hours before performing function testing so they may witness the operations (CCR 1726.8(a)). Documentation of the testing shall be maintained and available for CalGEM review.

Results of the Leak-by testing shall be reviewed by GSAM personnel (Procedure R14 – Evaluation of Safety Valves (DHSV) Leak by Testing.)

Within 90 days of finding that a safety valve is inoperable, the PG&E shall repair the valve or temporarily plug the well (CCR 1726.8(a)).

4. Operations

API 1171 requirement 9.3.2 and CCR 1726.8(a), ”a closed storage well safety valve system shall be manually re-opened at the site of the valve after an inspection and not opened from a remote location” is interpreted by PG&E as the following:

- To apply to situations where the safety valve trips and must be reset, and not to routine testing of safety valves addressed in the Testing / Inspection section above.
- To allow re-opening of the valve from the valve site or the control room or any intermediate location, provided that the reason for the trip has been investigated and the safety of re-opening has been confirmed.

Specific requirements for operation of safety valves in the event of a trip or abnormal operating condition reside in the operating procedures developed and maintained by GPOM and RE for each storage field.

5. Records

Safety valve testing, maintenance and repair records are created by GPOM, and are maintained on the GPOM hardcopy records systems.

Records involving repairs conducted by third party service providers that are developed as part of project work are maintained in GSAM's shared drive in a folder associated with that asset and that project.

Maintenance records that change as a result of the project are updated and maintained by GPOM.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Gas Storage Asset Management integrity management engineers – Policy for and execution of this standard.

Gas Pipeline Operations and Maintenance personnel – Storage facility maintenance and operations

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

GSAM Procedure AH, Well Work Contractor Competency

GSAM Procedure R14, Evaluation of Safety Valve Leak-by Testing

APPENDICES

n/a

Safety Valve Operation, Maintenance and Inspection

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 11 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 11 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Wellhead (Christmas Tree) Valve Operation, Maintenance and Inspection

SUMMARY

This standard addresses storage wellhead valve operation, maintenance and inspection.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)
GPOM

SAFETY

Safety issues are addressed in each of the procedures referenced in the requirements below and in site guidance documents.

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REQUIREMENTS

1. Background

On PG&E's storage field wells, a Christmas tree, or "tree", is an assembly of valves, spools, and fittings mounted a the top of the well casing and tubing, used to regulate the flow to and from each gas storage well.

Valves are designed to withstand the maximum operational pressures (CCR 1726.8 (d))pursuant to Standard E1A, Wellhead Equipment Design.

Wellhead (Christmas Tree) Valve Operation, Maintenance and Inspection

Storage wellhead (Christmas tree) valves must be maintained in order to ensure that they can be operated as intended to shut off gas flow or isolate a well in the event of an emergency or for routine maintenance (CCR 1726.8(c)).

Storage well heads (Christmas tree) and the connecting piping should be risk assessed on the need to provide isolation during an event. The cause of these events could arise as from the integrity failure of a well or pipeline, runaway trucks, explosions, outside natural forces, vandalism/terrorism, or other nearby construction activities.

Wellhead valves are maintained in accordance with Utility Standard TD-4521S Gas Valve Maintenance Standard and by personnel who have received training in preventative and mitigated activities (typically referred to as maintenance) under PG&E's operator qualification (OQ) program. Contract personnel (such as wellhead valve manufacturer) engaged to perform preventative and corrective maintenance on this equipment accordingly are trained by the manufacturer or must demonstrate training (CCR 1726.8(b)).

Inspections, monitoring, and reporting for the unintended surface or cellar gas releases are conducted utilizing ambient area monitoring and inspection of the wellhead and cellar (CCR 1726.7(f) and 1726.9) and PG&E’s California Air Resources Approved Monitoring Plans approved by California Air Resources Board listed below..

2. Applicable Codes and Guidance Documents

Valve operation, maintenance and inspection in addition are governed by this section and the companion documents listed in the Reference Documents section further below in this standard.

3. Testing

Function tests shall be performed at least once each calendar year (CCR 1726.8(b)) not to exceed 15 months pursuant to Utility Standard TD-4521S, Gas Valve Maintenance Standard.

Monitoring of wellhead pressures are conducted according to Procedure J6, Wellhead Pressure Monitoring and conduct quarterly. If any well is not accessible, for reasons such as well is being serviced or not to be operated for safety reasons, RE should document the reason on the well pressure forms.

4. Inspection

Inspection: Routine and preventative maintenance tasks should be conducted in accordance to Utility Standard: TD-4521S Gas Valve Maintenance Standard

Wellhead (Christmas Tree) Valve Operation, Maintenance and Inspection

5. Records

Valve testing, maintenance and repair records are created by GPOM, and are maintained on the GPOM hardcopy records systems and/or SAP, as applicable.

GPOM should inform GSAM engineering of any wellhead valve that fails to pass inspection and testing immediately.

Monitoring pressure records are maintained by GSAM.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM integrity management engineers

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References: Procedures referenced in the requirements section above.

Valve operation, maintenance and inspection in addition are governed by

- This section
- Valve manufacturer maintenance instructions
- California Air Resources Approved Monitoring Plan ((CCR 1726.7(f))
  - Natural Gas Underground Storage Facility Monitoring Plan – Facility: McDonald Island (CARB approved plan; consult environmental department for current plan)

  - Natural Gas Underground Storage Facility Monitoring Plan – Facility: Los Medanos (CARB approved plan; consult environmental department for current plan)
  - Natural Gas Underground Storage Facility Monitoring Plan – Facility: Pleasant Creek (CARB approved plan; consult environmental department for current plan)
- Guidance documents and forms listed contained in GSDB

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Section 12 of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Section 12 to this standalone procedure.	Minor language changes were made for clarity. No content changes were made.

Sand Inspection

SUMMARY

Purpose: Provide standards and procedures for sand inspections.

What: Sand inspections are used to monitor wells for the presence of sand and to determine what action is to be taken when sand is found.

Why: When gas wells produce gas at high velocities in the tubing or casing, any sand that is picked up in the flow stream becomes a potentially destructive element. Sand that is blasted against the piping, valves, chokes, or other parts of the system can destroy equipment in a very short time. Further the presence of sand is an indicator of a potential failure of the wells gravel pack and screen liner to prevent sand production.

When: Twice during the winter withdrawal period under a standard clearance: typically, once in January and once in March. Reservoir Engineering has discretion to change frequency based on need to inspect following periods of withdraw outside of the winter withdraw period. Note: If the winter withdrawal period is much shorter than usual, then the sand inspection may only be conducted once during this period. Reservoir Engineering should document reason for single sand inspection on form.

TARGET AUDIENCE

Reservoir Engineering (RE)

Corrosion Department (Corr)

Gas Pipeline Operations and Maintenance (GPOM) - clearances

Sand Inspection

TABLE OF CONTENTS

SUBSECTION TITLE PAGE

STEPS

1. Notify Corrosion Department

Reservoir Engineer (RE): Notify Corr of planned testing schedule as to provide an opportunity to conduct internal visual inspection, solid sampling, or other corrosion testing during the sand inspection.

2. Inspect Sand Residue

RE: Inspect the sand residue, if any, found in the sand traps and record~~s~~ the amount of sand on inspection form based on sand ratings and description shown below in Table 1.

Document any grease or other solids or liquids found during inspection.

3. Review Sand Inspection Ratings

RE: Review sand inspection ratings and provide an electronic copy of the sand inspection results to Corr.

4. **Well Performance Assessment and Response**

RE: Determine whether to downgrade the well's performance utilizing Table H-2 below according to the sand ratings and review results with supervisor. Additionally, consult Figure 1 Sand Inspection Decision Tree for additional mitigation steps to consider, and follow the process as appropriate.

5. **Well Flow Rate Determination**

RE: If the decision process results in changes to the maximum well flow rate, update the maximum well flow rates table and gas storage database.

6. **Notify of Well Performance Implications**

RE: Communicate rate change to GPOM, FIMP (Compression and Processing asset family), and Gas System Planning, and GSAM Engineering.

Table 1. Sand Inspection Rating

Rating	**Sand Description (added to the rating designation)**
0 - No Sand	* - Formation Sand
1 - Slight Trace	** - Gravel Pack Sand
2 - Trace i.e.: Up To ¼ Teaspoon	*** - Both
3 - Measurable Amount i.e.: Up To 1 Tablespoon	Document any grease or other solid or liquids found during inspection
4 - Significant Amount i.e.: Up To 1 Cup	
5 - Critical Amount i.e.: More Than 1 Cup	

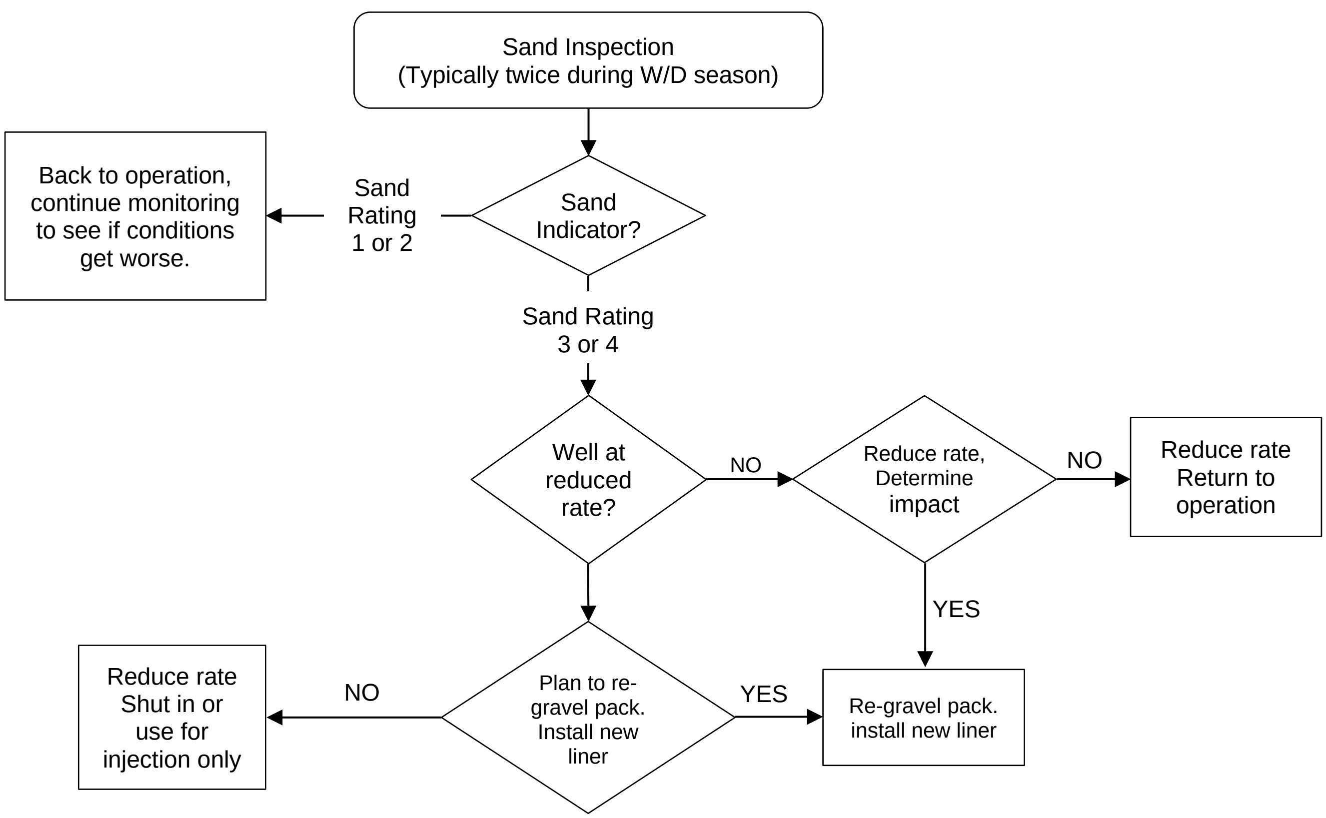
Sand Inspection

Table 2. Sand Inspection Rating and Recommended Action

Rating	Recommended Action *
0 - No Sand	No downgrade
1 - Slight Trace	Monitor
2 - Trace i.e.: Up To ¼ Teaspoon	Monitor
3 - Measurable Amount i.e.: Up To 1 Tablespoon	Downgrade by 25%
4 - Significant Amount i.e.: Up To 1 Cup	Downgrade by 50%
5 - Critical Amount i.e.: More Than 1 Cup	Shut-in, rework or use as injection only.

* If the recommendation is not utilized an explanation should be prepared supporting variance.

Figure 1. Sand Inspection Decision Tree



END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix H4 in Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Sand Inspection

Document Contact

Larry Kennedy, Strategic Planning Chief, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix I5 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Wellhead (Christmas Tree) Pressure Monitoring

UMMARY

PURPOSE

Provide standards and procedures for Wellhead (Christmas tree) pressure monitoring.

WHAT

A wellhead (Christmas tree) is a typical vertical assembly of mechanical elements used in exploration and production of oil and gas as well as in natural gas storage. It is mainly used for fluid control in and out of the well-bore. This test is to monitor Christmas tree pressure on all storage wells to provide wellhead integrity assurance and public and employee safety.

Figure 1. Typical PG&E Christmas Tree.

WHY

This is to evaluate integrity of wellhead seals for maintenance and repair, if necessary, to assure wellhead integrity, and reduce risk of unsafe operation. For surface and subsea Christmas trees, the tree valves are to be tested in the direction of flow.

If a well does not have a positive closed-in pressure, then testing the master valve in the direction of flow may not be practical. In this case, the master valve may be inflow tested.

Wellhead (Christmas Tree) Pressure Monitoring

WHEN

Quarterly.

TARGET AUDIENCE

Reservoir Engineering (RE)

GPOM

Gas System Planning

Corrosion

TABLE OF CONTENTS

SUBSECTION TITLE PAGE

STEPS

1. Testing - Collect Christmas Tree Data

RE:. Collect quarterly Christmas tree pressure data on all storage wells at quarter end using well pressure data forms for storage assets. If any well is not accessible, for reasons such as well is being serviced or not to be operated for safety reasons, RE should document the reason on the well pressure forms.

2. Review Data

RE: Review quarterly Christmas tree pressure data for accuracy.

3. Input Data

RE: Input the quarterly Christmas tree pressure to the GSDB.

4. **Analyze Data**

   RE: Review and analyze the quarterly Christmas tree pressure data comparing to previous quarters to assess wellhead integrity.

5. **Recommend Action**

   RE: Recommend action plans for wellhead maintenance activities.

6. **Publish Results**

   RE: Communicate results to GPOM, Planning, and Corrosion.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

Procedure 14c, - Well Risk Ranking (monitoring and inspection condition factor)

Wellhead (Christmas Tree) Pressure Monitoring

Well pressure data forms for Los Medanos, McDonald Island, and Pleasant Creek found in the Gas Storage database.

1. Los Medanos well pressure data form.
2. McDonald Island well pressure data form.
3. Pleasant Creek well pressure data form.

APPENDICES

N/A

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix J6 in Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Larry Kennedy, Strategic Planning Chief, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix J6 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Annular Pressure and Gas Sampling Monitoring

SUMMARY

Purpose: This procedure provides guidance for creating annular pressure and gas sampling monitoring and action plans (CCR 1726.7(a)).

What: This is to establish action plans for monitoring the annular pressures

Why: Monitoring is performed of the annular space pressure to indicate potential well integrity issues, identify gas migration issues, and utilize the sampling data for the future usage for well casing integrity and employee and public safety.

When: Pressure collection is completed in accordance with Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring.

TARGET AUDIENCE

Reservoir Engineering (RE)

GPOM

TABLE OF CONTENTS

Annular Pressure and Gas Sampling Monitoring

REQUIREMENTS

1 Definitions – See Standard 10 Definitions

1.1 Observed sustained surface pressure (OSSP) – any validated pressure reading recorded used in monitoring.

1.2 Anticipated surface pressure (ASP) – pressure determined based on historical data and trending to utilize for responding to potential gas migration

2 Collect Pressure Data

GPOM and Reservoir Engineering: Collect pressure data following Procedure N10, Wellhead Annuli Pressure Collection, Pressure recording gauges and SCADA may be used.

3 Review received pressure data and determine ASP and MASCP

Reservoir Engineer: Review and assess the data for the following:

3.1 determine an anticipated surface pressure (ASP) for each well's annulus based on a wells historical data and review annually but not exceed 15 months

3.2 determine the wells Maximum Allowable Surface Casing Pressure (MASCP)

- MASCP is equal to the surface casing depth (feet) x 0.25 psi

3.3 determine if a well's surface casing annulus anticipated surface pressure is equal to or greater than 100 psig, the following shall at a minimum be completed

- Review and assess the relationship to Maximum Allowable Surface Casing Pressure (MASCP).
- Collect gas sample(s) (Section 4)
- Document if unable to collect gas sample
- Conduct a surface casing blow down and build up test (Table 1 – Standard Annular Test)
- Evaluate and document results and action plan as necessary for the well (Section 6)

Note: Any wells identified under items 3.3 shall be documented and reported to the GSAM director, manager, supervisor and engineer. A written plan of action should be developed to assess the anomalous pressure and could include shutting in the well immediately, conducting injection or withdraw testing, and collecting additional pressure data. For anomalous events, if the deviation from the trend seems unusually large or if any of the survey data looks odd enough to require confirmation, request a re-test of the annular survey.

Annular Pressure and Gas Sampling Monitoring

4 Assess existing monitoring and action plans

RE: Review existing monitoring and action plans and where needed direct whether to sample and/or conduct blow down/build-up test. Collected samples should occur at a minimum annually or described in the wells with action plan. A standard test shall be conducted in accordance with Table 1 unless otherwise directed by RE.

Table 1

Standard Annular Test
Collect gas sample(s) and document if unable to collect gas sample.
Conduct a surface casing blow down and build up test.
Manual record blowdown pressures at 1, 2, 3, 4, 5, 10, 15, 20, 25, and 30 minutes or use SCADA reading may substitute.
Record or use SCADA reading for buildup pressures at intervals specified by engineer.

NOTE: Blowdown pressure recording frequency may be changed by the engineer based on performance data and may include use of digital recording devices or SCADA readings.

5 Deliver the annular gas samples

RE Specialist: Deliver the annular gas samples to PG&E load center for analysis or other sites as directed by engineers.

6 Input data and publish

RE Specialist: Input the pressure, venting rate, and/or gas sample results in the GSDB and distribute results to the GSAM engineering team.

7 Analyze data

Reservoir Engineer - Trend pressure, venting rate, calculate emissions volume, and gas sampling data and perform field and well integrity evaluation consulting the well files for any historical data points and in review of possible causes and remediation in Table 2. The following steps shall be completed to determine if the observed sustained surface pressure (OSSP) is migrated storage gas:

Annular Pressure and Gas Sampling Monitoring

7.1 Determine if a well's observed sustained surface pressure (OSSP) exceeds its anticipated surface pressure (ASP) by 100 psi (CCR 1726.7 (d)(2) and (3)), then following shall at a minimum be completed:

- o Bleed off annular pressure and track pressure and time for the well to build up pressure back to the observed sustained surface pressure (CCR 1726.7(d)(3)(A)). (see Table 1)
- o Sample the fluids building up in the annulus (CCR 1726.7(d)(3)(B)). (see Table 1)
    - o Perform a chemical fingerprinting of the sample(s) or other diagnostic tests as determined necessary.
    - o Evaluate the samples for migration of storage gas
    - o Document if unable to collect gas sample
    - o Determine if the buildup is due to migration of storage gas (Table 2 – Potential Causes)
    - o Document assessment and review in wells action plan (see 6.2 and 7)
- o If not due to storage gas migration (CCR 1726.7(d)(3)(C):
    - o Determine new alarm set point that shall not exceed 100 psi plus the observed sustained surface pressure (OSSP)
    - o Determine if the new alarm set point pressure that would pose a risk to casing integrity (CCR 1726.7(d)(3)(C)
    - o Submit new alarm set point pressure in an update to the Well Annular Monitoring System and Response Plan containing the set points for all wells to CalGEM for approval.
    - o Notify GPOM of alarm set point change and update Well Annular Monitoring System and Response Plan using Management of Change
    - o If the new alarm set point pressure poses a risk to the well integrity, then develop action plan to address the risk and submit to CalGEM for approval. (see 6.2)
    - o Develop and document action plan and long-term monitoring actions. (see 6.2 and 7)
- o If due to storage gas migration (CCR 1726.7(d)(3)(E):
    - o Develop plan to conduct further testing to determine the pathway of migration and take remedial action as defined in action plan (see 6.2 and 7)
    - o Submit plan to CalGEM for approval.

Annular Pressure and Gas Sampling Monitoring

Table 2 – Potential Causes

Potential Cause of Annular Pressure		**Analysis Results or Symptom**	**Potential Remedial Solutions**
1	Loss of integrity in wellhead seals	Pressure is variable but often could be high pressure but quick blow down due to small volume since a very limited space can be filled and could also see spikes with temperature impact.	Inject packing at wellhead seals
2	Gas migration behind pipe through cement sheath of low integrity	Pressure may appear highly variable and gas may accumulate considerable volume over time. This is dependent on the transmissibility of the leak path and may depend on the ability of reservoir pressure to overcome the hydrostatic head of liquid in the annulus. It may also depend on whether shallow permeable zone has been charged by gas moving in the annulus over time. Good application for log investigations – cement bond, noise, temperature, neutron, etc.	Remediation may include squeezing the leak path itself, block squeezing or squeeze cementing above the current top of cement (assuming there is no formation below that point that can be charged up as a leak collection pool for the gas). Seal-tite (and perhaps others) also claims to have a chemical solution, injecting a polymer down the annulus that gels at a pressure differential (this can be fairly expensive). Plugging the downhole formation and sealing it off from the annulus is an option if the well has little or no value in operations. Milling a window and squeeze cementing, along with running and cementing a full liner, also has been successful at shutting off these sorts of leaks
3	Casing collar leaks	**Type 1)** Pressure build may come and go and manifest irregularly if hydrates can form to seal off small leaks. **Type 2)** Substantial leaks will likely always show up suddenly. Noise, temperature, and neutron logs can be effective at defining the leak point(s).	Remedial solutions include liners (cemented or on packers), internal casing patches, chemical seals (Seal-tite, see above in #2), or squeeze cementing. If close to the surface, sometimes the joints can be backed off and replaced.

Annular Pressure and Gas Sampling Monitoring

Potential Cause of Annular Pressure		Analysis Results or Symptom	Potential Remedial Solutions
4	Leak due to corrosion hole	This type of leak will suddenly manifest itself and can be variable in its pressure and rate depending on the size and depth of the hole and the annulus medium through which the gas must travel.	Remedial options include installation of liners, patches, back off casing and replace (if near the surface and un-cemented), etc. The probable presence of a pit or of pre-existing conditions leading to progressive corrosion pit growth should show up on an MFL, ultrasonic log or other similar casing inspection survey. Casing should be recovered where possible for pit geometry and depth characterization; a casing inspection log (e.g. MFL or ultrasonic) should be run prior to the casing recovery.
5	Leak due to gas emanating from a natural gas-bearing zone which is not isolated from the annulus	The presence of naturally occurring gas should be verified via well history and local information. Gas sampling to determine any differences between storage gas and native gas from another zone is important. It may be that gas in the annulus is a combination of native gas from another zone and gas leaking to or through the annulus from storage for whatever reason.	Isolation efforts as described in (4) above are the best way to treat this problem if the amount of gas creates safety or environmental problems, or if native gas leaks may be combined with storage gas leaks. Log investigations can clarify issues related to potential dual source problems

7.2 Data storage

Data from the test and sampling shall be stored in the well's monitoring and action plan for trending analysis that includes pressure versus time and historical sampling comparisons.

> *Note: The monitoring and action plan shall include: first time event; historical pattern of the annular pressure in about this range of volume; historical pattern of annular pressure but present survey finds more volume than usual; or other appropriate comment based on the history. Commentary may also summarize information: well completion and rework history, history of annulus pressure and any prior attempts to define sources of pressure or remedial/repair attempts, log review data (gamma ray*-neutron *(CCR 1726.7(b)(2)(D)*, *cement bond, and casing inspection log (e.g. MFL or Ultrasonic)).*

7.3 Remedial actions

Remedial actions may be determined. The well will remain out of service until repairs are completed or the well will be placed back in service.

8 Recommendation for Action

RE - document recommendation for action. This recommendation may include: continue to monitor; run log investigations or other physical tests; gas sampling; wellhead packing; or other remedial action. The action should be related to the amount of the gas loss, safety and environmental concerns.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

GSAM Standard 10, Casing Pressure Tests and Annulus Monitoring Standard

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

Pressure collection is completed in accordance with Procedure N10, Wellhead Annuli Pressure Monitoring

Annular Pressure and Gas Sampling Monitoring

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix L8 in Underground Storage Risk and Integrity Management Plan,

Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Larry Kennedy, Strategic Planning Chief, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix L8 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Individual Well Pressure and Performance Monitoring

SUMMARY

PURPOSE

Monitor individual well performance.

WHAT

This procedure addresses individual well injection and withdrawal performance monitoring. This monitoring is the real-time surveillance solution that combines well data analysis with operator and engineer's expertise thereby allowing engineers to make decisions regarding asset integrity, risks and corrective or preventative actions based on facts and data.

Monitoring of individual well performance is performed to develop and optimize individual injection plans, withdrawal flow rates, and to identify, assess and resolve well performance issues such as:

- inadequate deliverability
- low well flow performance relative to potential
- higher well asset maintenance costs
- low field efficiency

This supports the responsibility of GSAM to provide storage asset capacity as required by system operations, marketing, and operations and maintenance organizations to meet the needs of PG&E storage customers throughout the year.

WHEN

On-going.

SAFETY

n/a

TARGET AUDIENCE

Reservoir Engineering (RE), Gas Storage Asset Management Department (GSAM)

Gas Pipeline Operation and Maintenance (GPOM)

Gas System Planning

Individual Well Pressure and Performance Monitoring

TABLE OF CONTENTS

SUBSECTION TITLE PAGE

STEPS

1. GPOM Personnel Steps

Informs RE of any well performance issues, such as hydrate formation, well production problems, well overflow.

2. Reservoir Engineering Steps

RE Specialists should inform RE engineers of any well performance issues noted when performing wellhead and annular pressure monitoring.

RE personnel evaluate individual well performance; and any well performance issues, such as hydrate formation, well production problems, well overflow.

RE personnel consider the previous individual flow test results, interference, and past performance issues.

2.1. Log into the Cimplicity control system to review well flow rates relative to established well performance or flow rates recorded during special testing (i.e., flow rates recorded on forms during maximum flow tests or individual testing).

2.2. Investigate any system reporting issues in Cimplicity if necessary and report to Operations and RE.

2.3. Report the results of well flow rate performance investigation within RE.

2.4. Input data and results to the Gas Storage database and update max flow rate tables to keep track of well performance and manage remediation prioritization.

Individual Well Pressure and Performance Monitoring

2.5. Initiate the Management of Change (TD-4014P-03) process to revise the max flow rate tables by completing forms, and initiating and obtaining approval. Maintain MOC communication, forms, and approvals on Gas Storage database.

2.6. Communicate the well performance results created in accordance with TD-4437P and the implications on the total field performance to Gas System Operations, Wholesale Marketing & Business Development, Station Services, Operations & Maintenance, and Gas System Planning. Provide well performance updates in a timely manner.

END of Procedure

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Reservoir Engineering, GSAM

GPOM

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

GSAM Standard 14A, Evaluation of Wells and Attendant Production Facilities

GSAM Procedure N10, Wellhead Annuli Pressure Monitoring

TD-4014P-03, Station Management of Change

Individual Well Pressure and Performance Monitoring

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces RIMP Appendix M9 in Underground Storage Risk and Integrity Management Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix M9 to this standalone procedure format	Minor language changes were made for clarity. No substantial content changes were made

Wellhead Annuli Pressure Collection

SUMMARY

This procedure addresses wellbore annuli pressure collection.

The accurate collection of pressure data allows for field and well integrity evaluation to ensure safety, assurance of no gas loss for inventory verification, and utilization for gas reservoir engineering analysis. Surface wellheads are used to support casing & tubing strings, isolate/and control pressure during the drilling operation and monitor annulus casing during production.

Purpose: PG&E’s current well construction can include up to four separate annuli requiring monitoring based on well configuration: 1-surface casing, 2-production casing, 3- tubing, and 4- cemented inner string where installed.

What: Wells that have a cemented inner casing string installed and requires a fourth point of monitoring. See Figures N-1 and N-2 below, for typical wellhead configuration with 3 monitoring and 4 monitoring points, respectively. Figure N-3 provides additional clarity on downhole construction of concentric casing strings. Note: the current list of wells with inner strings is maintained on Reservoir Engineering Sharepoint and updated at the conclusion of rework season for any wells configured with an inner string.

When: This procedure is performed daily (GPOM) & weekly (Reservoir Engineering Specialist or engineer).

TARGET AUDIENCE

GSAM

GPOM

Wellhead Annuli Pressure Collection

TABLE OF CONTENTS

REQUIREMENTS

1 Collect Pressure Data

GPOM/RE Specialist - Use calibrated portable gauges to collect daily pressure reads at each well, including injection/withdrawal wells and observation wells, in three PG&E owned gas storage fields. Collect daily pressures from tubing, casing, surface casing, and inner casing string where installed.

Pressure readings may be collected with the use of digital recording gauges or a SCADA operating system in leu of portable gauges.

2 Record and Publish Pressure Data

GPOM: If GPOM gathers pressures, record pressures and remarks using mobile device (i.e. PRONTO forms) and submit via mobile application to RE.

RE Specialist (RES): If RES gathers pressures, record pressures and remarks using mobile device (i. e. PRONTO forms) and submit via mobile application to RE record pressures. Alternatively, record remarks and spot flow rates in Excel spreadsheet format and submit to RE.

Pressure readings may be collected with the use of digital recording gauges or a SCADA operating system in leu of portable gauges. The SCADA operating system recordings are guided by the Well Annular Monitoring and Response Plan to achieve real time monitoring capabilities and treatment of data collection, monitoring, archival, reporting and response to data issues.

3 Input Data to the GSDB

Reservoir Engineer: Input the received pressure data to the GSDB

4 Perform Data Review

Reservoir Engineer: Review received pressure data for completeness and accuracy, no less often than on a weekly basis.

Reservoir Engineer: trend

5 Trend data and Data Validation

Reservoir Engineer. Trend annular system data to validate data consistency against manually recorded pressures and review for anomalies in the data (Well Annular Monitoring and Response Plan Section 4 – Data Validation).

6 Communicate data

Reservoir Engineer: Communicate data validation issues or data anomalies, to RE and GPOM.

END of Requirements

DEFINITIONS

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, Gas Storage Asset Management Department

Wellhead Annuli Pressure Collection

GOVERNING DOCUMENT

GSAM Standard 1

GSAM Standard 10, Casing Pressure Tests and Annulus Monitoring Standard

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

…..

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

Pressure collection is completed in accordance with Standard 10, Wellhead Annuli Pressure Monitoring

Procedure L8, - Annular Pressure and Gas Sampling Monitoring

APPENDICES

Appendix 1 - Diagram of wellhead with three monitoring points

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix N10 in Underground Storage Risk and Integrity Management Plan,

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

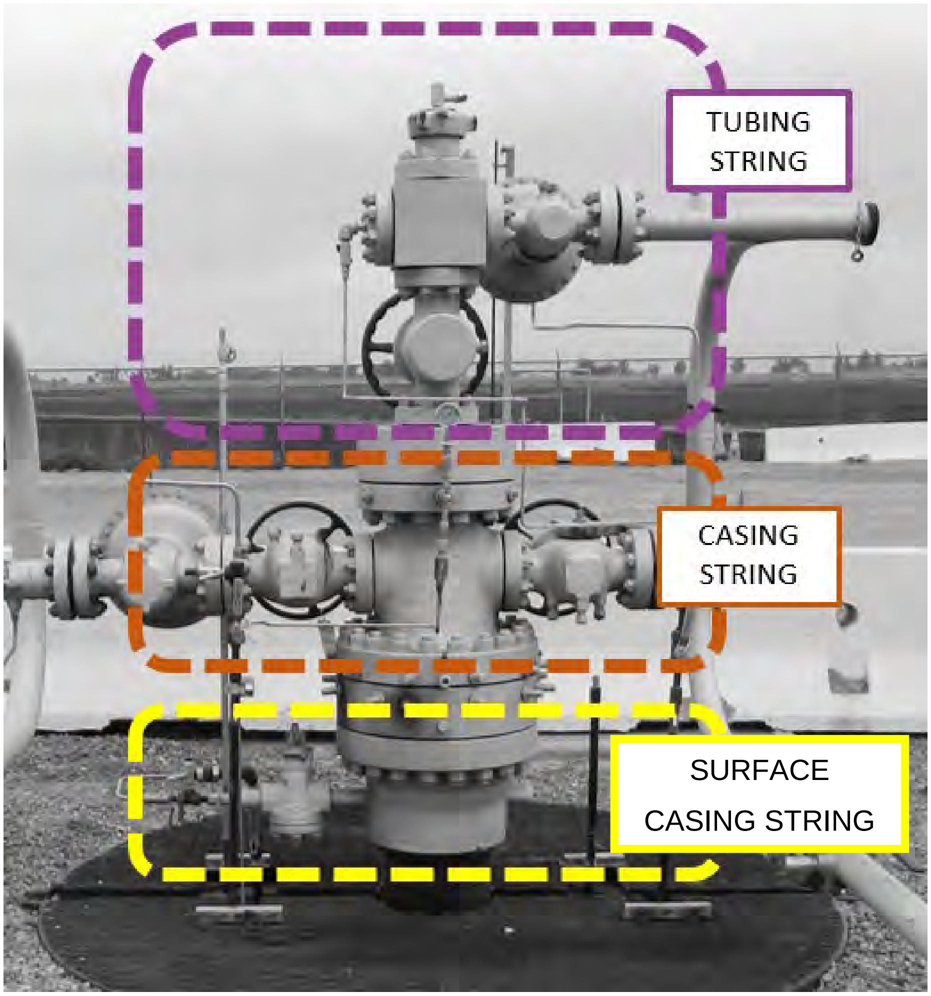
Wellhead Annuli Pressure Collection

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix N10 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

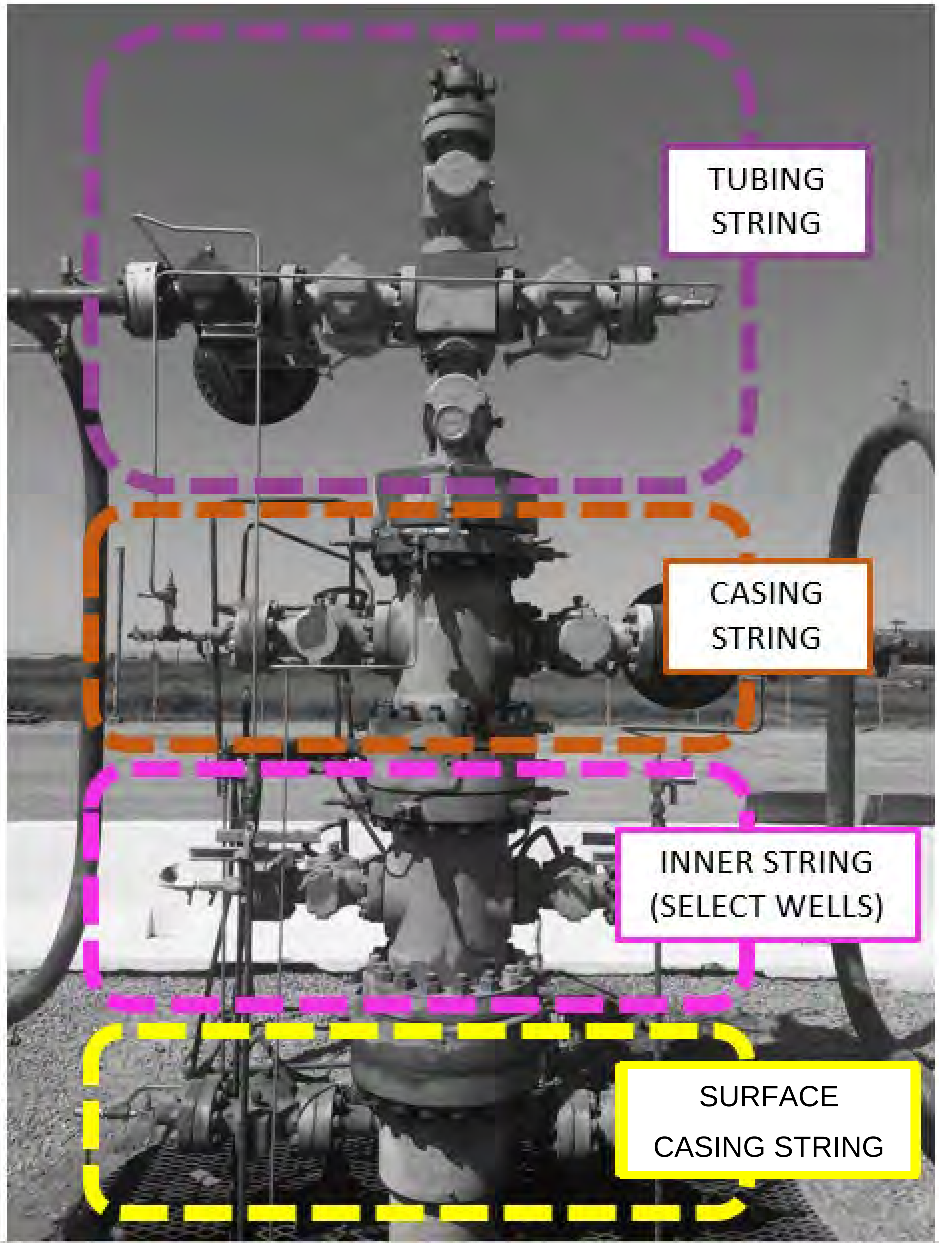
Wellhead Annuli Pressure Collection

APPENDIX 1 – Diagram of wellhead with three monitoring points



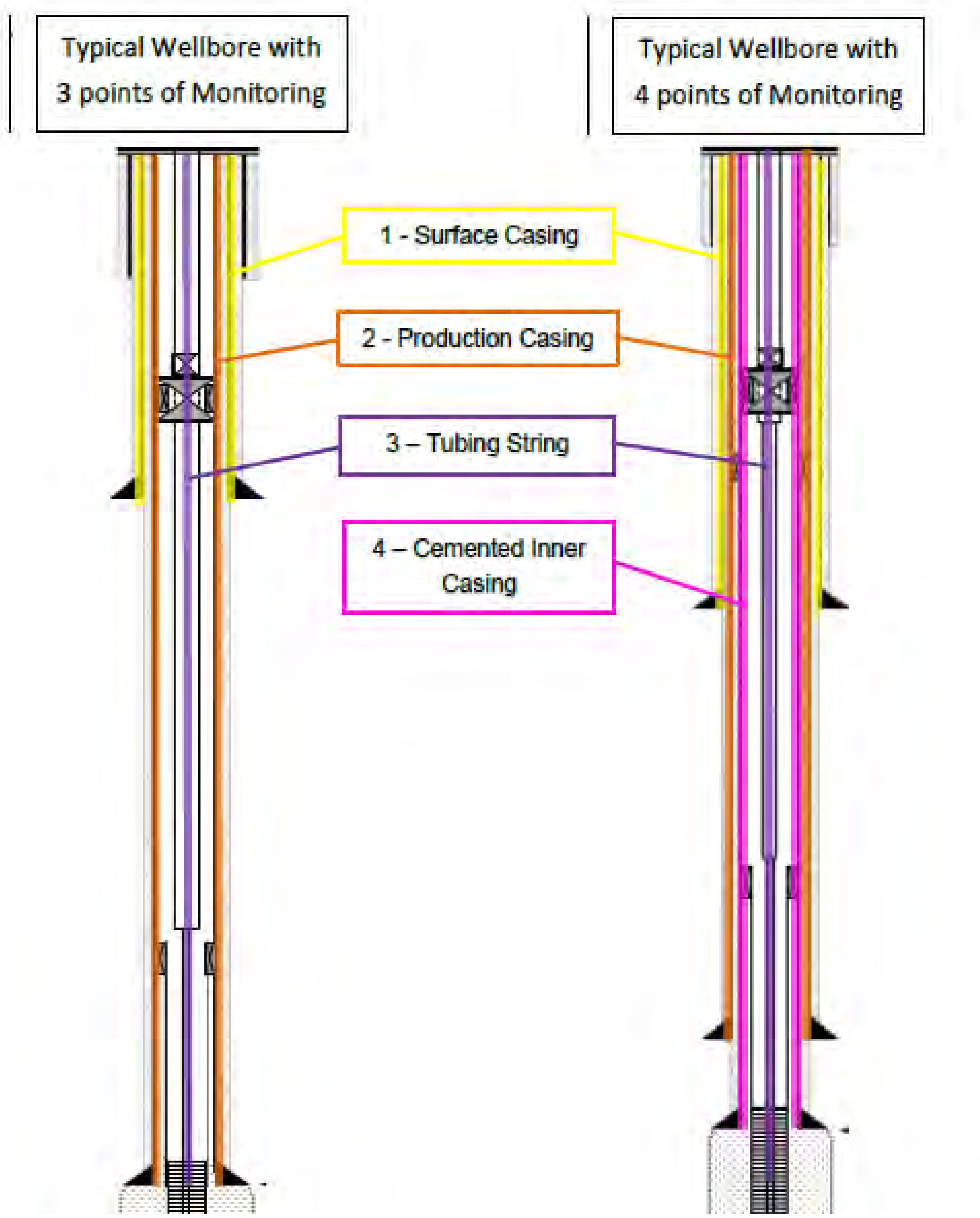
Wellhead Annuli Pressure Collection

APPENDIX 2 – Diagram of Wellhead with four monitoring points



Wellhead Annuli Pressure Collection

APPENDIX 3 – Typical wellbore diagrams for wells with 3 (left) and 4 (right) points of pressure monitoring



Gas Sampling Observation and Storage Wells

SUMMARY

Purpose: This procedure provides standards and procedures for gas sampling of observation and storage wells.

What: This is the process for taking observation and storage-well gas samples to provide an understanding of the storage gas quality, monitor gas movement within a storage zone and to monitor the potential for gas migration away from the storage zone or movement to other porous zones above or below the storage zone.

An observation well (OBS) also called a key indicator well is used to monitor the operational integrity and conditions in a gas reservoir, the reservoir protective area or the strata above or below the gas storage horizon. Natural gas is injected into the formation, building up pressure as more natural gas is added.

Why: This is to monitor the well gas samples to improve well integrity monitoring of corrosion potentials due to gas composition, identify potential storage gas movement / migration issues, differentiate between storage gas and other gases and utilize the sampling data for reservoir engineering analysis. Gas samples are obtained and analyzed to determine if changes in gas composition occur over time. The samples may be taken from OBS wells completed in the storage zone and/or OBS wells completed in porous zones above or below the storage zone. Changes in gas composition may indicate movement of storage gas toward storage boundaries. This information is valuable for identification of potential storage gas migration.

Two of the most important characteristics of an underground storage reservoir are its capacity to hold natural gas for use rate and the rate at which gas inventory can be withdrawn its deliverability rate. Through an observation and storage well gas sampling program an operator can monitor for gas movement in the reservoir that maybe indications of gas movement or migration.

When: As defined in Sampling Plan

TARGET AUDIENCE

GSAM Reservoir Engineering (RE)

PG&E Load Centers

Gas Pipeline Operations and Maintenance (GPOM)

Gas Sampling Observation and Storage Wells

TABLE OF CONTENTS

SUBSECTION TITLE PAGE

STEPS

1. Sampling plan ~~Monthly observation and gas samples~~

Reservoir engineering team will provide the list of wells to be sampled and specify the frequency of sampling for the specific well. Sampling for reservoir integrity verification should be completed on at least a monthly basis and sampling for other investigations should be specified by the RE engineering.

2. Observation and gas samples

RE collects observation and selected storage well gas samples

3. Sample Delivery

RE delivers the observation and selected storage well gas samples to PG&E load center for analysis.

4. Data Entry

RE inputs the observation and selected storage well gas sample results in the gas storage database

5. Review and Analysis

RE reviews and analyzes the observation and selected storage well gas sample results comparing to the previous storage gas sample results.

5.1. The following is a summary of questions the reservoir engineer attempts to answer in the evaluation of the pressure responses and gas sample data from an OBS well or a storage well.

5.1.1. What is the fluid observed in the well – oil, gas, brine, etc.? If gas, does the gas sample reflect native or storage gas?

5.1.2. Which formation is the well monitoring – the storage zone, fringe area of the storage zone or potential porous zones above or below the storage zone into which gas could migrate?

5.1.3. Are pressure changes observed at the surface or bottom hole?

5.1.4. Status of nearby wells – what does the data from offsetting wells provide?

5.1.5. Well integrity history

5.1.5.1. Does annular pressure monitoring data indicate the integrity of tubing or casing?

5.1.5.2. Are apparent defects present on casing inspection logs? If so, what is the rate of change of apparent defects?

5.1.6. Well location – is the well near houses, buildings, roads or waterways?

5.1.7. Does the pressure of this well track closely with the reservoir pressure?

5.1.8. Is this well being used for gas injection and/or gas withdrawal?

5.1.9. Is the drainage area from this well a low percentage?

5.1.10. Is the gas analysis from this well similar to the gas analysis from the remainder of the reservoir?

6. Anomalies and Actions

RE determines if any anomalies exist in the data and recommends actions

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

Gas Sampling Observation and Storage Wells

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix O11 in Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix O11 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Third Party Activities

SUMMARY

Purpose: Provide standards and procedures for monitoring third party activities inside and outside of gas storage properties.

What: This is to monitor third party activities inside and outside of gas storage asset properties including drilling and production for potential extraction of storage gas.

Why: This is to protect gas storage reservoir integrity and protect against loss of storage gas from potential extraction of storage gas by third parties.

When: Perform surveillance whenever working in gas storage facilities.

TARGET AUDIENCE

Reservoir Engineering (RE)

GPOM

TABLE OF CONTENTS

1. Reservoir Engineering Steps

1.1. Survey and monitor third party drilling activities inside and outside of gas storage asset properties on a quarterly basis. If an increase in drilling or remediation activity or change in production from existing third-party wells is observed, increase the monitoring frequency.

1.2. Open CalGEM GIS (Well Finder).

1.3. Review PG&E and third party permits as well as third party active and idle wells

1.4. Obtain well logs from the CalGEM to determine zones of production from third party Permit activities, if available.

1.5. Obtain periodic wellhead pressures and gas samples from third party wells, if available.

1.6. Compare storage pressure and storage gas samples with the production wells.

1.7. Enforce no-drill through rights inside gas storage asset properties if agreements exist or regulations are applicable.

1.8. If well is drilled within 75’ from the gas storage asset property line, inform director and CalGEM.

1.9. Plot well drilling and production activities on reservoir maps.

1.10. Update and plot activities on reservoir maps as new activities are obtained.

1.11. Communicate results to the Land, Operations & Maintenance, and Reservoir Engineering departments.

1.12. If third party drilling activities exhibits potential extraction of storage gas, elevate to higher level management for mitigation decision.

1.13. Specific Steps for Existing Wells

- Thoroughly review the state regulations for third-party wells penetrating PG&E’s gas storage reservoirs and specific state regulations pertaining to individual reservoirs and verify that these rules are strictly followed.
- Identify well location, serial, and state permit or API number, production interval, total depth, and operator for all wells within PG&E storage field boundaries.
- Obtain available well data, maintain schematics, and logs, and conduct a thorough review of state files.
- Obtain gas, oil, and water production data from the state and/or well data from service companies.
- Monitor production data annually and look for anomalies.
- Sample the storage reservoir gas and, if necessary, obtain a gas analysis from the nearest existing storage well(s) to be used for comparison purposes.
- Open dialogue with outside operator and obtain written permission to perform the following, if practicable:
    - Routinely monitor all annular and tubing pressures.
    - Sample the gas streams including the tubing and the tubing-casing annuli (TCA) and perform a gas analysis at least once but more often if anomalies are identified. Resample if the producing horizon changes.
    - Seek information on plugged and abandoned wells within the protection acreage.
    - For wells located within the lateral and vertical buffer zone being plugged and abandoned by a third party, confirm that the storage reservoir will remain isolated to protect its integrity.

- Conduct an initial review of plugging records, and again only for cause, such as changes in condition found by leak survey or other observations.
- Thoroughly document all considerations and actions above.

1.14. Specific Steps for New Wells

- Review the design and completion of the well. Verify that the storage zone will be properly isolated by cement and that the casing design is adequate for storage field pressures.
- To the extent practicable, monitor the drilling, cementing, logging, and perforating operations of third-party wells.
- Review all available logs and identify any anomalies.
- If PG&E suspects that the integrity of its storage reservoir has been breached by a new well, PG&E will contact the operator and attempt to negotiate a plan for remedial action.
- Thoroughly document all considerations and actions above.

2. Documentation Steps

2.1. Complete review in form “Third Party Monitoring Activities Form.xlsx” located in the GSAM G-Drive under folder “Third Party Monitoring.”

2.2. Save completed form with date of review with extension of XXXX_XX_XX (Year-Month-Day)

END of Requirements

DEFINITIONS

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Reservoir Engineering, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

Standard 8, Reservoir Integrity Management, Section 5 Monitor Third-Party Existing and New Wells

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in standard 1, Section 3

Third Party Activities

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix Q13 in the Underground Storage Risk and Integrity Management Plan, Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix Q13 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Downhole Safety Valve (DHSV) Leak-by Testing

SUMMARY

Purpose: Provide standards and procedures for the testing of safety valves.

What: Wells equipped with “uphole” safety valve (UHSV) installed on the pipeline near the wellhead or a “downhole” safety valve (DHSV) or surface controlled subsurface safety valves (SCSSV) typically have valves installed 250 feet below ground level to provide emergency shutdown in the event the storage well cannot be isolated by the wellhead master valve. UHSV and DHSV valves are surface controlled, hydraulically operated and are “fail safe” type valves (hydraulic control system pressure keeps the valves open, and the valves close on loss of hydraulic control system pressure). This procedure uses API Recommended Practice 14B Sixth Edition, September 2015 as guidance in developing the test procedures.

Procedure: The Reference Document section at the end of this procedure lists these documents for reference. The most current editions must be obtained from GSAM Reservoir Engineering.

Frequency: See TD-4521S, Gas Valve Maintenance Standard.

Why: The testing is to ensure that the Safety values are meeting the CalGEM regulation requirements and reliable operations to meet gas system and customer demands. The UHSV and DHSV is a major preventive measure installed to prevent an uncontrolled release of the reservoir fluid is an emergency scenario such as an explosion or in situation where the wellhead integrity is lost. It is designed in such a way that the well flow performance causes it to close while the hydraulic control forces it open. The hydraulic control is usually operated from the surface as indicated earlier.

When: Test under a standard clearance and scheduled to meet frequency of once every 6 months (CCR126.8(a))..

TARGET AUDIENCES

Gas Pipeline Operations and Maintenance performs testing. Refer to Station Operating Procedures for Los Medanos, McDonald Island, and Pleasant Creek in the GPOM library, and the procedures in this document.

Reservoir Engineering

- reviews test data for reasonableness and completeness.
- evaluates test data and assigns ratings to prioritize the malfunctioning UHSV and DHSVs for replacements.

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Downhole Safety Valve (DHSV) Leak-by Testing

1. Reservoir Engineering Steps

1.1. DHSV and Control Line Evaluation:

1. Enter the results of the evaluations and the ratings into gas storage database. Base the ratings on Tables 1, 2, and 3 below. Table 1 thru 3 are provided for the engineer to rate the control lines functional integrity and compare performance from inspection to inspection

2. Prioritize the DHSV replacements and inputs in the GSDB and investment planning processes.

> **NOTE: Within 90 days of finding that a safety valve is inoperable, the PG&E shall repair the valve or temporarily plug the well (CCR 1726.8(a))**

Table 1. RC DHSV, RC-2 DHSV Control Line Ratings

RATING	DHSV/ Control Line Ratings (Pressure Build-up/ 45 mins)
0	No leakage
1	1 to 100 psig
2	101 to 200 psig
3	201 to 300 psig
4	301 or higher
5	Well does not blow down

1.2. Historical Evaluation of DHSV and Control Lines Prior to 2014:

Prior to 2014 PG&E utilized the following tables for the different DHSV utilized and revised valves rating to be based on pressure due to inability to utilize the volume measurement devices. Historical data still reflects the former rating system (valves types have been standardized beginning with the equipping of wells in 2018 with tubing and packer, thus historical information is not as relevant).

1. to Enter the results of the evaluations and the ratings into gas storage database. Base the ratings on the DHSV ratings below in Tables 2 and 3.

2. Prioritize the DHSVs replacements and inputs in the GSDB and investment planning processes.

Table 2. RC DHSV Ratings

RATING	RC DHSV/ Control Line Rating (Pressure Build-up/ 45 mins)
0	No leakage
1	1 to 100 psig
2	101 to 200 psig
3	201 to 300 psig
4	301 or higher

Table 3. RC-2 DHSV Ratings

RATING	RC-2 DHSV Rating (Flow test / 10 mins)
1	≤ 50.0 cu/ft
4	> 50.0 cu/ft

END of Requirements

Downhole Safety Valve (DHSV) Leak-by Testing

DEFINITIONS

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Reservoir Engineering, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in standard 1, Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

Table 4, Down Hole Safety Valve Guidance Documents

Guidance Doc	Title / Notes	Form
Section 2 McDonald Island Downhole Safety Valve (DHSV) Leak-by Test	Procedure for leak-by testing McDonald Island Station Downhole Safety Valves (DHSV) in fully pressurized well	MI DHSV LEAK TEST FORM.xlsx
Section 3 McDonald Island Downhole Safety Valve (DHSV) Leak-by Test – Well out of Service	Procedure for testing DHSV during station outage at McDonald Island	MI DHSV LEAK TEST FORM.xlsx
Section 4 Downhole Safety Valve (DHSV) Leak-by Testing: Los Medanos	Los Medanos Station Operating Procedures Downhole Safety Valve (DHSV) Test	LM DHSV LEAK TEST FORM _REV1.xlsx

n/a

Downhole Safety Valve (DHSV) Leak-by Testing

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix R14 in the Underground Storage Risk and Integrity Management Plan, March 29, 2019 Revision 5.

Rev 5

Document Approver

Larry Kennedy, Strategic Planning Chief, Director, GSAM

Document Owner

Lucy Redmond, Director, GSAM

Document Contact

Allan Lee, Manager, RE Integrity Management, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix R14 to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Management of Change for Well Rework

SUMMARY

Purpose: This procedure describes the requirements and steps for management of change to be applied for well engineering and design associated with rework and drilling operations.

SAFETY

n/a

TARGET AUDIENCE

This standard applies to all engineering and technical personnel engaged in rework and drilling operations, primarily:

- Gas Storage Asset Management (GSAM)
- Gas Pipeline Operations and Maintenance (GPOM)
- Contractors and services providers

TABLE OF CONTENTS

Management of Change for Well Rework

Background

Well engineering, design and rework shall include and follow the MOC process as described below in one of the following categories. Examples of the qualifying events are listed below each category for ease of reference. The following pages include the specific instruction for each category.

Not all MOC changes will require a change to the permit requirements issued by state, federal, or local agencies, but any Category 1 or Category 2 MOC changes not within permit requirements shall follow Category 3 MOC instructions.

Closeout and Documentation

On call engineer or designee is responsible for the documentation, approval, and close out of the MOC.

Management of Change for Well Rework

Quick Reference for MOC Categories

- **Category 1 MOC** –
  - **Documentation Requirement** – Daily field report
  - Approval Requirement: inform and communicate

Category 1 MOC Example Activities	1) Increase or decrease mud weight 2) Increase or decrease mud viscosity 3) Change of logging sequencing for efficiency 4) Change of retrievable BP setting depths 5) Change of chemical or mechanical cut depths

- **Category 2 MOC** –
  - **Documentation Requirement**: Daily field report, MOC Form and MOC Log
  - Approval Requirements: Communication and on-call engineer or manager approval

Category 2 MOC Example Activities	1) Change of logging depths 2) Change of under-reaming depths 3) Change of open hole sizes 4) Change of pipe recovery operation

- **Category 3 MOC** –
  - **Documentation Requirement**: Daily field report, MOC Form and MOC Log
  - Approval Requirements: Principal engineer or manager, and director of GSAM.

Category 3 MOC Example Activities	1) Changes that impact permits 2) Change of production casing setting depths during cementing 3) Change of production liner packer setting depths 4) Sidetrack 5) Abandon 6) Unplanned plug-back 7) Pipe or wireline stuck in the hole that requires backing or shooting off tools

Management of Change for Well Rework

STEPS

1. Category 1 MOC – Approval Requirement: Inform and Communicate

Apply the category 1 MOC process to certain events and/or step changes such as those listed below. This process is employed to inform and communicate only during well rework and drilling operations.

1) Increase or decrease mud weight
2) Increase or decrease mud viscosity
3) Change of logging sequencing for efficiency
4) Change of retrievable BP setting depths
5) Change of chemical or mechanical cut depths
6) Changes by IM team scope (i.e. downhole run, additional logging)

Note: Category 1 MOC changes must be within permit requirements.

These changes will follow the Category 1 MoC process structure with the following steps:

A. **Cat 1 - Initiation by the Well Site Manager (WSM) or On-Call Engineer**

a. Gather and document information about event that triggered the change.

b. Review and discuss with On-Call Engineer to determine if additional support is necessary for risk assessment.

B. **Cat 1 - Approval**

a. Communicate the change and what triggered the change by sending an email to all stakeholders and contractors.

b. Record the change in the daily report and program revision number should be documented on Rework Daily Report Workbook. .

c. Proceed with change.

d. On-call engineer: Review the change within 24 hours and promptly raise issues or concerns if any arise.

C. **Cat 1 - Communication**

a. Make change in the well rework program if necessary and highlight the change.

b. Send revised well rework program to all stakeholders including contractors denoting revision number of the revised program.

Management of Change for Well Rework

c. Lead engineer or designee: Review the revised program with on-site WSM, document MOC level in Program, and update MOC log with change.

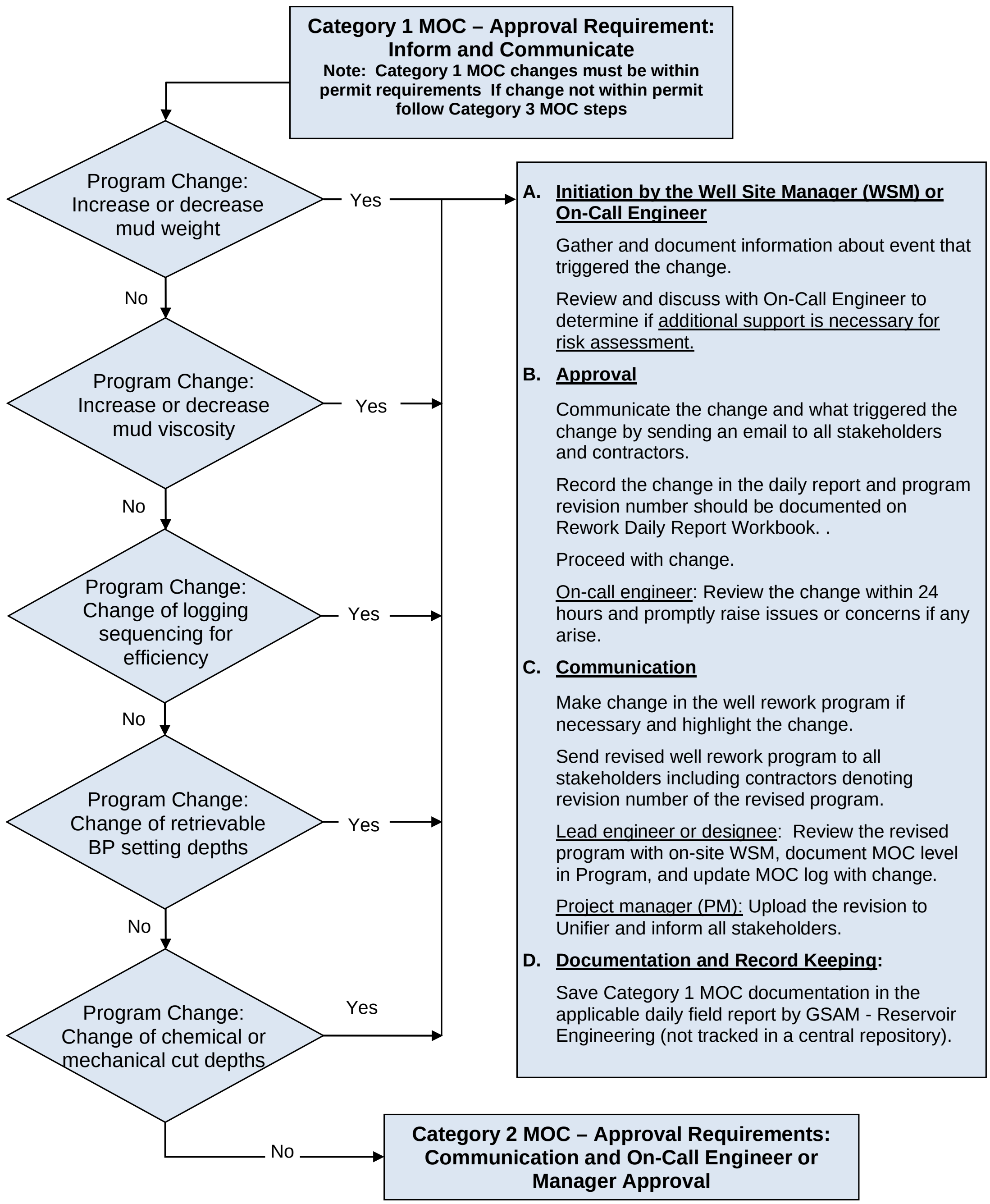
d. Project manager (PM): Upload the revision to Unifier and inform all stakeholders.

D. **Cat 1 – Documentation and Record Keeping:**

a. Save Category 1 MOC documentation in the applicable daily field report by GSAM - Reservoir Engineering (not tracked in a central repository).

Management of Change for Well Rework

Figure AC-1: Category 1 MOC Decision Flow Chart



2. Category 2 MOC – <u>On-Call Engineer or Manager Approval Required</u>

Director of GSAM may designate authority to other individuals for Category 2 MOC manager approval.

Certain event and/or step changes require communication and MOC approval during well rework and drilling operations, such as:

1) Change of logging depths
2) Change of under-reaming depths
3) Change of open hole sizes
4) Change of pipe recovery operation

Note: Category 2 MOC changes must be within permit requirements.

These event type changes will follow the Category 2 MoC process structure with the following steps:

A. Cat 2 - Initiation by the Well Site Manager (WSM) or On-Call Engineer

a. Gather and document information about event that triggered the change.

i. Review and discuss with On-Call Engineer to determine if additional support is necessary for risk assessment

ii. Notify Lead Engineer or PM&O Manager the change and communicate what triggered the change by sending an email to all stakeholders and contractors.

B. Cat 2 - Approval

a. On-call or lead engineer: Follow the field change control process for each documented change and complete the Well Work Field Change Control Form and document all actions triggered by the change.

b. Support with additional risk assessment activities and corresponding documentation if necessary

c. Obtain approval signatures from Lead Engineer, on-call engineer, or PM&O manager

d. <u>On-call Engineer</u>: Review the change within 24 hours and promptly raise issues or concerns if an arise.

C. Cat 2 – Communication

a. Make change in the well rework program if necessary and highlight the change.

b. Send revised well rework program to all stakeholders including contractors denoting revision number of the revised program.

c. Lead engineer or designee: Review the revised program with on-site WSM, document MOC level in Program, and update MOC log with change.

d. Project manager (PM): Upload the revision to Unifier and inform all stakeholders.

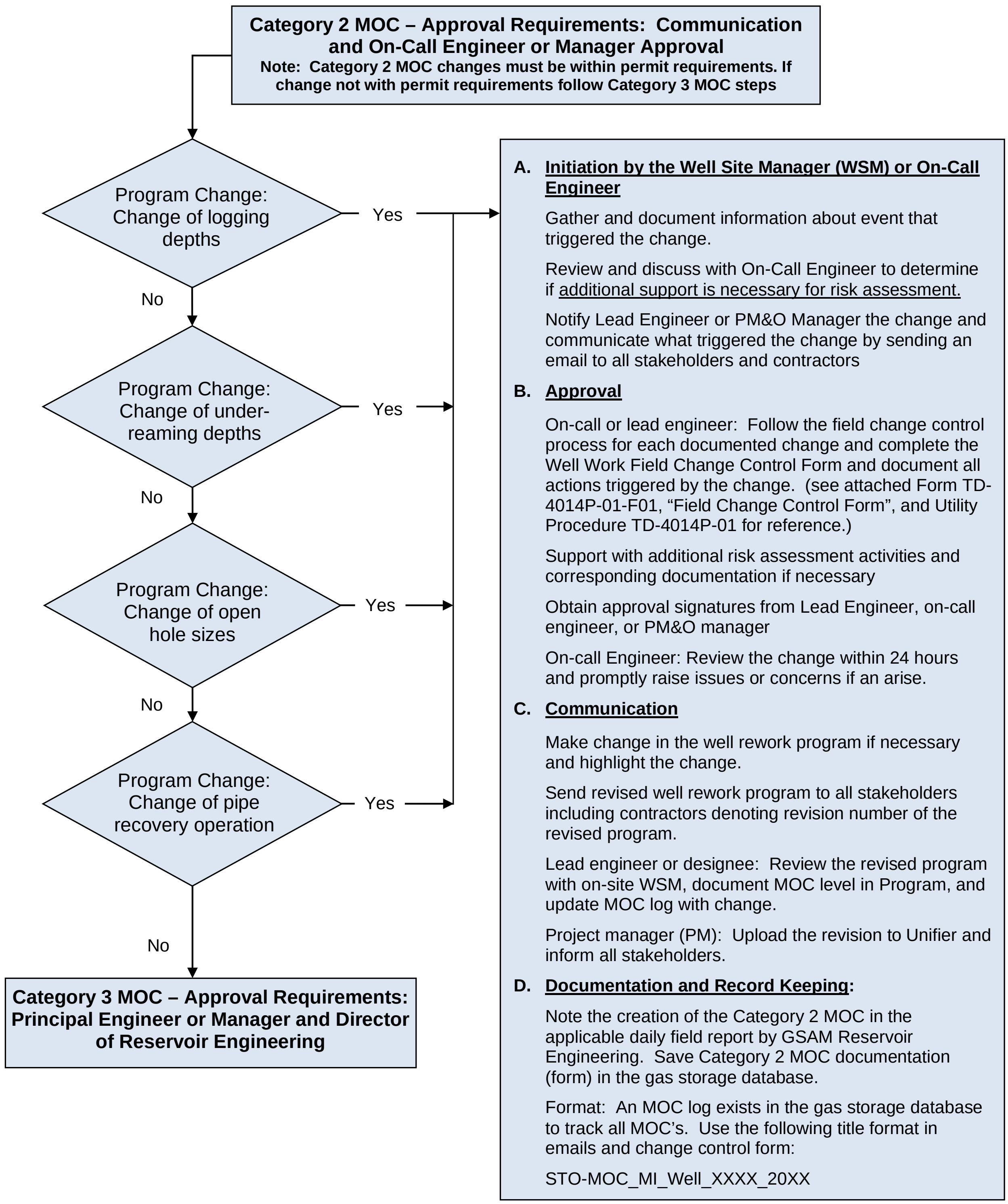
D. CAT 2 – Documentation and Record Keeping:

i. Note the creation of the Category 2 MOC in the applicable daily field report by GSAM Reservoir Engineering. Save Category 2 MOC documentation (form) in the gas storage database.

ii. Format: A MOC log exists in the gas storage database to track all MOC's. Use the following title format in emails and change control form: STO-MOC_MI_Well_XXXX_20XX

Management of Change for Well Rework

Figure AC-2: Category 2 MOC Decision Flow Chart



3. <u>Category 3 MOC – Approval Requirements: Principal Engineer or Manager and Director of GSAM</u>

Director of GSAM may designate authority to other individuals for Category 3 MOC approvals (either principal engineer or reservoir engineering manager or other approvals).

Apply the category 3 MOC process to certain events and/or step changes during well rework operation such as those listed below.

1) Changes that impact permits
2) Change of production casing setting depths during cementing
3) Change of production liner packer setting depths
4) Sidetrack
5) Abandon
6) Unplanned plug-back
7) Pipe or wireline stuck in the hole that requires backing or shooting off tools

These event type changes will follow a Category 3 MoC process structure with the following steps:

A. **Cat 3 - Initiation by the Well Site Manager (WSM) or On-Call Engineer**

a. Gather and document information about event that triggered the change.

i. Review and discuss with On-Call Engineer to determine if additional support is necessary for risk assessment and document

ii. Notify Lead Engineer or PM&O Manager of the initial risk assessment and send an email to all stakeholders and contractors.

B. **Cat 3 - Approval**

a. On-call or lead engineer: Follow the field change control process for each documented change through MoC process to complete the Field Change Control Form and document all actions triggered by the change. (see attached Form TD-4014P-01-F01, “Field Change Control Form”, and Utility Procedure TD-4014P-01 for reference.)

b. Support with additional risk assessment activities and corresponding documentation if necessary

c. Track changes through MoC process during the rework or drilling operations

Management of Change for Well Rework

d. Designate Project Management reservoir engineer and integrity management reservoir engineer as approvers in the approval process to endorse the initial change. Document the initial risk assessment

e. Engineer on Call or designee informs and consults principal engineer or Director of GSAM on approval process and provides Change Form.

f. Principal Engineer or Director GSAM: Provide final approval by performing the following:

i. Challenge the change and the change documentation, provide resources for change process, and approve the change before the change is implemented.

ii. Obtain signed approval of the Director on the Change Form TD-4014P-01-F01, “Field Change Control Form”

C. **Cat 3 – Communication of Change and Train Affected Personnel**

a. On-call Engineer or designee

i. review the change within 24 hours and promptly raise issues or concerns if an arise

ii. Make change in the well rework program if necessary and highlight the change.

iii. Send revised well rework program to all stakeholders including contractors denoting revision number of the revised program.

iv. Initiate personnel training for those individual affect by the change and document training records

v. Determine and document whether a PSSR or PHA will be needed, for example in situations where restart will be necessary.

b. Lead engineer or designee: Review the revised program with on-site WSM, document MOC level in Program, and update MOC log with change.

c. Project manager (PM): Upload the revision to Unifier and inform all stakeholders.

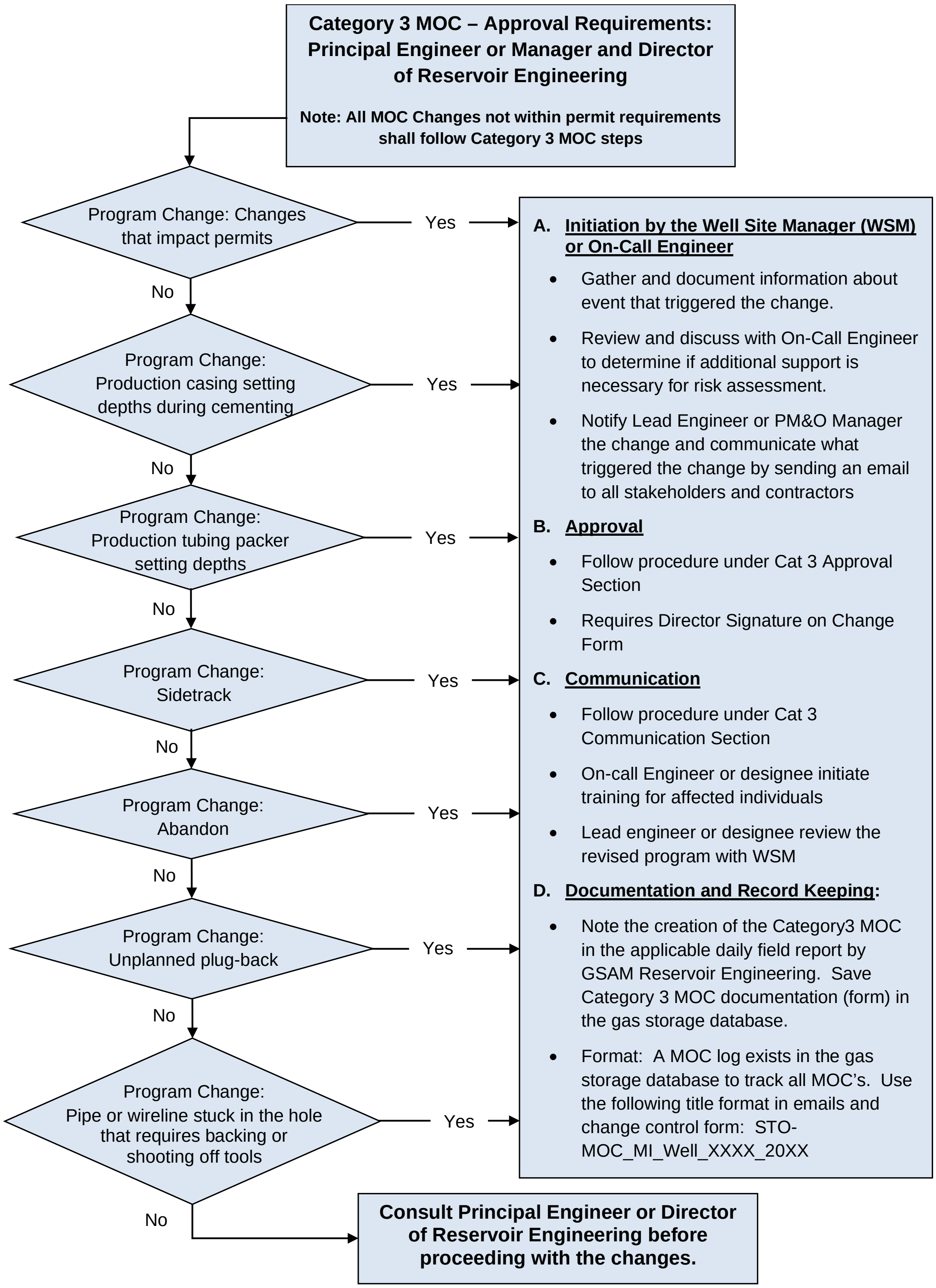
D. **Cat 3 – Documentation and Record Keeping:**

a. Note the creation of the Category 3 MOC in the applicable daily field report by GSAM Reservoir Engineering. Save Category 3 MOC documentation (form) in the gas storage database.

b. Format: A MOC log exists in the gas storage database to track all MOC’s. Use the following title format in emails and change control form: STO-MOC_MI_Well_XXXX_20XX

Management of Change for Well Rework

Figure AC-3: Category 3 MOC Decision Flow Chart



Management of Change for Well Rework

END of Procedure

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Director, GSAM

GOVERNING DOCUMENT

GSAM Standard 1, Storage Integrity Management

GSAM Standard 22, Management of Change

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1 Section 3

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

GSAM Standard 22, Management of Change

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces IMP Appendix AC, of the Underground Storage Risk and Integrity Management Plan, REV 5

Management of Change for Well Rework

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix AC to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Rig Evacuation Procedure

SUMMARY

Follow this procedure when a drilling rig must be evacuated.

TARGET AUDIENCE

Reservoir Engineering (RE)

GPOM

PG&E Safety and Environmental Department Personnel

Well site contractor employees

SAFETY

Follow the requirements in this procedure, the safety plan for well work and the facility safety guidance documents.

TABLE OF CONTENTS

Rig Evacuation Procedure

1. Procedure Steps

1. Set tool joint at rig floor & set slips	Driller & floor hands
2. Install full opening valve & close valve	Driller & floor hands
3. Shut in well with pipe rams & lock down rams a. Shut in well with blind rams if no pipe in hole b. Count the number of turns of both shafts and report it to the driller. c. Leave accumulator handle in the closed position	Derrick man
4. Secure all wing valves on mud cross & tree	Derrick man
5. Secure rig blocks	Driller
6. Shut down draw works, light plant & pump	Driller & derrick man
7. Evacuate all personal to muster station	

TWO LONG BLASTS = EVACUATION ALARM

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Reservoir Engineering, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

Rig Evacuation Procedure

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1, Section 3.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

Detailed Procedure: Utility Procedure: TD-4870P-01 Gas Well Wireline Procedure (Replaced TD-4550P-20)

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix AD in the Underground Storage Risk and Integrity Management Plan,.Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix AD to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Rig Evacuation Procedure

Safety and Environmental Plan – Well Entry Work

SUMMARY

This standard provides the requirements for safety and environment for all well entry work, including not only drilling and rework, but also wireline or other data gathering.

ACKNOWLEDGEMENT

PG&E and Contractor personnel are to review and understand the Safety and Environmental Plan as outlined in Form AE-1 below. PG&E should ensure personnel have signed acknowledging an awareness of the Plan and retain the signed Plan copies for the duration of the work activity it is intended to cover.

TARGET AUDIENCE

Gas Storage Asset Management

- Integrity management engineers
- Well work project managers
- Technical work supervisors

GPOM

Well work contractor personnel

SAFETY

This standard addresses safety. See Requirements below.

TABLE OF CONTENTS

Safety and Environmental Plan – Well Entry Work

REQUIREMENTS

1. Steps

1.1. PG&E and Contractor personnel are to review and understand the Safety and Environmental Plan as outlined in Form AE-1 below.

1.2. PG&E should ensure personnel have signed acknowledging an awareness of the Plan and retain the signed Plan copies for the duration of the work activity it is intended to cover.

1.3. Review and signing of the Plan can be used for multiple projects but should be reviewed and acknowledged annually.

1.4. Use of the local operations form or other format may substitute for Form AE-1.

1.5. Well Site Managers and GSAM should also refer to Procedure AM – PGE Well Site Manager and AG Guidance Document

2. GSAM FORM AE-1 Safety and Environmental Plan - Well Entry Work

Items not applicable to the location should be struck or added and then be initialed by PG&E representative

I <printed name>____have reviewed and acknowledge the Pacific Gas and Electric Underground Storage Facility Drilling/Rework Safety and Environmental requirements.

Signature:____Date:___________

- **Site Safety Plan Acknowledgement**
  - All Personnel: Prior to starting any work, read and sign the Site Safety Plan located at the PG&E job trailer.
- **Safety PPE Requirements**
  - The following Personal Protective Equipment (PPE) is required at all times while on jobsite.
  - Hard hats
  - Orange vests with reflective stripes
    - Not required while performing work on the rig floor.
  - Appropriate clothing with long sleeves
    - Coveralls with long sleeves and reflective stripes will be accepted in lieu of orange vests and long sleeve shirts. The FR is Federal OSHA requirement.
  - Safety glasses
  - Appropriate hearing, hand, and foot protection
- **Drilling/Rework Safety Requirements**
  - Attend site safety plan reviews and/or tailboarding meetings while on location.
  - Comply with all current API, CalGEM, Federal and California State and local OSHA safety regulations covering drilling rig, transportation, and equipment operations. (Contractors refer to your companies for these regulations.)
  - Abide to the Injury and Illness Prevention Program as specified in the current Federal, California State and Local OSHA or CalGEM safety regulations. (Contractors refer to your companies for these regulations.)

- Keep worksites clean and orderly at all times.
- Contractor: Inspect contractor personnel, equipment, and work site daily, and eliminate all Federal and California State and Local OSHA or CalGEM regulation violations, and any hazards that threaten the safety of personnel or well drilling and rework operations.
- Participate in blow out preventer (BOP) drills that will be performed at minimum once a week per crew, or right before drill out casing shoe, or as directed by PG&E representative(s).
- Ensure that all work areas are adequately illuminated.
- Smoking shall be permitted in Doghouse and Contractor’s trailers only. Properly dispose of butts.
- Chock or wedge all piping on storage racks, or secure otherwise to prevent it from falling or rolling off the rack.
- Do not “piggy-back” ride on forklifts or back of pick-up trucks at any time.
- Adhere to designated parking for rig crew as provided by PG&E.
- Do not park on the grass or off the roadway.
- Adhere to the road speed limit of 15 mph, and job site speed limit of 5 mph.
- Be mindful of cattle in the area.
- **<u>Do not use cell phones on the rig floor or around the wells</u>**.
- Report any unsafe situations to contractor supervisor and PG&E representative immediately.

- **Environmental Requirements**
  - Attend all environmental plan reviews and/or tailboarding meetings while on location
  - Contractors: Comply with all Federal and California State and Local EPA environmental regulations pertaining to notification, handling, storage, disposal, and transport of all hazardous or toxic substances.
  - Endangered Species may be present in the area. Notify the PGE Rep immediately if any of the species is thought to be present. Photos will be provided for the work site.
  - Contain and clean up all spilled materials or liquids immediately. Notify PG&E immediately of any spills.
  - Repair all leaks immediately - No fluids allowed on the ground.
  - Place all service equipment on top of plastic sheeting if there is potential for leaks or spills.
  - Drilling Company or other contractor: Perform hazardous checks daily. Correct any deficiencies immediately. Provide the PG&E representative with the drilling company daily check list.

- Store all hazardous materials properly and label and maintain all containers properly.
- Drilling Company or other contractor: Maintain weekly hazardous checklist, and provide copies provided to PG&E.

- **Housekeeping**

    - GSAM and contractor: Ensure that an emergency contact list is posted at the Dog House and the PG&E job trailer and that the Site Specific Safety Plan (SSPP) in possession of safety captain and well site manager.
    - GSAM and contractor: Ensure that directions to the nearest hospital are available at the Dog House and the PG&E job trailer.
    - PG&E and Contractor Personnel involved in well entry work: Sign in with the designated safety lead (safety captain for rig / wireline contractor) before working and sign out before leaving.
    - In case of an emergency or evacuation, all personnel will meet at a designated muster point established by local operations.

END of Form AE-1

Safety and Environmental Plan – Well Entry Work

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GSAM

GPOM

Contractor

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1 Section 3.

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Appendix AE of the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

Safety and Environmental Plan – Well Entry Work

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix AE to this standalone standard	Minor language changes were made for clarity. No content changes were made.

Well Signage, Gas Storage Wells

SUMMARY

This standard contains requirements for signage at PG&E's underground gas storage facilities.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM)

GPOM – maintain signage for wells

Corporate Security

SAFETY

n/a

TABLE OF CONTENTS

REQUIREMENTS

1. Inspection of Signage

1.1. Gas storage well signage should periodically be inspected that signage meets the general requirements below

1.2. If the signage is incorrect, damaged, or missing, the employee or contractor should notify GSAM. GSAM will take corrective actions to have the issue remediated.

2. General Requirements

2.1. Post signs in a conspicuous place

2.2. Use sign font and colors that are clearly visible and legible from a distance

2.3. Do not affix signs to wellheads to prevent bird nesting (no regulatory requirement exists that specifies signs must be on the wellhead).

2.4. Maintain signs during all construction activities with either permanent or temporary placement that meets the requirements states within this Standard AF

3. Single well site signage

The following information is required on signage if placed at a single well site (can be located on security fence or near wellhead)

3.1. Storage facility name

3.2. Lease/well name, and identification number

3.3. Operator name

3.4. Operator's 24-hour emergency contact number

4. Multiple well site signage

The following information is required on signage if placed at a well site with multiple wells

4.1. Signage Placed on security fence at entrance (information common to all wells)

4.1.1. Storage facility name

4.1.2. Operator name

4.1.3. Operator's 24-hour emergency contact number

4.1.4. Lease/ well name if similar for all wells on pad

4.2. Signage placement near wellhead

4.2.1. Lease/ well name (if differing for each well on pad)

4.2.2. Identification number

END of Requirements

Well Signage, Gas Storage Wells

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

GPOM

Gas Storage Asset Management

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in standard 1.

PHMSA requirements under 49 CFR 192.12 (API RP 1171 Section 10.4):

Permanent weatherproof signage shall be posted at each well site for identification purposes. The signs should contain the following information at a minimum

a) Storage facility name, well name, and /or identification number

b) Operator name

c) Operator’s 24-hour emergency contact number

CalGEM requirements: 1722.1.1. Well and Operator Identification

a) Each well location shall have posted in a conspicuous place a clearly visible, legible, permanently affixed sign with the name of the operator, name or number of the lease, and number of the well. These signs shall be maintained on the premises from the time drilling operations cease until the well is plugged and abandoned.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1

Supplemental References: Procedures referenced in the requirements section above.

- Gas Standard L-26, Underground Gas Storage Caution Sign
- Gas Standard L-51, Padlock Installation

Well Signage, Gas Storage Wells

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

This replaces Appendix AF of the Underground Storage Risk and Integrity Management Plan, REV 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM.

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix AF to this standalone standard	Minor language changes were made for clarity. No content changes were made

Well Work Requirements

SUMMARY

Well work programs are governed by the well work plans that are created as part of preparation for the well work. This standard provides the requirements for well work programs.

Work plans are created and used to help ensure the work scope and safety and environmental considerations are clear for all personnel involved, and to ensure that PG&E practices and requirement set forth in applicable Gas Operations and gas storage guidance documents are identified and followed. Work plans also help ensure PG&E and regulatory requirements are understood and followed during work on PG&E's underground storage wells.

Work plans shall be created when performing rework, wireline, slickline and logging operations, well testing and other well operations requiring well entry. Work plans incorporate PG&E practices set forth in this IMP.

Check list usage is recommended to reduce the human factor risk element in the operation and maintenance of the assets.

TARGET AUDIENCE

Gas Storage Asset Management (GSAM), Reservoir Engineering group (RE)

Well work contractors

Gas Pipeline Operations and Maintenance (GPOM)

TABLE OF CONTENTS

Well Work Requirements

1. General Requirements

The work plan for a specific well identifies site-specific requirements, and accounts for hazards and conditions expected to be encountered in the well.

1.1. Provide copies of appropriate checklists and guidance documentation to contractors, review those documents with contractors prior to any work being performed, and ensure that persons performing work in the storage field are familiar with the documents and record keeping requirements.

1.2. Provide training to contracted personnel that includes applicable site-specific safety procedures, awareness of rules pertaining to the facility, reporting requirements and the applicable provisions of emergency action plans.

1.3. Supervisor Span of Control: Confirm with contractor supervisor that supervisor is responsible for training and confirming that

1.3.1. contractor personnel on site can recognize abnormal operating conditions, applicable hazards and know their role in safety and emergency procedures.

1.3.2. contractor personnel conducting gas storage well and reservoir operations are qualified to perform the work.

1.4. Conduct inspections of adjacent active and plugged wells during or following well work to verify integrity maintenance when a well located within the reservoir area and buffer zone is being treated at pressures exceeding maximum storage reservoir pressure.

1.5. Reviews of project details described in sections below should not be limited to a single review but as needed to address

1.5.1. personnel changes,

1.5.2. the risks and hazards associated with the work

‘

2. Flaring

The work plan for a specific well identifies site-specific requirements, and accounts for hazards and conditions expected to be encountered in during flaring operations

2.1.1. review of the flare operations communication plan and set up of the flare equipment is not located near any permanent or temporary vent stacks

2.1.2. communication plan with Operations on the start and commencement of flaring operations

3. Minimum Safety Requirements

3.1. Address the minimum safety requirements associated with the following in the well work program document:

- Surface equipment
- Pressure control equipment ratings for the maximum anticipated surface pressure to be encountered during the operation.
- Procedures, check lists if appropriate, and requirements to verify that equipment used for pressure control is in good operating condition and suitable for the intended operation
- Downhole operations
- Management of change processes – Refer to Procedure AC22, Management of Change
- Elements of process safety management
- Other requirements as specified by regulations and PG&E.
- The pressure rating of blowout preventers and ancillary pressure control equipment is suitable for the application.

3.2. A person who is qualified in well control, or knowledgeable, skilled and capable through experience to perform well control duties, shall be on site at the well during active drilling, completion, servicing and workover operations.

4. Well Work Program Kickoff

Because contractors have so many employees on site, communicating this information to all employees is a detailed and involved process. The kickoff meeting should address and strive to meet the objectives as summarized as follows:

OVERVIEW OF OBJECTIVES

1. Convey **safety and environmental** performance is of the highest priority. Confirm contractors are clear on PG&E's expectations in these areas.
2. Clarify and communicate roles and responsibilities of key project team members and include live introductions of key personnel when possible:
   - PG&E team (e.g., GPOM, environmental, safety, GSAM.
   - Contractors during the work.
3. Review detailed requirements of the contractors (PPE, JSA, reporting, personnel….etc.)
4. Review project details
   - Scope, schedule, CalGEM requirements
   - PG&E policies such as AOC, MoC
5. Review what has changed for the current year relative to prior years.

4.1. Safety & Environmental

4.1.1. Identify safety and environmental contact information

4.1.2. Other Requirements

SAFETY

1. ISNetworld (ISN). This system is a requirement for contractors and subcontractors on the project team.

   Contractors and subcontractors performing medium and high risk services for PG&E must maintain an active ISN subscription, in compliance with PG&E's contractor safety program.

   Contractors must ensure contractor employees have ISN Badges when working on PG&E Projects.
2. Plans

   a. Contractor site-specific safety plan (SSSP)
      - Contractors must submit an SSSP to GSAM PM
      - PG&E Safety Department must approve the SSSP in advance of commencement of work,

- o Contractors must maintain the SSSP on hand when work is underway.

b. Contractors must develop and maintain a first aid plan on hand when work is underway.

c. Contractor job safety analysis (JSA).
- o Contractors must conduct an initial JSA to identify known and potential job site hazards prior to starting any work.
- o Contractors must ensure that all personnel involved in the task are tailboarded on the JSA in advance of performing the work.
- o Contractors must update the JSA and tailboard the changes in the event of any significant change in task or the identification of unmitigated hazards.
- o Contractors must remove or mitigate known hazards by engineered controls when practical.

d. Contractors must develop rig layout and sizing plans prior to mobilization.

e. PG&E must provide contractors with information specific to the facility such as evacuation plans,

3. Reporting and communication requirements, incident reporting

a. Well site manager must provide a daily report to GSAM that includes
- o Incidents and abnormal operating conditions (IMP Standard 18, Abnormal Operating Conditions).
- o Briefings of work plans with the PG&E site lead

b. Well site manager must provide an IMMEDIATE report to the PG&E on-site Representative for:
- o All injuries, incidents, near-miss events, hazardous material and hazardous waste spills.
- o Initial reporting may be completed by phone, followed by a written report. A detailed written report within 24 hours of the incident may be required t of the contractor by the PG&E representative.

c. PG&E must provide contractors with
- o Communication plans with the control room
- o PG&E communication channel procedures (e.g., well work contractor to PG&E site lead to facility control room, use of UNIFIER document application)

4. EE training/documentation requirements, including contractor competency, training and personnel records requirements in GSAM Procedure AH, Well Work Contractor Competency.

5. Contractors shall be responsible to have an appropriate number of trained first aid persons on-site.
6. Hot work procedures.
7. Sling inspection requirements.
8. Gas monitoring requirements.
9. Fire index resources/notifications available to the contractor.
10. Storage and delivery of materials, including pipe loading and unloading,
11. Requirement that the contractor know weight limits of material and equipment to be transported and delivered, and lifting limitations of contractor equipment. This includes weight limits of cranes, private and public roadways, trailers, bridges, slings, shelves, and racks.
12. Requirement for mitigating hazards
13. PG&E's process for periodic inspection on site by PG&E safety SMEs of contractor activities

ENVIRONMENTAL

1. Requirements to participate in PG&E’s compliance and stewardship
2. Stop work authority - All employees, PG&E and Contractors are authorized and encouraged to “Stop Work” for any safety and/or environmental related issues.
3. Environmental procedures and issues associated with the work scope of the site that have been verified to minimize environmental risks, and PG&E's process for periodic inspection on site by PGD environmental SMEs of contractor activities.
4. Housekeeping
5. Environmental awareness – incident and release observation and reporting requirements - see something / say something.
6. Air quality - reporting on portable equipment on site to PG&E and to local air board (such as internal combustion engines).
7. Hazardous materials management including proper labeling of all material and equipment on site.
8. Hazardous waste management
9. Rework fluids management
10. Spill prevention and spill management

4.1.3. Employee safety and environmental items.

SAFETY

1. Safety expectation
2. Stop work
3. Evacuation plans
4. Other plans (e.g., SSSP, JSA, first aid)
5. Safety awareness - incident observation and reporting - see something / say something.
6. Conduct
7. LOTO
8. Housekeeping
9. Smoking
10. Cell phones
11. Driving: road rules, traffic congestion locations, backing & parking
12. PPE
13. Gas venting
14. Sling inspections
15. Site security policies
16. General safety rules (meeting points, off limit locations)
17. Incident history / types / log review and past safety observations

ENVIRONMENTAL

1. Air quality - reporting on portable equipment such as internal combustion engines on site to PG&E and to the local air board.
2. Hazardous materials management, including proper labeling of all material and equipment on site.
3. Hazardous waste management.
4. Environmental awareness - incident observation and reporting. See something / say something.

4.2. Review definition, recognition, response and documentation of abnormal operating condition with PG&E and contractor personnel

4.3. Review definition, recognition, response and documentation of Management of Change for well work with PG&E and contractor personnel.

5. **Program Review**

Program shall be reviewed with contractors who will be involved in or onsite during well entry work including rework, wireline, slickline and logging operations and should include the following items:.

This is typically reviewed in a meeting with contractors and PG&E project personnel after final permit approval by CalGEM to be sure all contract and PG&E personnel understand final scope and requirements, and to explore whether attendees can provide further input into the project plans and procedures.

- Well configuration and completion details.
- Characterization of the stored hydrocarbons and the presence of hazardous or corrosive agents.
- If necessary, review anticipated wellbore and storage zone pressures and temperatures.
- Anticipated presence of water, fluids, deposits or scale and restrictions in the wellbore.
- Reporting requirements, including that contractor personnel understand and adhere to reporting requirements in the operator's procedures.
- NOI permit requirements.
- Ensure that all permit requirements are reviewed with all vendors.
- Confirm that the contractor participated in the kickoff session(s) (Section 3 above).
- Rig mobilization plan and auxiliary equipment layout plot.
- Abnormal operating condition notification and documentation.
    - Requirement that contractors must notify PG&E of all incidents or injuries immediately. Notification must occur and a follow up report must be received within 24 hours of the incident.
    - Requirement that AOCs in general are to be documented in the daily well work report by the well site manager.
- Review and confirmation that PG&E has assessed the qualifications of the contractors' lead personnel involved in and around well entry work
- Procedure requirements for securing of wellhead upon demobilization (i.e., all vales closed, flanges, bullplugs, needle valves, clearances, pressure taps are accessible, wellhead orientation, and well signage (Standard AF, PG&E Underground Storage Facility Signage).

6. **On Site Kickoff meeting for work execution**

Review on site with rig crews and other contractor personnel who will be working on site before the commencement of work and the following should be reviewed:

This is typically conducted in meetings on site with all field personnel before the start of work.

Contractors should bring as many field personnel as possible to the initial session, and the remaining personnel will then meet on site in a subsequent session.

- Site-specific safety plan including JSA (job safety analysis created by the contractor and signed by all personnel prior to commencement of work by that person)
- Orientation training.
- Lockout tagout (LOTO) procedures employed by PG&E on site, and training delivered by PG&E Gas Contractor Safety Program Management.
- Facility evacuation procedures.
- Rig evacuation procedures.
- Communication protocol between contractors, site lead and facility control room.
- Site specific safety and environmental training.
- Requirements for daily tailboard.
- Requirement for the well site manager to provide a daily report to GSAM, including AOCs.

7. **Well Work Program Document**

This section describes conditions, objectives, procedures and cautions relative to work planned for a specific well and reviewed with appropriate contractors prior to mobilization.

A well work program document shall be created for each well work project.

A written program shall be completed and approved prior to mobilization of equipment onto the well. In the event of an emergency, work may commence prior to a completion of a written program.

7.1. The well work program document shall contain the following:

- Rig mobilization plan and location preparation plan
- Well work plans and work scope
- Pressure rating of blowout preventers and ancillary pressure control equipment
- Requirement for verification and documentation that blowout preventers are in good working condition and have been tested after installation

- Requirement for the confirmation that the blowout preventer position or state is as it should be at all times during the work.
- Site-specific requirements and plan elements that account for hazards and conditions expected to be encountered in the well.
- Explanations and procedures associated with operating conditions and activities where pressure control equipment is required.

7.2. Review recent well work program documents.

Previous well work program documents developed by GSAM SMEs are valuable templates for the preparation of new well work program documents and shall be reviewed when developing new well work program documents.

7.3. Include technical peer review

Employ technical peer review from a GSAM SME prior to finalization of well work program documents.

END of Requirements

DEFINITIONS

IMPLEMENTATION RESPONSIBILITIES

Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in standard 1.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix AG in the Underground Storage Risk and Integrity Management Plan, 7/10/20 rev 6a.

DOCUMENT APPROVER

Brad Carr, Manager, RE Storage Projects, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM

DOCUMENT CONTACT

Joe Chan, Reservoir Principal Engineer, RE Storage Projects, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix AG to this standalone procedure	Revision of organization and order were made for clarity. No content changes of significance were made

Well Work Contractor Competency

SUMMARY

This procedure addresses PG&E's policies and procedures regarding requirements in the PHMSA Final Rule (CFR 192.12 API 1171 Scn 11.13.2) for the competency of contractors engaged in well work for PG&E.

TARGET AUDIENCE

Storage asset family reservoir engineers, project managers and supervisors

GPOM personnel

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TABLE OF CONTENTS

SUBSECTION TITLE PAGE

STEPS / REQUIREMENTS

1. Pre-Work Procedures

In advance of performing work on PG&E storage field wells, the following processes are employed to ensure contractor competency.

1.1. Contractor safety performance record

PG&E Contractor Safety Program: This work is covered within the scope of PG&E's enterprise contractor safety program as outlined in the Contractor Safety Standard, SAFE-3001S. Prior to contracting with service providers for well work, perform a review of the contractor safety record and confirm that contractor meets PG&E's qualification requirements.

1.2. Contractor technical capabilities

GSAM: Prior to contracting with service providers for well related work, perform an assessment of the technical capabilities of the contractor relative to the GSAM scope of work. This may include

a. review and assessment of prior GSAM experience with contractor.
b. discussion and assessment with other clients of contractor regarding past work performed by the contractor.
c. Review and assessment of contractor corporate and personnel qualifications (see Section 1.3 below)

Perform assessments with respect to the following criteria. Gas Storage Asset Management personnel familiar with the related work along with the GSAM director approval may vary from these criteria:

a. Contractor has developed and implemented training programs that cover each applicable section identified in the Contractor Training Matrix (Matrix).
b. Contractor has provided signed acknowledgement of the required training for the GSAM scope of work, as outlined in the Matrix, dated less than one year from commencement of work. Signed acknowledgement of Matrix requirements are stored in the GSAM drive under ‘Contractor Support (Reworks)’ (see Section 1.3 below).
c. Widely recognized by gas well operator SMEs as a competent service provider, as determined by GSAM SMEs during interaction with other operators and Manager or Director approval has approved provider.

Criteria used will vary based on work scope and shall be documented by GSAM as part of this assessment.

GSAM and project managers: Document assessments performed of contractor capabilities in the GSAM drive under ‘Contractor Support (Reworks)’ or other designated records database.

Once such assessments are performed, GSAM may exercise discretion regarding whether or not to perform supplemental assessments when the contractor is considered for work in the future. Document the decision in the GSAM drive under ‘Contractor Support (Reworks)’ or another designated records database.

1.3. Contractor personnel qualifications and experience

GSAM SMEs and project managers:

Prior to contracting with service providers for well related work, perform an assessment of contractor training programs. Service providers are to review the required training content set in the Contractor Training Matrix, including corresponding API standards and specified PG&E RIMP documents, and acknowledge that their training programs address the required content. Contractors shall review the specified content in the Matrix, evaluate their training programs against the Matrix, and provide signed acknowledgement of compliance on an annual basis.

Perform assessments of key contractor personnel such as well work contractor operations manager, blowout prevention equipment operator, and well site manager with respect to the following criteria. GSAM SMEs with GSAM director approval may vary from these criteria:

a. Minimum experience performing applicable work in the gas well industry, including well work and well control procedures.

b. Technical education/training relative to competency in the GSAM work scope.

Criteria used will vary based on work scope and shall be documented by GSAM as part of this assessment.

Document assessments performed of contractor capabilities in GSAM shared drive "Contractor" folder under the relevant rework program year. Corresponding conclusions are documented in EDRS by the GSAM project managers and routed for approval through the director of GSAM, as applicable.

Once such assessments are performed, GSAM may exercise discretion regarding whether or not to perform supplemental assessments when the contractor employee is considered for work in the future. Document the decision in the GSAM shared drive "Contractor" folder under the relevant rework program year.

1.4. Contractor personnel training program

GSAM:

Prior to contracting with service providers for well related work, perform an assessment of the training program and curriculum in place for personnel to be employed by the contractor. Confirm that the training program content is satisfactory for the GSAM work scope, and includes the minimum requirements set in the Matrix. Criteria used will vary based on work scope and shall be documented by GSAM as part of this assessment.

Document assessments performed of contractor training program in the GSAM drive under 'Contractor Support (Reworks)' or other designated record database.

Once such assessments are performed, GSAM may exercise discretion regarding whether or not to perform supplemental assessments when the contractor is considered for work in the future.

1.5. Contractor personnel training documentation

GSAM:

Prior to contracting with service providers for well related work, GSAM may choose to obtain and assess documentation for training of personnel planned to be involved in the GSAM work scope, to confirm the appropriate contractor training has been completed.

Decide for each contractor whether to include requirements in contract terms that the contractor must provide to GSAM a roster of all personnel expected to be on site, and training records for all such personnel if requested. These requirements may include the following:

- Training records for personnel who have been identified by contractor in advance of commencement of work are to be provided by the contractor to GSAM prior to commencement of work.
- Contractor must confirm complete training records for personnel who begin work on PG&E's jobsite after the initial commencement of work shall be delivered to the GSAM leadership or project management.
- PG&E's GSAM leadership or project manager will rely on the contractor to ensure that the personnel provided by the contractor for work on PG&E sites have received appropriate training under the contractor's training program.

ON-THE-JOB TRAINING EXCEPTION - Contractor personnel who are receiving training while working on the job will be accepted without the advance training and corresponding records described above, as long as such personnel are working under the direct supervision of the contractor well work lead already approved by GSAM.

Document GSAM assessments performed of contractor training records in the GSAM shared drive. Retain contractor personnel training records provided by the contractor in the GSAM shared drive “Contractor” folder under the relevant rework program year.

GSAM may elect to perform supplemental assessments of training records for personnel previously assessed by GSAM when the contractor is considered for work in the future.

1.6. Contractor Site Safety Plan Review

The contractor submits a site safety plan to the well work project management or directly to PG&E’s Gas Contractor Safety Program Management (GCSPM).

GSAM: Perform a review and assessment in conjunction with GCSPM. Upon review and approval by both project management and GCSPM, the plan document is retained by the contractor and by GCSPM on site.

1.7. Contractor drug and alcohol testing program

PG&E contract general conditions require that contractors comply with PG&E’s drug and alcohol abuse and testing policies, set forth in PG&E’s contract general conditions.

Well Work Contractor Competency

2. Procedures during Well Work

Employ the following procedures during the performance of work on PG&E storage field wells to support ensuring contractor competency.

2.1. PG&E site and job specific training.

PG&E Gas Contractor Safety Program Management (GCSPM), GPOM and GSAM:

Conduct an orientation kickoff meeting on site in advance of the commencement of work addressing safety and work scope. A written script/checklist is used to confirm all issues are covered. This includes

- Pre-startup safety review (PSSR) led by either GSAM or GCSPM. PSSR document is retained Unifier per TD-4006S.
- Training regarding notification processes and circumstances for communications with on-site GPOM control room personnel communication path is:
  - Contractor’s well work supervisor to the PG&E site manager, to the storage field control room, or
  - Contractor’s well work supervisor to the contract site manager, to GSAM to the storage field control room
- Lockout/tag out awareness training is provided through GAS-0867 and training delivered by GCSPM.
- Abnormal operating condition awareness. Ensure that responsibilities are clear that supervisors of well work must confirm that personnel on site can recognize abnormal operating conditions, applicable hazards and know their role in safety and emergency procedures.
- Abnormal operating condition notification and documentation. Contractors must notify GCSPM of all incidents or injuries immediately. Notification must occur to both WSM and GCSPM and follow up report must be received with 24 hours of the incident.
- Rig evacuation procedure - GSAM Procedure AD – Rig Evacuations.
- Facility evacuation guidance document.
- Project technical work scope kickoff briefing (GSAM project work plan),
- Applicability of well work management of change (GSAM Procedure AC – Management of Change).

Documentation that this training occurred is retained by GPOM in the project file or by GCSPM in its project files.

Any contractor personnel new to the site who have not gone through this training shall be given a job safety assessment (JSA) by the contractor prior to commencement of work by that individual.

2.2. Contract personnel identification/records.

Contractor is required to confirm personnel have the required training and are competent per the PG&E Contractor Training Matrix.

When new contractor personnel are brought on site by the contractor, they become part of the job site roster when they sign in when they are briefed on the JSA. Training records are delivered by the contractor to the site lead as described in Section 1.5 above.

GSAM: PG&E or contract personnel with site lead responsibilities shall confirm that contractor training records are in GSAM's files on site for the contractor personnel on the roster provided by the contractor, or that the new personnel are receiving OJT and have no training records, or incomplete training records. PG&E shall rely on the contractor to keep the contractor personnel roster held by the PG&E site lead current.

2.3. Technical peer review of contract personnel technical performance.

GSAM: Conduct periodic inspections of contractor well related work to assess the competency of contractor personnel in the performance of GSAM's work scope. Include abnormal operating conditions both encountered and possible, as well as the understanding of the GPOM site safety procedures including control room interaction. Assess contractor work quality and personnel competency. Assess the implications of the frequency of periodic inspections and vary the inspection frequency accordingly.

Inspections and assessments performed of contractor capabilities shall be documented by GSAM in the job file.

2.4. Technical peer review of contract personnel environmental performance.

PG&E Environmental Management Department: Conduct periodic inspections of contractor well related work to assess the competency of contractor personnel in the adherence to environmental requirements associated with GSAM's work scope, in accordance with Environmental Services procedure ENV-10000S Environmental Release to Construction (ERTC) for Land and Environmental Evaluations.

Inspections and assessments performed of contractor capabilities shall be documented Salesforce, the electronic records system used by PG&E Environmental Management.

Well Work Contractor Competency

2.5. Technical peer review of contract personnel safety performance.

GCSPM: - Conduct inspections of contractor well related work to assess the competency of contractor personnel in the adherence to safety requirements associated with GSAM's work scope. This includes:

- Conduct daily observations (sometimes with a contract inspector) and document observations in “IAuditor”, the electronic tool used by GCSPM for capturing such documentation.
- Provide observations to contractor by email.
- Provide weekly report on observations including an overall summary of what was observed that week, and whether open issues need to be addressed.
- Conduct a modified PSSR developed with Process Safety Department, as an inspection once the rig in place before fluid is introduced. Document in the IA tool.
- Conduct a modified PSSR developed with Process Safety Department, as an inspection for flaring operations. Document in the IA tool.

END of Requirements

DEFINITIONS

IMPLEMENTATION RESPONSIBILITIES

Lead engineer, Integrity Management Group, Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard AG – Well Work Requirements

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1

Supplemental References:

n/a

Well Work Contractor Competency

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix AH in Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix AH to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Rathole Drilling Program

SUMMARY

Purpose:

This procedure provides guidance for the provision of a storage place for the Kelly, consisting of an opening in the rig floor fitted with a piece of casing with an internal diameter larger than the outside diameter of the kelly, but less than that of the upper kelly valve so that the kelly may be lowered into the rathole until the upper kelly valve rests on the top of the piece of casing. This hole is in the floor of the rig, bored into the earth for a short ways, and usually lined with a metal casing known as a scabbard.

TARGET AUDIENCE

All are responsible for pre-job planning, safety meeting, and assigning personnel to perform rathole drilling execution and monitoring functions.

PG&E Reservoir Engineering

PG&E Well Rework Supervisor

PG&E District/GC personnel

Drilling Rig Representative

Rathole Drilling contractor

SAFETY

Follow the requirements in this procedure, the safety plan for well work and the facility safety guidance documents.

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Rathole Drilling Program

1. General Requirements

1. Wellsite manager and GSAM engineer:
   - Consider the following actions for the PG&E gas storage rework "Rathole Drilling" operation and adjust based on well pad conditions, offset work activities, and risk and hazards to complete work.
   - Include a detailed rathole drilling program in the well program.

The following actions should be considered for the PG&E gas storage rework "Rathole Drilling" operation and should be adjusted based on well pad conditions, offset work activities, and risk and hazards to complete work. The well program should include a detailed rathole drilling program.

The engineer and/or the WSM shall specify the responsible party for each of these actions:

2. At least 14-20 days prior to drilling rathole, meet onsite to discuss and mark rathole location.
3. Rework well has been cleared and flow arms removed.
4. Make USA (Underground Service Alert) notifications.
5. Notify drilling mud contractor and vacuum truck service to have sufficient drilling mud on site for rathole drilling to support this program. (McDonald Island only)
6. Ensure weather, and environmental conditions are appropriate before initiating Rathole Drilling Program. If not, postpone until they are favorable.
7. Hold a pre-job Safety Tailboard on this subject.
8. All ensure that all are in agreement that the location is acceptable before attempting to drill rathole.
9. Obtain hot work permit.
10. Pothole location to a depth not less than 6' deep (refer to TD-44412P-05 section 6.0 Critical Facility).
11. Rig up rathole drilling contractor.
12. Commence drilling rathole and adding drilling mud as needed to keep the hole lubricated and from caving in.
13. Install scabbard (metal casing) after proper depth is reached.
14. Rig out rathole drilling contractor.
15. After completion of rathole drilling clean and remove drilling spoils from the area, cover rathole and barricade the area.

16. Backfill rathole with sand.
17. Rathole drilling program complete.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1

Standard AN, Well Control

Standard AG, Well Work

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

Rathole Drilling Program

DOCUMENT RECISION

The replaces Appendix AI in the Underground Storage Risk and Integrity Management Plan, rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix AI to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Well Kill Program

SUMMARY

Purpose:

This document provides an overview of the well kill operation which is the first step in reworking a producing well. The well kill operation is the process to pump kill fluid of sufficient weight to eliminate formation pressure and allow for wellbore intervention operations to proceed. The primary method for killing the producing well for well rework operation is through its production tubing as described in the steps noted in this document.

Proper considerations must be given to the selection and type of kill fluid, formation characteristics and pressure, tubing and casing integrity, and the ability to circulate when selecting an appropriate method of killing a well.

TARGET AUDIENCE

Reservoir Engineering

PG&E Well Site Supervisor

PG&E Gas Construction Team

Drilling Rig Supervisor and Team

Other Contract personnel.

All entities are responsible for pre-job planning, safety meetings, and assigning personnel to perform the execution and monitoring functions of this program.

Updates to this procedure may be necessary due to changes in Facility, Operational needs or permit requirements.

TABLE OF CONTENTS

1. General Requirements

Before performing the following steps, certain actions must be taken to ensure the well kill is performed in the safest and most efficient manner possible. The following actions are typically utilized for PG&E Gas Storage “Well Kill” Operation. Changes to the procedure below may be needed to due to changes in facility and well configurations.

Well Kill Program shall be approved and included with well work program if modified from the steps included in this Procedure

2. Before the Start of a Well Kill

PG&E well site supervisor has the overall responsibility for the completion of the following tasks

PG&E Gas Construction (GC) and drilling rig personnel are responsible for the tasks involved under supervision.

All personnel on site are responsible to ENSURE safe work practices

2.1. NOTIFY Operations Department to initiate flaring notifications request at least 24 hrs. before flaring / venting.

2.2. CONFIRM that the flare stacks are not located near any permanent or temporary vent stacks

2.3. CONFIRM with Operations that the flaring notifications have been made. IF there is a change in date, provide Operations with advance notice.

2.4. HOLD pre-job safety tailboard on well kill operation.

2.5. INPUT rework well data for kill calculation. refer to well kill spreadsheet.

2.6. RECORD rework well shut in tubing and casing pressures.

2.7. ENSURE weather and environmental conditions are appropriate before initiating Well Kill. IF not, postpone until the conditions are favorable.

2.8. ENSURE sufficient volume of kill fluid is on site to support well kill operation.

2.9. CONSULT with engineering team regarding field conditions (i.e., low pressure) if appropriate mix materials are required to be on site to increase mud viscosity should a pill be needed during the kill operation.

2.10. FILL RIG PITS WITH KILL FLUID. Mud engineer and rig supervisor to confirm that the kill fluid in the rig pits meets all specifications.

2.11. NOTIFY Operations to check the flaring area at least 4 hours prior to flaring/venting and issue hot work permit.

2.12. INSPECT that all piping connections, fittings and valves are tightened and in good condition.

2.13. GC: Run temporary 2" gas (high pressure) piping from rework well casing wing valve to the PG&E Kill Manifold and Contracted permitted Flare/Separator Equipment, Half-Round, and Rig Pits.

3. Preparation to Pressurize Piping/Equipment and Testing

- ***Wells with DHSVs installed**:* Perform all steps.
- ***Wells with no DHSVs installed*: ** Omit the following items in Step 3 (5 through 9).

3.1. CONNECT rig pump discharge line to the well tubing connection on the rework well.

3.2. ENSURE the Rig Supervisor has set up valves in the correct position from the rig pumps to the well tubing connection.

3.3. PRESSURE TEST rig pump discharge line between rig pumps and wellhead. Start pump and pressurize to 2000 PSIG and check for leaks. If leaks are found, make repairs and retest as necessary.

3.4. NOTIFY Operations to Report On "Test" on rework well.

3.5. INSTALL pressure gauge(s) to obtain rework well Tubing and Casing Shut-in pressures above the DHSV(s). If pressure differential between Tubing and/or Casing Shut-in pressures and Field pressure is >100 PSIG, pressures must be equalized. Ensure pressures are within acceptable (~100 psi range) before attempting to pump hydraulic fluid.

3.6. ENSURE air supply from drilling rig is adequate and readily available. CONNECT air hose to the pneumatic hydraulic pump air inlet.

3.7. CONNECT hydraulic pump hose to the DHSV connection on the rework well.

3.8. PUMP hydraulic fluid up to 4500 PSIG to OPEN DHSVs on the rework well. Acceptable limits are within 4000-4500 psi. VERIFY DHSVs OPENED.

3.9. CONTINUOUSLY MONITOR and maintain up to 4500 PSIG on the DHSV hydraulic control line.

3.10. ENSURE all three Gate Valves are closed on the Kill Manifold.

3.11. ENSURE “Rework Well” wellhead valves are closed. SLOWLY OPEN casing wing valve to obtain gas pressure and check for leaks. CHECK LEAKS on all fittings and connections by SOAP TESTING.

3.12. PRESSURE TEST all gas piping including contractor’s permitted flare equipment between the PG&E Kill Manifold and Outlet of their separator skid. PRESSURE TEST in two steps below.

3.12.1. Step 1: Test to 100 PSIG. If LEAKS are found, bleed all gas piping including contractor’s permitted flare equipment to 0 PSIG. FLARE as directed. Follow the clearance process to FIX any LEAKS before proceeding.

3.12.2. REPEAT Step 1 as necessary until all leaks have been repaired, then proceed to Step 2.

3.12.3. Step 2: Test to AVERAGE FIELD PRESSURE. RAISE Pressure in increments until it reaches average field pressure. If LEAKS are found, bleed all gas piping including contractor’s permitted flare equipment to 0 PSIG. FLARE as directed. Follow the clearance process to FIX any LEAKS before proceeding.

3.12.4. REPEAT Step 2 as necessary until all leaks have been repaired. THEN proceed to VENT ALL GAS DOWNSTREAM OF THE KILL MANIFOLD.

4. Pumping Kill Fluid

4.1. INSTALL pressure gauge on the kill manifold to monitor the casing flow pressure during the well kill operation.

4.2. ENSURE stroke counter is set to zero and is functioning properly.

4.3. MONITOR rig pumps strokes per minute as initiated by Reservoir Engineering Rework Supervisor. Consult the Rig Supervisor on final number.

4.4. SLOWLY OPEN casing wing valve to Kill Manifold. Kill Manifold gauge should read field pressure.

4.5. BEGIN PUMPING kill fluid down the tubing and while simultaneously opening Master Gate Valve slowly.

4.6. MAINTAIN pump rate while adjusting kill manifold choke valve to bleed off casing gas pressure as per Kill Sheet.

4.7. When fluid reaches surface, TRANSFER RETURNS to the rig's pits and continue circulating until fluid is relatively free of gas.

4.8. STOP PUMPING to verify the rework well is STATIC. Zero pressure on tubing/casing indicates well is full of kill fluid. Well is now safe to install back pressure plug.

4.9. REMOVE clearance from the rework gas well.

4.10. Well kill operation is completed.

4.11. VERIFY volume and note any fluid losses.

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1

Standard AN, Well Control

Standard AG, Well Work

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix AJ in the Underground Storage Risk and Integrity Management Plan, Rev 5

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix AJ to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Pacific Gas and Electric Company

Well Bring-In

SUMMARY

Purpose:

Once a rework of well is completed a procedure shall be developed to unload the well of the fluid and bring-in the well once a rework of well is completed. The procedure will be prepared and approved as part of the project program and may require an adjacent well to displace the fluid column in the tubing string such that the hydrostatic pressure is sufficiently reduced and allows for reservoir pressure to lift the remaining fluid.

TARGET AUDIENCE

Reservoir Engineering

PG&E Well Site Supervisor

PG&E Gas Construction Team

Drilling Rig Supervisor and Team

Other Contract personnel.

All entities are responsible for pre-job planning, safety meetings, and assigning personnel to perform the execution and monitoring functions of this program.

Updates to this program may be necessary due to changes in Facility, Operational needs or permit requirements.

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Well Bring-In

Procedure Steps

The well specific procedure should follow the steps below and consider modification based on a process hazard review. The procedure must be included in the well work program documents.

Changes to the procedure below may be needed to due to changes in Facility and well configurations.

Well Bring-In Program shall be approved and included with well work program if modified from the steps included in this Procedure

1. **Step Guidance**

   Engineer: Prepare and review the bring-in procedure with the well site manager utilizing the following steps as a guidance in preparing the procedure.

   1.1. Determine utilization of coiled tubing unit

   1.2. Determine reservoir pressure

   1.3. Determine configuration of the well in developing program

   1.4. Use slickline and install XN plug, isolate string from reservoir pressure if well equipped with tubing set on packer.

   1.5. Pressure test tubing and tubing-casing annulus or production casing

   1.6. Use slickline if well is equipped to shift sliding sleeve to open above packer if well is equipped, to circulate the well.

   1.7. Consider if an adjacent well can be used to displace gas down tubing while taking returns from the casing valve if casing valve installed. If well is not equipped with sliding sleeve displacement of the gas will be into the reservoir - Design not to exceed a wells fracture gradient

   1.8. Shut in the well, after tubing string has equalized with adjacent well’s reservoir pressure.

   1.9. Use slickline to shift sliding sleeve closed and pull XN plug if equipped

   1.10. Allow the well flow and bring in well through the tubing

Well Bring-In

2. Engineer and Well Site Manager: Complete a PHA and revise program to address PHA risks.

   2.1. Confirmation that the flare stacks are not located near any permanent or temporary vent stacks

   2.2. Communication with operations staff prior to flaring beginning

3. Engineer: Seek approval from manager of the procedure and include within the program documents

END of Requirements

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in Standard 1.

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1

Standard AN, Well Control

Standard AG, Well Work

Supplemental References:

n/a

Well Bring-In

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix AK in the Underground Storage Risk and Integrity Management Plan, Rev 5.

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix AK to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Blowout Preventer Inspection

SUMMARY

Purpose:

This document provides an overview of the inspection process of the BOP to be conducted in the field to identify any issues that would prevent the BOP from functioning or providing adequate well control during the rework process.

TARGET AUDIENCE

Reservoir Engineering

PG&E Well Site Supervisor

Drilling Rig Supervisor and Team

Other contract personnel.

All entities are responsible for pre-job planning, safety meetings, and assigning personnel to perform the execution and monitoring functions of this program

TABLE OF CONTENTS

Blowout Preventer Inspection

1. General Requirements

The BOP shall be fully inspected and certified by the provider prior to delivery at first well and every 90 days thereafter. In between full inspections, the following actions should be taken before nipping up the BOP to ensure all equipment is functioning safely and properly. If any issues are identified, return BOP to vendor for full inspection (refer to vendor inspection procedure provided elsewhere)

2. Procedure – Annual BOP

2.1. Visually inspect the outer body for any visible damage or corrosion

2.2. Visually inspect the flange connections and bolts for any sign of stretch, damage or corrosion

2.3. Visually inspect the annular element for any apparent rubber loss or damage

2.4. Visually check through bore for any restrictions, washing, kelly whip or any other damage Land tubing string in the wellhead

3. Procedure –BOP Ram Type

3.1. Visually inspect the outer body for any visible damage or corrosion

3.2. Visually inspect the flange connections and bolts for any sign of stretch, damage or corrosion

3.3. Visually check through bore for any restrictions, washing, kelly whip or any other damage.

3.4. Ensure locking shafts are exposed, unless shut in for a reason

3.5. Ensure pipe rams match the work string selected for the project

3.6. Function test rams to ensure they are working properly

4. Accumulator

4.1. Visually inspect the Accumulator, bottles and hoses for any visible damage or corrosion

4.2. Ensure the pressure gauges are reading the correct values

4.3. Ensure adequate amount of fluid in the reservoirs for full closure of all BOP elements

4.4. Ensure accumulator is able to charge reservoirs to necessary pressures

END of Requirements

Blowout Preventer Inspection

DEFINITIONS

Refer to definitions in API 1171 and CalGEMs regulations.

IMPLEMENTATION RESPONSIBILITIES

Gas Storage Asset Management Department

GOVERNING DOCUMENT

GSAM Standard 1

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Regulatory codes listed in GSAM Standard 1

REFERENCE DOCUMENTS

Developmental References:

Prior editions of GSAM IMP and the regulatory codes listed in GSAM Standard 1

Standard AN, Well Control

Standard AG, Well Work

Supplemental References:

n/a

APPENDICES

n/a

ATTACHMENTS

n/a

DOCUMENT RECISION

The replaces Appendix AL in the Underground Storage Risk and Integrity Management Plan, Rev 5.

Blowout Preventer Inspection

DOCUMENT APPROVER

Larry Kennedy, Strategic Planning Chief, GSAM

DOCUMENT OWNER

Lucy Redmond, Director, GSAM.

DOCUMENT CONTACT

Larry Kennedy, Strategic Planning Chief, GSAM

REVISION NOTES

Where?	What Changed?
Converted RIMP Appendix AL to this standalone procedure	Minor language changes were made for clarity. No content changes were made

Well Site Manager

SUMMARY

This procedure is to provide guidance for overseeing rework and abandonment operations on PG&E wells in its gas storage fields. It is not intended to be an exhaustive list of activities to be performed by a well site manager (WSM). Responsibilities may change based on the scope of the rework and abandonment operations overseen. WSMs include PG&E reservoir specialists, engineers, and contractors supervising rig workover operations.

Planning WSM (PWSM) is the same role listed above other than this person will support the planning phases of a project and will be assigned to a well on an "as needed" bases.

This procedure covers all of PG&E's gas storage and production fields in California. Reworks include any work done on a PG&E well while a workover rig is on location. If other equipment, such as a slickline unit, a wireline logging unit, or a coiled tubing unit is also on location, additional standards may apply. A separate standard will apply to drilling operations.

TARGET AUDIENCE

- PG&E Reservoir Specialist
- Well Site Managers and Planning Well Site Managers
- PG&E Reservoir Engineering
- Well Work Project Managers

Informed Audience:

- o Gas Storage Asset Management (GSAM)
- o PG&E GSAM Storage Projects Reservoir Engineering
- o GSAM Integrity Management Engineering
- o Technical work supervisors

SAFETY

WSMs work closely with the rework safety specialists to verify all operations at the well site are conducted in accordance with PG&E and contractors safety protocols. In addition to these protocols, well work operations are required to adhere to the following regulations:

- **Cal OSHA Regulations, Division 1. Department of Industrial Relations, Chapter 4. Division of Industrial Safety, Subchapter 14. Petroleum Safety Orders--Drilling and Production, CCR.**

- **California Code of Regulations (CCR), CHAPTER 4. Development, Regulation, and Conservation of Oil and Gas Resources, Subchapter 1. Onshore Well Regulations (CalGEM)**

The following American Petroleum Institute Recommended Practices (API RP) are additional references for safety information not covered in PG&E and contractors safety guidance, OSHA regulations, and CalGEM regulations:

- **API RP 54 Occupational Safety and Health for Oil & Gas Well Drilling and Servicing Operations**
- **API RP 76 Contractor Safety Management for Oil & Gas Drilling and Production Operations.**

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Requirements:

The WSM works closely with Reservoir Engineering and the project managers. Activities for which the WSM is responsible are outlined here. The WSM may also be consulted or informed on the well work activities by those involved with the activity. The WSM shall verify equipment is fit for purpose, in accordance with approved operating limits, and confirm compliance with industry best practices and standards.

WSM shall document completion of each activity as described in this procedure.

1. Design Phase / Program Review

- The PG&E project manager and/or lead engineer will provide documentation for specific well work plans and a current well diagram and review it with the PWSM prior to any work being performed.
- The lead engineer will order the material and equipment, i.e., wellheads, tubulars, etc. required for the well work, and the project manager will verify it is ordered as appropriate.
- The project manager and/or lead engineer will provide the PWSM with the approved rework program, which the PWSM will then be responsible and accountable for reviewing and understanding.
- The lead engineer and project manager may be consulted as needed to complete these activities.

- WSM shall assist project manager in planning for well work by reviewing location and hazards associated with well location.

2. Site Preparation / Pre-Mobilization

- PWSM is responsible for identifying site hazards (as are other parties) associated with the work planned. These hazards are then to be discussed/mitigated with the project manager who will assess the risk, evaluate, and prioritize risk management options.
- PWSM, is to confirm that the well pad, the rig, the equipment layout and spacing, and the traffic pattern meets safe working conditions. This includes the planning, directing, and coordinating of the safe transportation of equipment and required services. WSM may use **Google Earth or aerial layout** plan as part of the review but for off platform wells a **Google Earth or aerial layout** plan will be prepared.
- PWSM is to coordinate the service of the wellhead lock-down pins with the wellhead contractor for the rework well as appropriate. Project Management is responsible to have a contact with the vender for support of these activities.
- PWSM is to review the rig layout plan with the rig contractor.
- WSM is to refer to Procedure AL, “BOP Inspection Process” for the BOPE inspection process.
- WSM is required to review the Environmental Release to Construction document (ERTC) and verify the requirements contained in it are complied with during well work operations.
- WSM is responsible for posting in project trailer any identified Health, Safety, and Environment (HSE) requirements such as signage, printing and posting large copies of wellbore schematics and other relevant information.
- The storage and use of disposal materials required is the responsibility of the WSM.
- WSM is to prepare rework file folders and rework book, confirming well set up in Unifier for the field and daily report and cost sheets. Refer to the Daily Report Workbook for checklists and daily report creation.
- WSM is responsible for posting the CalGEM permit and any required CalGEM notifications for BOPE inspections and sign offs required.
- WSM will confirm facility fire curtains, well sheds and fire monitors are set up appropriately.
- WSM and Gas Transmission General Construction (GTGC) shall manage the drilling of the rat hole (if needed for a drilling rig) in accordance with GSAM Procedure AI, “Rathole Drilling Program.

- WSM is responsible for confirming the delivery of debris boxes with open tops and liners.

- WSM is responsible for moving in frac tanks with secondary containment berms and verifying that poly tanks with a secondary containment berm are on site as required for the well work

- WSM shall post and maintain in project trailer the list of contractor contacts for each service/rig company.

- WSM is responsible for preparing and/or reviewing the kill sheet (see example in attachments).

- WSM is responsible for assembling the rework documentation and files within the "well folder" for keeping well records (i.e., approved program, kill sheet, aerial layout, contractor lists, etc.).

3. Onsite Operations / Well Work

- WSM will confirm/or verify that all pre-mobilization activities have been completed, such as well kill preparation, well disconnected from facility, and site inspection.

- WSM will assemble execution documentation, including permits.

- WSM is to execute the approved program and adhere to permit requirements.

- WSM is responsible for verifying that all procedures that are used are up to date, both internal and external and are reviewed as needed

- WSM will verify and confirm material and equipment are available or on the well site.

- WSM is responsible for monitoring and checking the material/equipment inventory that are necessary to complete the well program are available.

- WSM will confirm that the kill and choke manifolds, separators and piping, back-pressure valves, and drill pipe test sub(s) have been maintained and are ready for use in accordance with CalGEM M07 and permit requirements. (This includes PG&E and contractor owned equipment).

- WSM is responsible for communicating job expectations and details of well program to all team members at the wellsite, and explaining operational, technical, and logistical issues to each wellsite team member as appropriate.

Primary responsibilities for the WSM during rig operations include:

- Review “before rig work starts” checklist tab of daily report workbook.
- Confirm all kill/choke piping systems, configuration, and management of well control equipment, and conducting and documenting well control activities are compliant with PG&E procedures.
- Perform well kill and document fluid loss and pressure results.
- Confirm site safety and orientation training for all personnel who begin work after the initial commencement of work as outlined in GSAM Procedure AH.
- Oversight of all wellsite personnel and operations during the rework or abandonment.
- Oversight of all rig operations, including confirmation that materials delivered are accurate and complete, confirmation of all fluid make up and parameters.
- Coordination of onsite environmental activities identified in the ERTC such as dust suppression and other requirements, appropriate response to a change in condition (i.e. dust suppression), all identified hazards and verify the site is safe for operations. Project Management is accountable for setting up contracts or working with EFS to set up the construction site such that the site BMPs and dust suppression are in alignment with the ERTC.
- Verify vendors are approved for use and coordinate vendor sequencing.
- Pressure testing of all required lines, routine testing of safety equipment per permit and program requirements.
- Create all pipe tallies using the form identified in the daily report workbook.
- Daily vendor field ticket review and sign off. Review charged hours, SAP Project Systems Integration (SPSI) codes, correct well name and/or order numbers indicated on field ticket.
- Check and file all documents in the “daily tasks” checklist tab as listed in the daily report workbook.

Communication requirements for the WSM include:

- Notification as necessary to CalGEM and contractor notifications.
- Document all well interventions and pertinent data.
- Confirm and transmit all logging records to Integrity Management Engineering.
- Conduct tailboard meetings for new equipment, new procedures, work pause, new steps in program, if needed PHA review.

- Report all safety and environmental events, near misses, spills, and changes to identified hazards to PG&E supervisor. This can be the project manager, lead engineer, or on-call engineer.

- Well updates and daily reporting, including any abnormal operating conditions (AOCs) with stakeholders.

- If an AOC occurs during the onsite operation, the WSM is to notify the lead engineer/project manager to determine an appropriate response. AOC is a condition identified by the WSM (or any wellsite team member that communicates such condition) that may indicate a malfunction of a component or deviation from normal operations that may:
  - Indicate a condition exceeding design limits; or
  - Result in a hazard(s) to persons, property, or the environment; or
  - Indicate a potential downhole problem not related to design or hazard(s) but that may risk the integrity of the well and/or reservoir; or
  - Require approval from CalGEM to deviate from the approved program.
- Verify all PG&E's record keeping requirements have been met.

- After each shift, the WSM is to complete the "WSM shift turnover" checklist included in the daily report workbook.

4. Preparing for De-Mobilization

- As the rework or abandonment nears completion, the WSM is to start preparing for the next rig move, including:
  - Assemble rework execution documentation.
  - Verify all necessary documents are complete, accurate and filed appropriately.
  - Notification to CalGEM of any inspections required.

- Once de-mob process begins, the WSM responsibilities include as needed:
  - Clean up the well site, help coordinate the remove and dispose of fluids on the ground if necessary, with the help of the GTGC.
  - Schedule the removal and disposal of drilling fluids, including mud and solid disposals.
  - Schedule frac tank cleaning and removal as necessary.

- Schedule drill pipe cleaning/inspection; if necessary, arrange for offsite inspection.
- ~~Verify~~ verify/confirm all contractor equipment and materials have been removed from the site.

- The WSM is to review the checklist for “after rig work”, “move off” and complete the “de-mob checklist” both in the daily report workbook.

5. Record Keeping

The WSM is responsible for preparing and transmitting the Daily Report during well work operations. daily report details include all well work activities, fluid storage and properties, non-productive time (NPT), invoices and personnel on location.

- **GSAM Standard E - Design and Specifications for Construction of Natural Gas Storage Wells, Section E.11** outlines the requirements for well work records that are to be maintained for the life of the storage facility. Specific records are detailed for compliance with **API RP 1171, Section 6.11.1** including those for well casing, cementing, completion, stimulation, well remediation, well abandonment, well testing and commissioning.
- Project manager will confirm the final storage location of the well records compiled from the well work.

END of Procedure

IMPLEMENTATION RESPONSIBILITIES

Reservoir Engineering leadership will communicate the publication of this standard to the affected personnel and provide training to affected personnel.

GOVERNING DOCUMENT

GSAM Standard 1 and related standards and procedures.

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

All well work is to be performed in accordance with the following:

State

1. Permit to Rework issued by CalGEM for the specific well work.
2. California Code of Regulations, Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Development, Regulation, and Conservation of Oil and Gas Resources, Subchapter 1, Onshore Well Regulations
3. DOGGR Publication M07 specifying Blow Out Prevention Equipment

4. Cal OSHA regulations for Construction as applicable

Federal

1. Code of Federal Regulations (CFR) Chapter 49, Part 192, Subpart 192.12, Underground Natural Gas Storage Facilities
2. PHMSA's 2018 law implementing API RP 1171 as federal law
3. OSHA regulations for construction as applicable

RECORDS AND INFORMATION MANAGEMENT

PG&E records are company assets that must be managed with integrity to ensure authenticity and reliability. Each line of business (LOB) must manage records and information in accordance with the Enterprise Records and Information (ERIM) Policy, Standards and Enterprise Records Retention Schedule (ERRS). Each Line of Business (LOB) is also responsible for ensuring records are complete, accurate, verifiable and can be retrieved upon request. Refer to GOV-7101S, "Enterprise Records and Information Management Standard," for further records management guidance or contact ERIM at Enterprise_RIM@pge.com.

Appendices

N/A

Attachments

- Example Kill Sheet
- Daily Report Workbook

Document Recision

This is the initial version of this standard (Rev 0 once approved and issued).

DOCUMENT APPROVER

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DOCUMENT OWNER

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DOCUMENT CONTACT

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Revision Notes

Where?	What Changed?
N/A	This is a new standard

Well Control

SUMMARY

The Well Control Standard provides minimum requirements to ensure well control is maintained at all times during well work operations on PG&E gas storage and gas production wells. It is applicable to the types of well interventions commonly performed in PG&E fields, including well kills, rig reworks, abandonments, coiled tubing operations, and wireline logging, as well as drilling and completion operations. Well intervention using a snubbing unit is not addressed in this standard. This standard does not apply to storage well injection and withdrawal operations. Other PG&E procedures/standard operating procedures (SOPs) and guidance documents provide detailed instructions and guidelines for implementing this standard.

TARGET AUDIENCE

This standard applies to all engineering, technical, operations, and contractor personnel engaged in well engineering, design, and well work execution.

SAFETY

Proper well control procedures and equipment are fundamental to personnel and process safety during well work operations and are intended to minimize the risk of injury, death, fire, property loss, and environmental damage from the uncontrolled release of formation fluids.

Implementing this standard can involve safety hazards that require proper procedures, including

- Pressure testing blowout prevention equipment (BOPE) and lines
- Lifting, handling and securing heavy BOPE and lines
- Trapped fluid pressure below closed BOPE and behind closed valves
- Fall and dropped object risk while working on the BOP stack

Well Control

TABLE OF CONTENTS

1. Introduction

Well control refers to the procedures and equipment used to prevent and safely handle the unintended flow of formation fluids from subsurface reservoirs. Formation fluid that flows into a well bore during well work activities is referred to as an influx or kick. If not controlled properly, a kick can develop into a blowout which is the uncontrolled release of formation fluids from the well. A surface blowout refers to formation fluid exiting the well from the casing, tubing or tree above ground level. A subsurface blowout refers to formation fluid exiting the well below ground level; depending on well pressure and subsurface conditions, a subsurface blowout can broach to the surface and become a surface blowout near or away from the well.

This standard covers all PG&E-operated wells in the McDonald Island, Los Medanos and Pleasant Creek fields. Formation fluids in these fields include stored natural gas present in storage zones as well as natural gas present in non-storage zones, both of which are considered hydrocarbon-bearing formations for purposes of this standard.

Formation pressure in the storage zones varies throughout the year depending on storage gas withdrawals and injection, which are driven by PG&E natural gas system supply and demand. Maximum allowable storage zone pressure is limited by CalGEM permit as referenced in Table 1.

Maximum anticipated surface pressure (MASP) is the highest pressure predicted to be encountered at the surface during well work activities. MASP can result from formation pressure or from pressure applied to the well during well work operations (e.g., during pressure testing). Calculation of MASP resulting from formation pressure shall consider that the wellbore is filled with storage gas (gas-to-surface) and is referenced in Table 1.

Table 1 – Maximum Allowable Storage Zone and Maximum Anticipated Surface Pressures (MASP)

Field	Storage Zone	Depth	Max. allowable storage zone (reservoir/formation) pressure	Maximum Anticipated Surface Pressure (MASP)	
				MASP[1] (gas-to-surface) at maximum field pressure (max. storage volume/ pressure)	MASP (pressure test) CalGEM-required casing pressure test to 115% of maximum allowable injection pressure
McDonald Island	Mokelumne River	5200 ft	2,365 psi	2,070 psi	2,400 psi
Los Medanos	Domengine	4100 ft	1,774 psi	1,600 psi	1,840 psi
Pleasant Creek	Peters / Winters	2800 ft	1,353 psi	1,240 psi	1,440 psi

The term “shall” is used to identify a minimum requirement to comply with this standard. The term “should” is used to identify a recommendation that is generally advised but may be impractical or unnecessary under certain circumstances.

2. Applicable Guidance

2.1 State and Federal Law

PG&E well work operations shall comply with the conditions contained in permits issued by CalGEM (formerly DOGGR), Publication M07 (Procedure MO7), *Blowout Prevention in California*, and all state and federal laws. State and federal statutes and regulations related to well control are listed in the Compliance Requirement / Regulatory Commitment section below.

2.2 Industry Guidance

Industry standards are listed in the Reference Documents section below. Industry standards that have been adopted in part or in whole in this standard are listed as Developmental References. Other industry standards are listed as Supplemental References.

[1] CalGEM (formerly DOGGR) uses the term Maximum Predicted Casing Pressure (MPCP), maximum bottom hole pressure less the hydrostatic pressure of a gas column. MPCP equals MASP (gas-to-surface) at maximum field pressure/storage volume.

2.3 Internal Guidance

PG&E guidance documents are indispensable to the application of the Well Control Standard. The following guidance documents are incorporated into this standard by reference:

- GSAM Procedure AJ, *Well Kill Program*
- GSAM Procedure AL, *BOP Inspection Process*
- GSAM Procedure AD, *Rig Evacuation Procedure*

Other Relevant PG&E Documents Describe Emergency Response / Emergency Preparedness, Recordkeeping Requirements, Tubular Design Standard, And Wellhead Equipment Design Standard.

3. AOC/MOC

A kick or well control incident meets the definition of an Abnormal Operating Condition (AOC) as a deviation from normal operations that may result in a hazard(s) to persons, property, or the environment. AOC notification and documentation procedures are described in GSAM Procedure 19 and GSAM Standard AG, Well Work. Contractors shall immediately notify the well site manager (WSM) who shall document the incident in the daily well work report.

Changes to an approved well work program require compliance with GSAM Procedure AC Management of Change *for Well Rework,* which describes the three levels of Management of Change (MOC) and communication and approval requirements.

If the requirements of this Well Control Standard cannot be completed, a variance must be obtained per Utility Procedure TD-4001P-07, *Gas Operations Variance Process*.

4. Barrier Requirements

4.1 Rig Well Work

A minimum of two independent barriers between hydrocarbon-bearing formations and the surface shall be maintained during well work operations performed with a rig.

Examples of barriers during well work include

- Kill weight fluid in a static well bore
- Retrievable or permanent bridge plug
- Packer with packer plug
- Cement plug
- Casing float equipment
- Tubing hanger with back pressure or two-way check valve installed
- Downhole tubing plug
- Pressure-tested casing and tubing
- BOPE operated, maintained, and tested in accordance with this standard

The primary barrier during rig well work operations is kill weight drilling or workover/completion fluid where the hydrostatic pressure exerted by the fluid exceeds the formation pressure. This difference in pressure is referred to as overbalance. A fluid overbalance of 300 psi shall be maintained during well work operations unless otherwise specified in the approved well work program.

The rig BOP stack is considered a single barrier because it relies on a common actuating/control system (accumulator); its reliability as a mechanical barrier depends on operational processes: detecting a kick, responding appropriately, and the proper design, maintenance and operation of the actuating system to close the BOP.

Barriers should be tested or verified whenever feasible; barrier verification procedures shall be specified in the well work program. Consideration should be given to pressure testing in the direction of flow.

Two barriers shall be in place prior to removing the production tree before rig operations or removing the BOP stack following rig operations. A closed downhole safety valve (DHSV) is not considered a barrier for this purpose.

During certain rig well work operations, it is not feasible to install two barriers. A risk assessment and/or process hazard assessment (PHA) shall be performed before conducting well work operations with less than two barriers.

4.2 Wireline Operations

Wireline operations performed with a rig on the well and a BOP stack installed shall be performed with two barriers in place. Typical barriers would consist of the following:

1. Kill weight fluid as the primary barrier;
2. Pressure-tested casing and bridge plug (or packer plug);
3. Rig BOP stack and/or a wireline lubricator assembly.

For through-tubing wireline operations performed on a live (pressurized) well through the production tree, the primary barrier is the wireline lubricator assembly, consisting of wireline rams (valve), lubricator sections, and a pressure control head (stuffing box for slickline or grease injection head for braided or electric line). A secondary well barrier would consist of a wireline safety head, i.e., a shear/seal closure device capable of cutting the wireline and sealing the wellbore; a master valve can serve as the safety head if it has the documented ability to cut wireline and seal. A secondary barrier is generally not installed at PG&E for through-tubing wireline operations on live wells.

4.3 Coiled Tubing Operations

For well interventions performed under pressure on live wells using coiled tubing, two mechanical barriers shall be employed. Acceptable mechanical barriers for coiled tubing operations consist of the following:

1. The combination of a stripper/annular sealing component, or pipe ram sealing component, and a flow check assembly (with minimum of two back pressure valves) installed within the coiled tubing bottom hole assembly (BHA);

2. A single blind ram and a single shear ram;
3. A shear-blind combination ram.

5. Well Work Program Design

A well-specific program shall be prepared for each well work project. The program shall include the following information:

- Description of proposed well work and step-by-step procedure
- Wellbore schematic showing current and proposed construction of the well, including completion equipment
- Current well condition including wellbore fluids, wellbore restrictions, directional survey, well pressure, pressure on annuli (if any), and description of existing wellhead/tree.
- Description of the barriers to be employed during the well work, including barrier type, installation location/depth, and verification method, if any.
- Well control equipment installation and testing requirements, including BOP type/model, size, pressure rating, and ram types/sizes.
- Anticipated storage zone pressure and temperature. Anticipated formation pressure in other permeable zones that may be exposed during the well work.
- MASP during the well work, which is the greater of MASP resulting from the formation (gas-to-surface) or MASP resulting from well work operations (maximum pressure surface equipment will be subjected to while executing the well work program).
- Fluid density to maintain 300 psi overbalance during rig well work.
- Estimated fracture gradient for exposed formations. Plans, if any, for performing leak-off tests or formation integrity tests during rig well work.
- Estimated kick tolerance for rig well work: Volume of gas influx (kick) that can be circulated out of the well without fracturing exposed formation based on field conditions.
- Identify unique well control risks and mitigations, if any, and provide contingency plans, as required.

Wellhead and BOP/well control stack drawings, and a site layout drawing showing rig components, mud pits, accumulator, choke manifold, flare/vent line, fluid tanks, auxiliary pump connection point on kill line, and emergency road access should also be prepared and included in the well work program.

Rig well work design, including casing design/analysis, should provide for a minimum 20-bbl gas kick tolerance. A risk assessment and/or PHA that considers the risks of an underground blowout and broaching to the surface shall be performed if kick tolerance is less than 20 bbls.

Preparation of a well-specific well control (blowout prevention and control) plan should be considered for drilling or redrilling operations.

The well work program shall be provided to the rig contractor, fluids contractor, wireline contractors, coiled tubing contractor, and other contractors having a role in well control. The program shall be reviewed with contractors prior to performing the well work.

6. Well Kill

Killing a well involves replacing hydrocarbons in a well with kill weight fluid to prevent the well from being able to flow. PG&E wells shall be killed before removing the tree and installing BOPE for rig well work. Circulating kill weight fluid is the normal method of killing a PG&E well. Well kills shall follow the latest version of the PG&E *Well Kill Program* (GSAM Procedure AJ) or as specified in the approved well work program.

Bullheading kill weight fluid into the formation is another method for killing a well and is used for responding to certain well control incidents but should not be used to kill a well for routine well work.

7. Rig Well Work

7.1 Well Control Equipment Requirements

Blowout prevention equipment (BOPE) installation, inspection and testing shall meet or exceed the requirements of Procedure M07.

BOPE shall be manufactured in conformance with the following American Petroleum Institute (API) standards in effect at the time of manufacture:

- Annular, ram preventers, mud cross: API Spec 16A, *Specification for Drill-Through Equipment*
- Choke and Kill Equipment (including PG&E Kill Manifolds, and PG&E and rental Choke Manifolds): API Spec 16C, *Choke and Kill Equipment*
- Gate valves and end connections: API Spec 6A, *Specification for Wellhead and Tree Equipment*
- Control Systems (Accumulators): API Spec 16D, *Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*

The latest edition shall be used for modifications, remanufactured, or replacement equipment. Repair and remanufacture of annulars, ram preventers, and mud crosses should be in compliance with API Spec 16AR, *Standard for Repair and Remanufacture of Drill-through Equipment.*

API 6A material class DD, PSL 2, and temperature rating U (0°F to 250°F) are acceptable for PG&E service. Following the adoption of this standard, newly manufactured BOPE should be API monogrammed at the time of manufacture.

BOPE used during rig well work (reworks, abandonments, drilling, redrilling) shall have a minimum working pressure rating of 3000 psi and be sized to allow passage of all tools, equipment, and tubulars that will be run or removed during the well work program.

BOPE shall be installed for all well work performed by a rig and shall consist of 1) a Class III (3) BOP stack and associated control system, 2) choke and kill lines, 3) a choke manifold with two adjustable chokes and a unchoked bleed line, and 4) adequately sized control system, and 5) auxiliary equipment. BOPE shall be installed, operated, and maintained in accordance with API Std 53, *Well Control Equipment Systems for Drilling Wells*, with the following exceptions:

- A remotely operated valve on the choke line (HCR valve) is not required for reworks and abandonments (but is required for drilling/redrilling).
- A trip tank is not required for reworks and abandonments (but is required for drilling/redrilling).
- The choke line and primary kill line shall be attached to the side outlets of a mud cross (drilling spool), rather than to side outlets on the BOPs.
- Connection of an auxiliary kill line to a wellhead side outlet is acceptable during reworks and abandonments (but not during drilling or redrilling).
- The following minimum sizes shall apply to the mud cross and choke and kill equipment:
  - Mud cross side outlets: One 2” and one 3” (to comply with Procedure M07)
  - Kill line: 2”
  - Choke line (main and bleed lines): 3” (to comply with Procedure M07)
  - Chokes and choke wing lines: 2”

Choke and kill lines shall each have two full-opening (full-bore) control valves installed at the mud cross. A check valve shall be installed on the kill line. The kill line shall not be used as a fill up line. An auxiliary pump connection tie-in shall be provided on the kill line.

A full-opening safety valve (FOSV, aka TIW valve) shall be readily available on the rig floor (stored in the open position with wrench accessible) along with crossovers to all pipe planned during well work operations. A circulating swage shall be on the rig floor during casing running.

An inside blowout preventer (IBOP) with crossovers (if required) to the FOSV shall be readily available on the rig floor. The IBOP shall be stored or identified such that it is not the first valve installed in response to a kick while tripping.

Hole Fluid Monitoring Equipment meeting CalGEM (DOGGR) Class C requirements shall be installed for all rig well work. Class C monitoring equipment consists of the following:

- Pit volume totalizer
- Pump stroke counter
- Flowline sensor
- Gas detection equipment

Additional Requirements for Drilling and Redrilling

A diverter with 6” minimum outlet should be installed when drilling below conductor or below surface casing if there is inadequate kick tolerance and a risk of an underground blowout and broaching to the surface.

A diverter allows for directing uncontrolled flow from a shallow gas zone away from rig personnel and equipment. Diverter equipment shall be installed, operated, and maintained in accordance with API Std 64 and Procedure M07.

BOPE, as described above for rig well work, shall be installed on the first casing string below the conductor.

A float valve should be installed in the drill string during drilling and redrilling operations not requiring reverse circulation.

A mud/gas separator (MGS) should be installed on one of the choke outlet lines of the choke manifold during drilling and redrilling operations.

7.2 Inspection and Testing

Rig BOPE inspection and testing shall follow API Std 53 with the following exceptions:

- Both the initial and subsequent pressure tests on a well shall be performed to a low-pressure test of 300 psi followed by a high-pressure test, as follows:
    - Annular preventer: ≥MASP or 70% of rated working pressure, whichever is lower.
    - Ram preventers: ≥MASP
    - Choke and kill system:≥MASP
    - Auxiliary equipment: 3000 psi.

The following test pressures apply for typical rework operations where MASP results from the CalGEM-required casing pressure test (115% of maximum allowable injection pressure):

Field	Low Pressure Test	High Pressure Test	
		Annular (3000 psi RWP)	Rams, Choke & Kill
McDonald Island	300 psi	2100 psi	2500 psi
Los Medanos	300 psi	1900 psi	1900 psi
Pleasant Creek	300 psi	1500 psi	1500 psi

BOPE pressure testing should be performed with a test plug installed in the wellhead. Following the initial pressure test after BOPE installation, BOPE pressure testing shall be performed at least every 21 days.

If a BOPE connection is broken during operations, the broken connection shall be re-tested after re-assembly. After a ram change, pipe rams shall be re-tested per the table above, except for casing rams which should be function tested; ram bonnet seals shall also be re-tested after any ram change. Variable rams should be tested with the sizes of pipe that will be used during the well work.

An accumulator drawdown test shall be performed prior to beginning downhole operations on the first well of a rig well work campaign, after accumulator repairs, and every six months from the previous test. API Std 53 (Section 5.3.14) and Procedure M07 (Section 5-2) provide procedures for accumulator drawdown testing. The final accumulator pressure shall be at least 200 psi above the precharge pressure.

BOPE Inspection shall also comply with GSAM Procedure AL, BOP Inspection Process.

All BOPE should be function tested at least weekly, alternating between control stations, or as specified in the well work program. Closing times shall meet API Std 53 and Procedure M07 requirements.

The pressure integrity of the casing on the which the BOP stack is installed is needed for well control. The casing should be pressure tested to MASP as soon as practical during the well work procedure. If a pressure test to MASP is not feasible due to concerns about casing integrity, the casing should be pressure tested to the surface pressure that would be experienced in circulating out a 20 bbl gas kick; a pressure test to 1000 psi meets this requirement in PG&E-operated fields.

7.3 Kick Prevention, Detection, and Response

Hole monitoring equipment should be checked, and alarms actuated at least once each tour.

Before to tripping, fluid shall be conditioned, and density measured to confirmed adequate overbalance (300 psi or as specified in the approved well work program). In addition, the annulus shall be checked to confirm no fluid flow or loss. These observations shall be noted on the rig contractor’s IADC/daily report. A hole filling program shall be followed and monitoring of fluid filling shall be performed on all trips.

Time with pipe out of the hole should be minimized. During long rig repairs or shutdowns, a kill string should be run.

Record BOPE accumulator pressure and slow pump rate and pressure each tour.

Rig crews shall be observant for warning signs of a kick at all times, which can include the following:

- Pit volume gain
- Increased flow from annulus
- Gas-cut fluid
- Change in pump speed or pressure
- Volume of fluid to keep hole full on trips is less than expected
- Increase in penetration rate
- Lost circulation

If a kick is suspected, a flow check should be performed. If the flow check indicates the well is flowing, the well shall be shut in with the BOPE as quickly as possible (unless a diverter is installed).

Well Control

Figure 1, *Flow Check and Shut-In Procedures*, describes procedures for shutting-in while drilling (or when on/near bottom of the wellbore) and while tripping. The hard shut-in method, which keeps chokes closed during normal operations, should be employed.

If there is any doubt whether a kick is taking place, the well should be shut in until the situation can be assessed. The WSM and rig manager (toolpusher) shall be notified immediately after shutting in the well.

Well Control

SHUT-IN PROCEDURES

Shut-In Procedures While Drilling

or While On/Near Bottom During Reworks

1. Stop rotating, pick up off bottom and sound alarm
2. Position kelly/top drive so that no tool joint is across the ram
   - If possible, have uppermost tool joint at connection height above rotary table/rig floor
3. Stop pump(s), check for flow; if flowing, proceed to step 4
4. Shut in the well
   - Open the valve/line (HCR) from the BOP stack outlet to the choke manifold
   - Close the designated BOP (annular or ram)
     > For a hard shut in, the choke should already be closed
     > ~~For a soft shut in, remember to close the choke~~
   - Verify the well is shut in and flow has stopped
5. Notify supervisory personnel
6. Begin recording
   - Shut-in drillpipe pressure (SIDPP) and shut-in casing pressure (SICP)
   - Initial time of shut-in, kick depth and gain in pits

If no HCR, close BOP first, then open choke line valve

Note: Record SIDPP and SICP at regular intervals (i.e., every minute).
Remember, you must determine stable pressures for Operations to complete the killsheet.

Shut-In Procedures While Tripping

1. Stop tripping and sound alarm
2. Space out so that no tool joint is across the ram
   - Ensure that the uppermost tool joint is at connection height above rotary table/rig floor
3. Stab the full-opening safety valve on the drill string
   - Make up safety valve and close
4. Shut in the well
   - Open the valve/line (HCR) from the BOP stack outlet to the choke manifold
   - Close the designated BOP (annular or ram)
     > For a hard shut in, the choke should already be closed
     > ~~For a soft shut in, remember to close the choke~~
   - Verify the well is shut in and flow has stopped
5. Install kelly/top drive and open safety valve
6. Notify supervisory personnel
7. Begin recording
   - SIDPP and SICP
   - Initial time of shut in, kick depth and gain in pits

If no HCR, close BOP first, then open choke line valve

Note: Record SIDPP and SICP at regular intervals (i.e., every minute).
Remember, you must determine stable pressures so that Operations can complete the killsheet.

WILD WELL CONTROL

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Figure 1 - Flow Check and Shut-In Procedures

If a diverter is installed and a kick is suspected, the procedures described in the drilling program should be followed.

Gas kicks should generally be removed from the wellbore by forward circulation using the Driller's Method, which is PG&E's preferred method of kick circulation. Other forward circulation methods include the Wait and Weight Method and the Circulate and Weight (Concurrent) Method, which may be preferable in certain well control situations. All three methods are described in Section 9.2 of API RP 59.

Other well control methods, which are described in API RP 59 and well control school training materials, include the following:

- Reverse circulation
- Bullheading
- Lube and bleed
- Volumetric (gas bubble migration)

Procedures for dealing with special well control problems and complications are described in Section 12 of API RP 59.

8. Wireline

8.1 Well Control Equipment Requirements

Pressure control equipment shall be installed for all wireline (electric line, braided line, or slickline) operations performed through-tubing, consisting of the following (from top to bottom):

1. Pressure control head:
    a. Stuffing box for slickline, or
    b. Grease injection for braided or electric line on live wells, a pack off is acceptable for braided or electric line during rig work with kill weight fluid barrier in place.
2. Lubricator sections with bleeder valve.
3. Single wireline blowout preventer (wireline valves): Blank rams for slickline, or rams grooved for the diameter of braided or electric line being run.
4. Pump-in sub (double valved when working on a live well).
5. Full-opening safety valve (for wireline operations through-tubing during rig work)
6. Connection/crossovers to the tree or tubing

The working pressure rating of all wireline pressure control equipment shall be 3000 psi or greater.

Double wireline valves with grease injection between rams should be considered for severe service (e.g. fishing) or close tolerance operations.

The outside diameter and length of tool assemblies shall be physically verified and documented prior to running. Prior to running or retrieving close tolerance tool assemblies, the internal diameter of the lubricator assembly and wellbore should be physically verified. Prior to retrieving close tolerance assemblies, available documentation should be reviewed to identify tool characteristics (e.g. diameter, length, shoulders). Modelling and/or risk assessment/process hazard assessment should be considered to evaluate the risk of tool sticking, due to close tolerance, deformation or swelling, causing a well control situation.

When required by CalGEM permit, a lubricator shall be installed for through-casing logging during rig well work with a BOP stack installed. For through-casing logging with a lubricator assembly, the lubricator assembly should be secured with a shooting flange bolted to the annular preventer or rotating head.

The length of the lubricator assembly shall be sufficient to allow removal of the wireline tools above a closed tree master valve (through-tubing wireline with tree installed), safety valve (through-tubing wireline during rig work), or blind rams (through-casing wireline during rig work).

The lubricator assembly should be adequately supported and/or guyed during wireline operations.

8.2 Inspection and Testing

Lubricator assemblies, rubber ram blocks, swages and unions shall be visually inspected for defects prior to use. Proper ram type shall be verified prior to use – blank rams for slick line, proper groove diameter for braided or electric line rams.

Wireline pressure control equipment shall be pressured tested to 300 psi (low) and 3000 psi (high) prior to use:

<u>Shop Testing prior to installation</u>

Wireline contractors shall shop test all pressure control equipment provided to PG&E to 300 psi (low) and 3000 psi (high) every six months. Wireline preventer (valve) rams shall be tested for the types of wireline normally provided to PG&E; rams for braided or electric line shall be tested using a steel rod of the same diameter as the wireline provided to PG&E. A log and chart of the pressure tests shall be provided to PG&E and also kept in the wireline truck.

<u>Live wells</u>

Onsite pressure testing is generally not performed on PG&E wells. The use of water as a test fluid poses a risk of forming hydrates.

If onsite pressure testing to 300 psi and 3000 psi is not performed, the wireline contractor shall pressure test all pressure control equipment to 300 psi and 3000 psi in the shop immediately prior to the job and provide PG&E a log and chart of the pressure tests on location or in the wireline truck. In addition, after installation, the entire lubricator assembly and connections shall be pressure tested to field pressure for 5 minutes using field gas prior to running in the hole.

<u>During Rig Work with kill weight fluid barrier in place</u>

No additional pressure testing is required.

9. Coiled Tubing

9.1 Well Control Equipment Requirements

BOPE shall be installed, operated, and maintained during coiled tubing (CT) operations in accordance with API RP 16ST, *Coiled Tubing Well Control Equipment Systems*. Pressure Category 2 (MASP range of 1501 psi to 3500 psi) and a minimum working pressure rating of 5000 psi shall apply.

For operations where returns are taken through the tree or wellhead, a well control stack consisting of stripper assembly and quad ram BOP (blind, shear, slip, pipe) shall be installed in combination with a flow check assembly in the CT BHA (see Figure 5 of API 16ST).

If returns are not taken through the tree or wellhead, a flow tee or cross shall be added to the well control stack below the quad ram BOP (see Figure 6 of API 16ST). An additional pipe ram or annular well control component should be installed below the flow tee or cross if abrasive, corrosive, or high velocity fluid returns are expected. Two full-opening valves shall be installed at the flow tee or cross when working on a live well.

If a flow check assembly cannot be used due to the job design, an additional shear-blind ram shall be installed in the lower most position of the well control stack.

Choke and kill lines and choke manifolds shall comply with API 16ST (Sections 8 and 9), with the exception that PG&E-approved manifolds that comply with Section 7 of this Well Control standard may be used for coiled tubing operations when MASP is ≤3,000 psi.

9.2 Inspection and Testing

Coiled tubing well control equipment shall be inspected and tested in accordance with API 16ST (Sections 12 and 13). Coiled tubing well control equipment shall be tested to a low pressure of 300 psi and a high pressure of at least 1.1 times MASP.

9.3 Abnormal Conditions

Annex B of API 16ST provides contingency procedures and drills for abnormal conditions during coiled tubing operations.

10. Competency, Training and Drills

GSAM Procedure AH, Well Work Contractor Competency, contains PG&E's policies and procedures to ensure the competency of contractors performing well work.

10.1 Well Control Training

The following personnel shall have a current Well Control certificate at the supervisory level from an IADC WellSharp well control school:

- WSMs (PG&E and contractor)
- Rig manager (tool pusher)

- Rig driller (operator/crew chief)
- Lead and on-call engineers (PG&E and contractor)

All other rig personnel shall have introductory training in well control. Rig contractors shall train their employees in the proper installation, operation, testing, and maintenance of BOPE used on the rig.

At least two people on location at any time during rig well work operations shall possess valid well control certification.

10.2 Rig Crew Drills

The following drills shall be performed with the rig crews:

- Pit/BOP Drill
  - On-Bottom
  - Tripping
  - Drill collars across the BOP stack
  - Out of the hole
- Choke Drill
- Rig Evacuation Drill

Section 11.3 of API RP 59 describes Pit, BOP, and Choke drills and recommended frequency and proficiency levels. The Rig Evacuation drill should follow the steps in GSAM Procedure AD, Rig Evacuation Procedure.

Drills shall be held with each crew at least weekly. A record of all crew drills shall be made on the daily well work report.

10.3 Wireline Crew Training

Wireline contractors shall train their employees in the proper installation, operation, testing, and maintenance of wireline pressure control equipment provided to PG&E.

API RP T-6, *Training and Qualification of Personnel in Well Control Equipment and Techniques for Wireline Operations on Offshore Locations*, provides guidance on training wireline operators/supervisors and helpers/assistants on well control where the lubricator assembly is the primary well control barrier.

10.4 Coiled Tubing Crew Training

Coiled tubing contractors shall train their employees in the proper installation, operation, testing, and maintenance of coiled tubing well control equipment provided to PG&E.

11. Well Control Incident Response

The *PG&E Well Control Tactical Considerations* serves as the Blowout Contingency Plan required by API RP 1171. The requirements of the WCTC shall be followed during any well control incident.

Well Control

A kick during rig well work triggers a Level 1 or Level 2 response level. The loss or impending loss of all barriers or an uncontrolled flow (blowout) triggers a Level 3 to 5 response.

A kick where the influx can be safely circulated out of the hole using procedures described in this standard would generally be considered a Level 1 response and be performed by onsite PG&E and contractor resources. A kick or well control incident with complicating circumstances or a kick response that requires bullheading, stripping, snubbing, lubrication/bleeding, or volumetric techniques where an existing PG&E procedure or SOP does not exist would trigger a Level 2 response. Level 2 response may require out-of-area resources and would generally involve consultation with PG&E's well control contractor, Wild Well Control. Level 3, 4 and 5 responses require the involvement of Wild Well Control.

Well control incidents are summarized below and in Figure 2:

- Level 1: ROUTINE - SOP exists for recovery
- Level 2: ELEVATED - Complicating circumstances or no SOP exists for recovery
- Level 3 to 5: SERIOUS, SEVERE, CATASTROPHIC - Loss/Impending loss of all barriers, Blowout

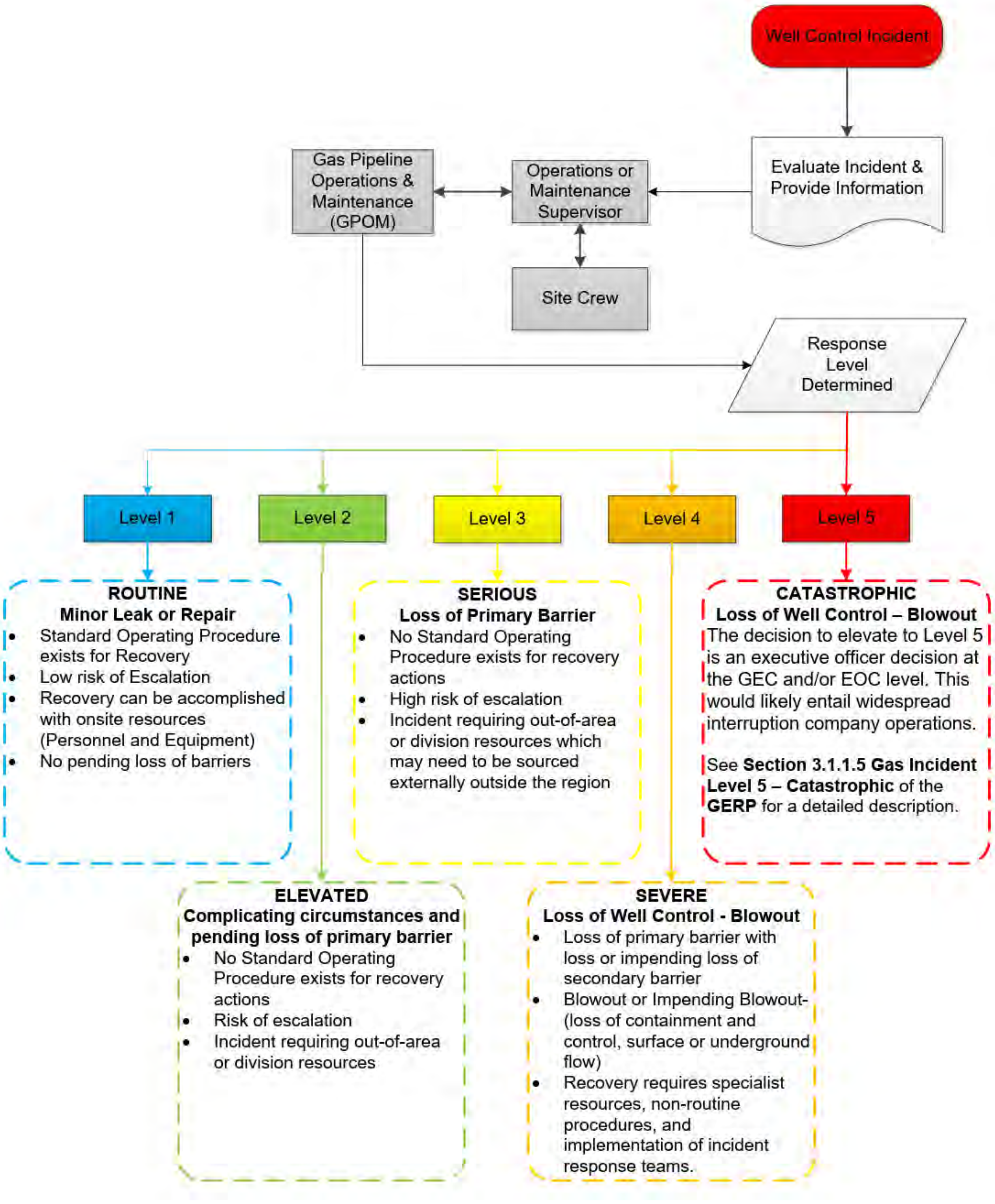

Figure 2 – Incident Response Levels

12. Alignment with Contractor Well Control Practices

This Well Control Standard shall be provided to rig contractors, wireline contractors, coiled tubing contractors, and BOPE suppliers at the beginning of each rework season for the purpose of identifying, addressing and resolving differences or gaps in well control practices and procedures between PG&E and their contractors.

A copy of rig contractors' well control and BOPE standards/procedures should be requested and reviewed by PG&E prior to rig mobilization. Any differences between PG&E's and their rig contractors' standards/procedures should be identified and resolved by preparing an MOC and/or well control bridging document.

As described in Section 5, well work programs shall be provided to contractors to communicate well-specific well control considerations.

END of Requirements

DEFINITIONS

Well control-related definitions are provided in API RP 59 (Section 3.1), API Std 53 (Section 3.1), API Spec 16C, and Procedure M07 (Glossary).

IMPLEMENTATION RESPONSIBILITIES

Reservoir Engineering leadership will communicate the publication of this standard to the affected personnel and provide training to affected personnel.

GOVERNING DOCUMENT

- GSAM Procedure 20. Emergency Response / Emergency Preparedness

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

This standard has been written to ensure compliance with the following statutes and regulations:

- California Public Resources Code (PRC)
- CalGEM Regulations, California Code of Regulations (CCR), Title 14, Division 2, Chapter 4. Development, Regulation, and Conservation of Oil and Gas Resources, Subchapter 1. Onshore Well Regulations.
- Cal OSHA Regulations, Division 1. Department of Industrial Relations, Chapter 4. Division of Industrial Safety, Subchapter 14. Petroleum Safety Orders--Drilling and Production, CCR
- California Air Resources Board (CARB) Regulations

- Federal PHMSA Regulations, Standards – Title 49 Code of Federal Regulations (CFR), Part 192, Subpart 192.12, Underground Natural Gas Storage Facilities

RECORDS AND INFORMATION MANAGEMENT

PG&E records are company assets that must be managed with integrity to ensure authenticity and reliability. Each Line of Business (LOB) must manage Records and Information in accordance with the Enterprise Records and Information (ERIM) Policy, Standards and Enterprise Records Retention Schedule (ERRS). Each Line of Business (LOB) is also responsible for ensuring records are complete, accurate, verifiable and can be retrieved upon request. Refer to GOV-7101S, "Enterprise Records and Information Management Standard," for further records management guidance or contact ERIM at Enterprise_RIM@pge.com.

REFERENCE DOCUMENTS

Developmental References:

The following references have been adopted in whole or in part by PG&E and constitute provisions of this standard:

- GSAM Standard 1, Storage Integrity Management
- GSAM Standard 20, Emergency Response / Emergency Preparedness
- CalGEM (formerly DOGGR), Publication No. M07, *Blowout Prevention in California – Equipment Selection and Testing,* 10th Edition, 2006
- API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, 1st Edition, 2015
- API Std 53, Well Control Equipment Systems for Drilling Wells, 5th Edition, 2018
- API RP 59, Recommended Practice for Well Control Operations, 2nd Edition May 2006, Reaffirmed: December 2018
- API Spec 6A, Specification for Wellhead and Tree Equipment, 21st Edition, 2018
- API Spec 16C, Choke and Kill Equipment, 2nd Edition 2018
- API Spec 16A, Specification for Drill-Through Equipment, 4th Edition 2018
- API Std 16AR, Standard for Repair and Remanufacture of Drill-through Equipment, 1st Edition, 2017
- API Spec 16D, Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, 3rd Edition 2018
- API RP 16ST, Coiled Tubing Well Control Equipment Systems, 1st Edition 2009, Reaffirmed 2014
- API Std 64, Diverter Equipment Systems, 3rd Edition August 2017 (Addendum 1 2018)

Supplemental References:

The following references provide additional guidance and industry best practices related to well control:

- API RP T-6, Training and Qualification of Personnel in Well Control Equipment and Techniques for Wireline Operations on Offshore Locations; 1st Edition 2002; Reaffirmed, January 2013
- API RP 54**,** Occupational Safety and Health for Oil and Gas Well Drilling and Servicing Operations, 4th Edition, 2019
- API RP 76**,** Contractor Safety Management for Oil and Gas Drilling and Production Operations, 2nd Edition, 2007
- API Bull 97, Well Construction Interface Document Guidelines; 1st Edition 2013
- API Std 65-Part2, Isolating Potential Flow During Well Construction, 2nd Edition, 2010
- API RP 96, Deepwater Well Design and Construction, 1st Edition, 2013
- NORSOK D-010, Well integrity in drilling and well operations, Rev. 4 June 2013

APPENDICES

N/A

ATTACHMENTS

N/A

DOCUMENT RECISION

This is the initial version of this standard (Rev 0 once approved and issued).

DOCUMENT APPROVER

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DOCUMENT OWNER

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Larry Kennedy, Strategic Planning Chief, GSAM

Well Control

DOCUMENT STEWARD

Larry Kennedy, Strategic Planning Chief, Gas Storage Asset Management

REVISION NOTES

Where?	What Changed?
N/A	This is a new standard

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 5

UTILITY STANDARD: TD-4880S FACILITY INTEGRITY MANAGEMENT PROGRAM

Facility Integrity Management Program

SUMMARY

This utility standard describes the Gas Operations Facility Integrity Management Program (FIMP) for Pacific Gas and Electric Company (PG&E or Company). This utility standard is applicable to all gas transmission and distribution pipeline station facilities owned and operated by PG&E. This utility standard presents the framework for the FIMP and is also the controlling document for the FIMP.

TARGET AUDIENCE

Facility Integrity Management Program and Technical Services (FIMP&TS) personnel

TABLE OF CONTENTS

Facility Integrity Management Program

REQUIREMENTS

1 Introduction

1.1 The intent of the FIMP is to contribute to the safe, environmentally responsible, reliable, and affordable operation of PG&E gas transmission and distribution facilities.

1. The FIMP consists of activities that are intended to address station-specific threats associated with safety and reliability risks to the gas pipeline system.

2. The FIMP helps ensure station equipment performs as intended without causing harm to the public, PG&E personnel, or the environment. FIMP&TS functions as a service provider of subject matter expertise on station facilities.

1.2 The framework of the FIMP consists of nine elements as specified by Pipeline Research Council International (PRCI) IM-2-1, “Facility Integrity Management Program Guidelines.” This utility standard is divided into sections applicable to each of the elements; each element is supported by a description of the general processes used by PG&E to fulfill the intent of the element. This utility standard cites other PG&E utility standards and utility procedures that provide more detailed information.

1.3 Unless otherwise noted herein, where there are conflicts between this utility standard and other procedures or instructions for this program, this utility standard must take precedence.

1.4 The FIMP Method is a series of meetings that promote the principles of Plan-Do-Check-Act to ensure continuous improvement.

1. The implementation of the FIMP Method aims to ensure that communication, risk reduction, and continuous improvement are routine.

2. The FIMP Method sessions are scheduled and tracked using the Corrective Action Program (CAP).

1.5 The *FIMP Manual* consists solely of supporting documentation for the FIMP. The *FIMP Manual* is updated as required and can be accessed through the FIMP SharePoint.

1.6 Since the assets installed at PG&E transmission and distribution station facilities differ widely in terms of function, life cycle, and applicable threats and risks, FIMP&TS personnel develop, implement, and influence activities tailored to specific station and asset types to improve the safety and reliability of the assets. These activities are risk- and asset-specific to achieve their objectives.

Facility Integrity Management Program

2 Covered Facilities

NOTE
This utility standard uses the general terms “station” and “facility” interchangeably, but these terms may have general or very specific meanings in other PG&E governance documents, federal and state codes and regulations, and industry standards and design codes.

2.1 The FIMP applies to all gas transmission and distribution station facilities owned and operated by PG&E, including:

1. Major gas facilities and regulator stations as defined by Utility Procedure TD-4430P-02, “Gas Transmission Stations Inspection, Testing, and Maintenance Procedures.”

2. Large-volume customer regulator sets, district regulator stations, and farm tap regulator sets as defined by Utility Standard TD-4540S, “Gas Pressure Regulation Maintenance Requirements for Self-Operated and Pilot-Operated Regulators.”

   - These facilities fall within the Measurement and Control (M&C) and Compression and Processing (C&P) asset families as defined in Gas Plan GP-1100, “Strategic Asset Management Plan.”

   - Low-pressure system reliefs that are located within stations and transmission large-volume customer meter set assemblies are also included within the scope of the FIMP.

2.2 The descriptions of facilities and stations within this standard must not be used as a basis to classify facilities outside the scope of this utility standard.

3 Objectives

3.1 The objectives of the departments within the FIMP&TS organization are defined in Table 1. The safe, environmentally responsible, reliable, and affordable operation of PG&E station facilities also depends on additional organizations across Gas Operations and PG&E, and those organizations are often stakeholders in FIMP activities.

Facility Integrity Management Program

3.1 (continued)

Table 1. FIMP&TS Objectives

Department	Objectives
FIMP&TS Station Services	Provide engineering and technical support to maintain and improve safety, reliability, and performance at C&P and transmission M&C facilities.
FIMP&TS Measurement Services	Advance safety, improve performance, and reduce risk for the fleet of M&C station facilities. Leverage understanding of asset condition and performance to prioritize projects and make risk-informed decisions to execute the best solutions for mitigating station-specific threats.
FIMP&TS Risk	Strategically collect and interpret data to create sustainable solutions to manage risk and advance PG&E understanding of gas transmission station facilities.

4 Data Gathering

4.1 The purpose of the data gathering element is to gather, review, and integrate station asset information to identify station-specific threats and risks and develop appropriate mitigation actions.

4.2 Station asset data generally falls into two categories: (1) static data on the assets themselves (e.g., equipment type, installation date), and (2) dynamic data (e.g., maintenance history, condition, operating performance, environmental conditions).

1. FIMP&TS personnel consult the following data sources:

   a. Asset Register: PG&E Gas Operations maintains an asset register for transmission and distribution station facilities.

   b. FIMP Field Assessments: FIMP&TS personnel conduct or coordinate field assessments as needed to collect data available in the field.

   c. As-Builts: FIMP&TS personnel review as-built records, job files, and other records related to station design and construction to collect information on station assets relevant to mitigation activities.

   d. Gas Transmission and Distribution geographic information system (GT-GIS and GD-GIS): PG&E uses GT-GIS and GD-GIS to house specific data on station characteristics and locations.

   e. Operational Data: Data available through PI and Telvent are reviewed as required.

Facility Integrity Management Program

4.3 FIMP&TS personnel identify, gather, review, and integrate relevant data as required to inform FIMP activities.

1. Consideration is given to information obtained from data on design, construction, operations, and maintenance, as well as knowledge from subject matter experts (SMEs).

2. If information in addition to that already available is needed, FIMP&TS personnel may collect additional data.

3. When data is evaluated, the following attributes may be assessed:

   - Data type (e.g., equipment make/model, piping specifications, pressure, location)
   - Data format (e.g., paper or electronic)
   - Data update frequency
   - Data completeness
   - Data quality

5 Risk, Threat, and Consequence Identification

5.1 Risk identification forms the foundation of the FIMP contribution to the safe, environmentally responsible, reliable, and affordable operation of PG&E transmission and distribution station facilities. This section outlines the process that FIMP&TS personnel must use to identify risks, threats, and consequences associated with station assets.

1. FIMP activities that are intended to mitigate specific risks may identify threats that drive the risks, identify the vulnerabilities of individual stations or groups of stations to these threats, and identify the consequences of the risks so appropriate mitigation actions can be developed.

5.2 FIMP&TS personnel use a risk register to document risks that FIMP activities are intended to address. This risk register is contained in the *FIMP Manual*.

1. Industry events must be reviewed on an annual basis, at a minimum, to determine if additional risks should be added to the register.

Facility Integrity Management Program

5.3 In the context of integrity management, threat identification can refer to the development and implementation of a methodology or algorithm that is used to make a determination if a threat is considered present on a particular asset (e.g., pipe segment) and to what extent it is present. Since FIMP activities address a range of risks on a diverse set of assets, not all threats should be considered relevant to all risks and assets.

1. FIMP activities might consider the following threat categories:
   - External corrosion
   - Internal corrosion
   - Stress corrosion cracking
   - Equipment-related failure
   - Manufacturing-related threats
   - Welding- and fabrication-related threats
   - Incorrect operations
   - Weather-related and outside force threats
   - Third-party or other excavation damage
   - Equipment obsolescence and its impact on safety, reliability, and infrastructure sustainability risks
   - Outdated or nonstandard designs
   - Operational hazards
   - Other condition-based threats (e.g., erosion, fatigue, vibration)
   - Other event-based threats (e.g., improper installation, assembly, maintenance)
   - Threats identified through Process Hazard Analyses and Pre-Startup Safety Reviews as documented by Utility Standard TD-4006S, “Process Safety Requirements”

Facility Integrity Management Program

5.4 The risks addressed by FIMP activities can result in one or more of the following consequences:

- Harm to the public or personnel working at the facility or nearby populated areas
- Loss of supply to the system or the surrounding community
- Harm to the environment
- Damage to the facility

5.5 For consequences that would be realized outside of the facility fence line or other delineating boundary, FIMP&TS may rely on consequence assessments developed by the transmission and distribution integrity management programs responsible for those assets.

6 Risk Assessment and Program Prioritization

6.1 The purpose of the risk assessment and program prioritization element is to prioritize actions within FIMP activities for the efficient allocation of resources.

6.2 FIMP activities must define the type of risk assessment or program prioritization that is appropriate for their objectives. The selected assessment or prioritization is implemented based on available data as well as threats and consequences applicable to the risk that the activity is intended to mitigate.

7 Integrity-Related Activities

7.1 Integrity-related activities include station maintenance activities, as well as FIMP activities.

7.2 FIMP&TS personnel monitor specific reliability-based metrics.

8 Performance Management

8.1 Performance management ensures that the FIMP supports continuous improvement. This section describes how performance measures are used to assess the effectiveness of FIMP activities and the FIMP Method.

8.2 FIMP activities may define one or more performance measures or key performance indicators (KPIs). Three different types of measures that may be used include the following:

1. Leading indicators suggest trends of positive improvements or deteriorating conditions; these indicators can be used to direct action to prevent incidents.
2. Lagging indicators track events that have already occurred; they offer a retrospective view and cannot be used to identify concerns prior to an event.
3. Process measures demonstrate completion or improvement in processes or procedures.

8.3 All performance measures must be simple, easy to understand, easily obtained, and auditable. Examples of performance measures employed include those associated with the strategic objectives for the M&C and C&P asset families, such as reliability-based metrics.

8.4 Performance measures for the FIMP Method consist of monitoring the cadence of the FIMP Method meetings and whether the objectives for the meetings were achieved; summaries of these meetings and opportunities for continuous improvement are documented in CAP.

9 Communications

9.1 The FIMP establishes and maintains effective communication channels to ensure that FIMP&TS, Gas Operations, and appropriate PG&E management personnel are informed on FIMP activities.

9.2 FIMP&TS personnel communicate with stakeholders as appropriate to provide current information about PG&E station facility assets and FIMP activities. FIMP activities may develop specific communications plans when appropriate.

9.3 When employees in the field discover potential hazards, they can use CAP to create a notification to FIMP&TS personnel. Utility Standard GOV-6101S, “Enterprise Corrective Action Program Standard,” contains additional information.

9.4 Roles and responsibilities to satisfy federal and state regulatory reporting requirements are described in Utility Standard TD-4413S, “Gas Regulatory Reporting Requirements.”

10 Management of Change

10.1 Management of Change (MOC), as described in Utility Standard TD-4014S, “Gas Operations Management of Change (MOC),” applies to the FIMP.

10.2 Individual FIMP activities determine the appropriate level of documentation for their MOC activities.

10.3 CAP may be used to track MOC-related documentation. Documentation may also be tracked on SharePoint sites maintained by FIMP&TS.

10.4 Changes to the *FIMP Manual* are documented in the manual itself.

11 Quality Control

11.1 The FIMP quality control includes activities related to quality management (QM), incident investigations, learning from industry events, and FIMP records.

11.2 For PG&E requirements for QM programs that assess gas transmission and distribution work performance, products, tools, and technologies as they relate to human performance, refer to Utility Standard TD-4021S, “Gas Quality Management Assessment Requirements.”

11.3 For incident investigations, refer to Utility Standard GOV-6102S, "Enterprise Cause Evaluation Standard," for the PG&E enterprise-wide framework used to identify, perform, document, track, and communicate causal evaluations.

11.4 The FIMP Method is one means by which FIMP&TS reviews data and lessons learned from industry events. Individual FIMP activities may also develop documentation on their lessons learned from significant industry events.

11.5 The master documents for the FIMP are located in the Technical Information Library, SharePoint sites, and on PG&E shared network drives.

12 Design Assurance

12.1 FIMP activities generally address existing station facilities.

1. The process for the modification or installation of new station facilities is generally initiated in response to a specific operating risk/need, including equipment obsolescence.

2. During the planning phase, known and potential risks are assessed by FIMP&TS personnel with input from SMEs.

12.2 For station designs:

1. New station designs are typically developed by project execution teams to meet project scope requirements as defined by FIMP&TS personnel and other SMEs; these designs are documented in a job package that is given to construction personnel for execution.

2. Station designs follow federal and state codes and regulations, industry standards, and PG&E governance documents (e.g., Utility Manual TD-4950M, *Gas Design Standards Manual*).

3. Existing station designs are typically documented in station facility drawings (including construction drawings and vendor drawings) and other records.

END of Requirements

Facility Integrity Management Program

DEFINITIONS

Change control: A process for evaluating and controlling modifications to facilities, operations, procedures, equipment, organization, or design activities prior to implementation, to ensure that no new hazards are introduced and that the risk of existing hazards does not increase unknowingly.

District regulator station: A pressure regulation station that includes both single and multiple stages of pressure regulation controlling pressure to a distribution main.

Farm tap regulator set: A pressure regulator set that includes single and multiple stages of pressure regulation, which controls pressure to a service line.

Facilities integrity management program (FIMP): A program intended to contribute to the safe, environmentally responsible, reliable, and affordable operation of PG&E gas transmission and distribution station facilities, exclusive of line pipe segments that are covered by the mainline integrity management programs.

Integrity: Used in the context of managing pipeline systems, a general understanding or definition of integrity has to do with quality, that is, a mechanical component meets or exceeds design specifications for an intended purpose or application.

Large-volume customer regulator set: A pressure regulation set that includes single and multiple stages of pressure regulation controlling pressure to a transmission line serving a large-volume customer, sometimes referred to as a customer primary set.

Pipeline: All parts of physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenances attached to the pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

Major Gas Facilities: Facilities that modulate gas pressure and flow or process the gas within the gas transmission system.

Regulator Stations: Facilities, other than those listed as major gas facilities, that contain pressure control devices, including monitors and reliefs and their appurtenances, which limit and control pressures in transmission lines or distribution feeder mains (DFM). Appurtenances, in this case, are any subordinate devices necessary for the pressure regulator, monitor, or relief to function properly (e.g., pilots, controls, valve positioners, pressure transducers).

Threat: An event, process, or natural phenomenon that has the potential to result in the failure of an asset's ability to perform its intended function.

IMPLEMENTATION RESPONSIBILITIES

FIMP&TS leadership will communicate the publication of this standard to the affected personnel.

Facility Integrity Management Program

GOVERNING DOCUMENT

NA

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

NA

Records and Information Management:

PG&E records are company assets that must be managed with integrity to ensure authenticity and reliability. Each Line of Business (LOB) must manage Records and Information in accordance with the Enterprise Records and Information (ERIM) Policy, Standards and Enterprise Records Retention Schedule (ERRS). Each Line of Business (LOB) is also responsible for ensuring records are complete, accurate, verifiable and can be retrieved upon request. Refer to GOV-7101S, "Enterprise Records and Information Management Standard," for further records management guidance or contact ERIM at Enterprise_RIM@pge.com.

REFERENCE DOCUMENTS

Developmental References:

American Petroleum Institute (API) 1173, "Pipeline Safety Management Systems"

Supplemental References:

FIMP Manual

Gas Plan GP-1100, "Strategic Asset Management Plan."

Pipeline Research Council International (PRCI) IM-2-1, "Facility Integrity Management Program Guidelines," December 23, 2013

Utility Manual TD-4950M, "Gas Design Standards Manual"

Utility Procedure TD-4430P-02, "Gas Transmission Stations Inspection, Testing, and Maintenance Procedures"

Utility Standard GOV-6101S, "Enterprise Corrective Action Program Standard"

Utility Standard GOV-6102S, "Enterprise Cause Evaluation Standard"

Utility Standard TD-4006S, "Process Safety Requirements"

Utility Standard TD-4014S, "Gas Operations Management of Change (MOC)"

Utility Standard TD-4021S, "Gas Quality Management Assessment Requirements"

Utility Standard TD-4413S, "Gas Regulatory Reporting Requirements"

Reference Documents (continued)

Utility Standard TD-4540S, “Gas Pressure Regulation Maintenance Requirements for Self-Operated and Pilot-Operated Regulators”

APPENDICES

NA

ATTACHMENTS

NA

DOCUMENT RECISION

NA

DOCUMENT APPROVER

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(Document contact may change after publication. To find the current document contact, see the Gas Standards and Procedures Responsibility List.)

REVISION NOTES / CHANGE LOG

Where?	What Changed?
Revision 0a	
Step 10.1 (new)	Added: “Management of Change (MOC), as described in Utility Standard TD-4014S, ‘Gas Operations Management of Change (MOC),’ applies to the FIMP.”
Step 10.2 (was Step 10.1)	Replaced “management of change (MOC)” with “MOC.”
Supplemental References	Added Utility Standard TD-4014S, “Gas Operations Management of Change (MOC)”
Revision 0	Publication Date: 01/20/2021 Effective Date: 04/01/2021
NA	This is a new standard.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 6

UTILITY PROCEDURE: TD-4125P-10 IDENTIFYING GAS TRANSMISSION ASSETS

Utility Procedure: TD-4125P-10
Publication Date: 08/03/2016, Effective Date 01/01/2018 Rev: 0

Identifying Gas Transmission Assets

Attachment 1, Gas Transmission and Distribution System Terms

Term	Definition	Source	Application Notes
Distribution center	The location at which a transmission line changes function to a distribution line. It occurs at the downstream side of the inlet fire valve to a regulator station transporting natural gas into a distribution main primarily serving non-large-volume customers who purchase gas for consumption (as opposed to purchasing for resale).	PG&E	PG&E language to clarify non-specific code language. PG&E applies this definition to district regulator stations that reduce pressure from above 60 psig to 60 psig or below as the location at which the line's function changes from transmission to distribution. The applicable upstream fire valve is the valve closest to the regulator station. If the regulator station contains pipe downstream of the upstream fire valve that is operating at or over 20% SMYS, then use a suitable downstream valve as the distribution center point (e.g., downstream block valves.)
Distribution feeder main (DFM)	A transmission pipeline that operates at a maximum allowable pressure of greater than 60 psig and is connected to other gas transmission lines on the upstream side and other distribution feeder mains on the downstream side. A DFM transports gas to a distribution center(s).	PG&E	The maximum allowable operating pressure (MAOP) of the line is used to determine the pipeline's operating pressure for the purpose of determining whether the line is a transmission line.

Identifying Gas Transmission Assets

Attachment 1, Gas Transmission and Distribution System Terms

Term	Definition	Source	Application Notes
Distribution line	A pipeline other than a gathering or transmission line. A line is a distribution line if it meets ANY of the following criteria: 1. Transports gas downstream of a distribution center whether in a Main or Service Line. 2. Operates as a farm tap.	49 CFR §192.3 plus extra clarifying PG&E criteria.	The first sentence in this definition is from Code of Federal Regulations (CFR), Title 49, Subsection (§)192.3. Criterion 1 in the second sentence clarifies that the distribution center is the location where the function of the line changes from transmission to distribution. Criterion 2 clarifies that gas service lines connected to transmission lines and operating as farm taps are classified as distribution lines, per Department of Transportation Pipeline and Hazardous Materials Safety Administration (DOT PHMSA) guidance. Note that any features of a distribution line operating at or over 20% SMYS are transmission lines.
Farm tap	A service line that is connected directly from a transmission line or gathering line to serve customers other than a Large-Volume Customer.	PG&E	This term is consistent with recent DOT PHMSA guidance. Note that more than one service line downstream of a farm tap regulator means the farm tap regulator is now a district regulator station. Also note that any features of a farm tap operating at or over 20% SMYS are transmission lines.
Gas gathering line	A pipeline that transports gas from a current production facility to a transmission line or main.	49 CFR §192.3	Exact code language. Gas gathering lines transport gas from wellheads or processing facilities to transmission lines or distribution mains.
Large-volume customer	A customer served by PG&E gas facilities which have the capability of delivering 40,000 standard cubic feet per hour (scfh) or more.	PG&E	PG&E language to clarify undefined code language. Definition uses PG&E current assets versus customer usage to improve usability of the term. The 40,000 scfh usage threshold is based on recent PHMSA interpretation letters that indicate customers using 1 MMcf per day may be considered a large-volume customer.

Identifying Gas Transmission Assets

Attachment 1, Gas Transmission and Distribution System Terms

Term	Definition	Source	Application Notes
Large-volume customer regulator set	A pressure regulation set, including both single and multiple stages of pressure regulation, which controls pressure to a transmission line serving a large-volume customer, sometimes referred to as a customer primary set.	PG&E	Defined in Utility Standard TD-4540S, "Gas Pressure Regulation Maintenance Requirements for Self-Operated and Pilot-Operated Regulators," Rev. 1 published 11/11/2015.
Main	A distribution line transporting gas that serves as a common source of supply for more than one service line.	49 CFR §192.3	Exact regulatory code language.
Service line	A distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.	49 CFR §192.3	Exact regulatory code language. Note that any features of a service line operating at or over 20% SMYS are transmission lines.

Attachment 1, Gas Transmission and Distribution System Terms

Term	Definition	Source	Application Notes
Transmission line	A pipeline, other than a gathering line, that meets ANY of the following criteria: 1. Transports gas from another transmission line, gathering line, or storage facility to any of the following: a. Distribution center b. Storage facility c. Large-volume customer that is upstream of a distribution center 2. Operates at or above a hoop stress of 20% SMYS, or is upstream of a segment of pipe operating at or above a hoop stress of 20% SMYS. 3. Transports gas within a storage field.	PG&E	This definition is set forth in 49 CFR §192.3. For consistency in operations and maintenance practices at PG&E, this revised definition clarifies that segments upstream of a segment operating at a hoop stress of 20% or more of SMYS are also considered transmission pipelines. The definition now focuses on function of line (vs. strict reliance on 20% SMYS criterion). The result is that all distribution feeder mains (DFMs) with MAOPs greater than 60 psig are now classified as transmission lines. A transmission pipeline remains a transmission line: a. Until the pipeline connects to a distribution center, a storage facility or a large-volume customer (not downstream of a distribution center). b. Remains within a storage facility. The maximum allowable operating pressure (MAOP) of the line is used to determine the pipeline's operating pressure for the purpose of determining whether the line is a transmission line.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 7

GAS SAFETY PLAN CHANGE LOG

Attachment 7
Change Log for 2022 Gas Safety Plan

This attachment lists changes in both the report narrative and the attachments between PG&E's 2021 Gas Safety Plan and 2022 Gas Safety Plan.

Section	Change Log	Change Description
I	Introduction	Updated to refer to PG&E's stand that everyone and everything is always safe.
I	Introduction	In 2021, PG&E certified with API 754:2017.
I.1	Structure of the Gas Safety Plan	Updated the three major categories of gas system risk; Loss of Containment, Large Overpressure Events, and Insufficient Capacity to Meet Customer Demand.
I.3	PG&E's Goals	Line of Sight goals are developed through the Enterprise Operating Rhythm process with a focus on eight (8) company goals; Safety, Commitments, Customer, Financial Stability, People, Relentless Execution, Risk-Informed Work & Resource Plan, and Wildfire Mitigation.
I.4	Public Safety	Three areas of continued focus: ILI, Third Party Dig-Ins, Gas Emergency Response
I.7	Natural Gas Leak Abatement Compliance Plan	The 2022 Gas Safety Plan includes the 2022-2023 Natural Gas Leak Abatement Compliance Plan.
II.1	Employee Engagement	Updated the Lean Management section to explain the evolution of huddles in to Operating Reviews.
II.2.a	Gas Safety Council	Updated charter to include IBEW and ECS union leaders as Committee members for continued partnership and collaboration.
IV.2.a	Gas Storage	Communicates progress on the sale of the Pleasant Creek facility, and reiterated the decision to retain the Los Medanos facility.
IV.2.a	Gas Storage	Updated to include CalGEM's acceptance of PG&E's modified plan to complete baseline inspections in accordance with CCR, Title 14, Section 1726.
IV.2.e	Distribution Mains and Services	Communicates completion of San Francisco cross-bore inspections.
IV.2.g	LNG/CNG	Communicated controls put in place to ensure 100% compliance of natural gas vehicle fueling customers.
IV.2.h	Data	Communicated the hiring of the Chief Data and Analytics Officer.
IV.3	Records and Information Management	Communicated closure of the Gas Transmission Record Keeping Order Instituting Investigation remedies E.05 and E.13.
IV.5.j	Leak Survey	Communicated the purchase of new leak detection units to replace aging equipment. Also expressed the use of drones with Open Path Spectrometry.
IV.5.j	Leak Survey	Introduced a new customer communication channel to mitigate the backlog of Cant-Get-Ins
IV.6	Mitigating the Risk of Loss of Supply	Added section on Winter Operations.
V.3	Workforce Training	Piloted an augmented reality program at the Gas Safety Academy.
V.5	Contractor Safety and Oversight	Communicated focus on improving contractor incident reporting, tracking, and follow up. PG&E saw a notable expansion of Strategic Partners participating and providing data.
VI	Compliance Framework	Communicated completion of all 2020 action items, and development of the 2021 remediation plan to address PWC's assessment findings.
VI	Compliance Framework	Established the Gas Organization Controls Program focused on updating and documenting key controls for high and medium risk regulatory requirements.
VII.3	SQA for Distribution and Transmission	Introduced a new metric, Quality Performance Rating, to monitor supplier's improvement of overall performance.
VII.4	Research and Development and Innovation	Focused on many new 2021 projects
Attachment	Attachment 4	Gas Manual: TD-4870M, Gas Storage Asset Management
Attachment	Attachment 5	Utility Standard: TD-4880S Facility Integrity Management Program
Attachment	Attachment 6	Utility Procedure: TD-4125P-10 Identifying Gas Transmission Assets

VERIFICATION

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 2022 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 10, 2022.

Janisse Quinones

Janisse Quinones
SENIOR VICE PRESIDENT
GAS ENGINEERING
PACIFIC GAS AND ELECTRIC COMPANY

Joe Forline

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