

APPENDIX A

***PACIFIC GAS AND ELECTRIC
GAS SAFETY PLAN***

***SEPTEMBER 30, 2014
REVISION 2
GP-1000***

PACIFIC GAS AND ELECTRIC COMPANY GAS SAFETY PLAN

*GP-1000
REVISION 2*

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Plan or "the Plan"	PG&E's Gas Safety Plan	ISO 55001	International Organization for Standardization 55001
2012 Update	The 2012 Update to the Gas Safety Plan	IST	Incident Support Team
2013 Update	The 2013 Update to the Gas Safety Plan	LNG	Liqued Natural Gas
2014 Update	The 2014 Update to the Gas Safety Plan	LOB	Line of Business
AFO	Asset Family Owner	MAOP	Maximum Allowable Operating Pressure
AGA	American Gas Association	MPR	Material Problem Reporting
API	American Petroleum Institute	NACE	National Association of Corrosion Engineers
ASME	American Society of Mechanical Engineers	OEC	Operations Emergency Center
CAP	Corrective Action Program	OII	Order Instituting Investigation
CEP	Company Emergency Plan	OQ	Operator Qualified
CFR	Code of Federal Regulations	PAP	Public Awareness Plan
CNG	Compressed Natural Gas	PAS 55	Publicly Available Specification 55
CPSD	Consumer Protection and Safety Division	PG&E	Pacific Gas And Electric Company
CPUC	California Public Utilities Commission	PHA	Process Hazard Analysis
CRM	Control Room Management	PHMSA	Pipeline and Hazardous Materials Safety Administration
DART	Days Away, Restrictions and Transfers	PSEP	Pipeline Safety Enhancement Plan
DE&R	Direct Examination and Repair	PSSR	Pre-Startup Safety Review
DIMP	Distribution Integrity Management Program	PUC	Public Utilities Commission
DPPM	Defective Parts Per Million	QA	Quality Analysis
EMR	Experience Modification Rate	QC	Quality Control
EOC	Emergency Operations Center	R&D	Research & Development
EOP	Emergency Operation Plan	RBPS	Risk-Based Process Safety
EORM	Enterprise and Operational Risk Management	REC	Regional Emergency Center
EP&PA	Emergency Preparedness and Public Awareness	RIM	Records Informaiton Management
ERW	Electric Resistance Welded	RMI	Risk Management Instruction
GERP	Gas Emergency Response Plan	RMP	Risk Management Procedure
GIS	Geographic Information System	SB	Senate Bill
GPS	Global Position System	SCADA	Supervisory Control & Data Acquisition
GRC	General Rate Case	SED	Safety and Enforcement Division
GT GIS	Gas Transmission Geographic Information System	SGA	Southern Gas Association
GT&S	Gas Transmission & Storage		
HCA	High Consequence Area	SME	Subject Matter Expert
HIRA	Hazard Identification and Risk Analysis	SMYS	Specified Minimum Yield Strength
HOA	Homeowners Association	STIP	Short Term Incentive Plan
HVAC	Heating, Ventilation and Air Conditioning	TIMP	Transmission Integrity Management Program
ICS	Incident Command System	UK	United Kingdom
ILI	In-Line Inspection	USA	Underground Service Alert
INGAA	Interstate Natural Gas Association of America	WEI	Western Energy Institute

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I. Introduction and Regulatory Summary

In October 2011, the California legislature signed into law Senate Bill (SB) 705, which declared “[i]t is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority.”¹ SB 705 was codified under Public Utilities Code (PUC) §§ 961 and 963(b)(3). PUC § 961 mandates that gas operators must go beyond what is considered “adequate” to develop and implement gas safety plans that are “consistent with best practices in the gas industry,”² and that the safety plan specifically do the following:

1. Identify and minimize hazards and system risks to minimize accidents and dangerous conditions;
2. Identify the safety-related systems that will be deployed to minimize hazards, including adequate documentation of the pipeline facility history and capability;
3. Provide adequate storage and transportation capacity to reliably and safely deliver gas;
4. Provide for effective patrol and inspection of pipeline facilities;
5. Provide for appropriate and effective system safety and controls with respect to both equipment and personal procedures;
6. Provide timely response to customer and employee reports of leaks and other hazardous conditions;
7. Include appropriate protocols for determining Maximum Allowable Operating Pressure (MAOP);
8. Prepare for, or minimize, damage from, and respond to, earthquakes and other major events;
9. Meet or exceed minimum standards for safe design, construction, installation, operation, and maintenance of gas facilities; and
10. Ensure an adequately sized, qualified, and properly trained gas corporation workforce.³

¹ Public Utilities Code § 963(b)(3).

² PUC § 961(c).

³ PUC § 961(d).

On April 20, 2012, the California Public Utilities Commission (CPUC) amended the scope of its Pipeline Safety Rulemaking to include compliance with the requirements of PUC §§ 961 and 963.⁴ The CPUC further directed each California natural gas corporation to develop and implement a plan for the safe and reliable operation of its gas pipeline facilities by no later than June 29, 2012.

On June 29, 2012, Pacific Gas & Electric Company (PG&E) filed its Gas Safety Plan (Plan or the Plan).

On July 10, 2012, California Assembly Member, Jerry Hill (now California State Senator), expressed concerns regarding the coordination and supervision of In-Line Inspection (ILI) contractors retained by California natural gas utilities. On July 20, 2012, Commissioner Florio issued an Assigned Commissioner's Ruling stating that he "share[s] the Assembly Member's Concerns" and directed "the utilities that employ in-line inspection tools towards assessing for metal loss to amend their Safety Plans to address these concerns no later than August 24, 2012."

On August 24, 2012, PG&E filed an Update to the Plan (2012 Update).

On December 26, 2012, the Commission accepted all gas system operators' gas safety plans for filing, but identified deficiencies in each plan.⁵ The Commission ordered that "[e]ach gas system operator shall, under the direction of the Consumer Protection and Safety Division [CPSD]⁶, resolve all deficiencies identified in the report approved in Ordering Paragraph 2, and each operator shall file and serve a compliance statement updating the safety plan showing how the deficiency was resolved no later than June 30, 2013." PG&E addressed the identified deficiencies in the 2012 Update and submitted an Update on June 30, 2013 (2013 Update).

PG&E's 2014 Update continues to build upon the 2012 and 2013 Plans and includes an enhanced overview of many safety-related initiatives implemented, in the process of being implemented, or planned for implementation, between June 2013 and 2015. Further details concerning the specific work PG&E plans to perform to implement the requirements of SB 705 are provided in PG&E's 2014 General Rate Case (GRC) testimony and PG&E's 2015 Gas Transmission and Storage (GT&S) rate case testimony.⁷ Specific chapters in PG&E's 2015

⁴ See Decision (D.) 12-04-010.

⁵ See D.12-12-009.

⁶ CPSD is now known as Safety and Enforcement Division (SED).

⁷ On August 14, 2014, the PUC issued its decision regarding PG&E's GRC requested revenue increase for 2014 through 2016 for gas distribution, electric distribution, electric generation systems and customer service (Application (A.) 12-11-009). PG&E is revisiting its risk-based portfolio of projects to reprioritize as necessary based on this decision. Similarly, upon final decision regarding PG&E's 2015 GT&S Rate Case (A.13-12-012) PG&E will also revisit and reprioritize as necessary, given system and resource constraints.

GT&S rate case are referred to throughout this Update. The 2015 GT&S rate case describes forward looking programs that will continue to enhance safety with emphasis on continuous improvement.

The 2014 Update reiterates PG&E's commitment and vision to become the safest, most reliable natural gas system in the nation. This vision will be achieved through the Gas Safety Excellence framework. The strategy is to deliver Gas Safety Excellence by putting safety and people at the heart of everything; investing in the reliability and integrity of our gas system; and by continuously improving the effectiveness and affordability of our processes. Strategic actions developed under this strategy are aligned under three elements of a safety management system that: (1) develop an asset management strategy to appropriately invest in the integrity and reliability of the gas system; (2) nurture a safety-first culture that places safety at the heart of everything it does; and (3) focus on process safety in all activities to minimize the possibility of high consequence events.

PG&E remains steadfast in its vision and commitment to becoming the safest, most reliable gas company in the nation. Strategic actions developed under Gas Safety Excellence include: (1) eliminating public safety related incidents; (2) being in the 1st quartile for employee and contractor safety and eliminating serious injuries; (3) meeting all reliability commitments, such as reducing unplanned outages; (4) meeting customer commitments and being in the 1st quartile for customer satisfaction; (5) being in the 1st quartile for employee engagement; and, (6) meeting all regulatory commitments. These items are discussed in more detail throughout this Update.

PG&E's vision is in alignment with the adopted safety policy of the CPUC issued on July 14, 2014, which declares the CPUC is "...striving to achieve a goal of zero accidents and injuries across all the utilities and businesses [they] regulate, and within [their] own workplace."⁸ The intent of PG&E's Plan is to provide an overarching safety strategy and framework that ensures alignment and continued improvement relative to best practices and its vision. PG&E's Plan connects the dots between all of PG&E's efforts to ensure the safety of the gas system, the public, and employees and contractors.

A. PG&E's Adherence to SB 705 (PUC §§ 961 and 963)

To ensure PG&E is implementing and continuously maintaining the Plan, a Gas Safety Executive Committee, and a Gas Safety Team (both described below) will review and update the Plan once per year, not to exceed 15 months. Updated versions of the Plan will be shared

⁸ See July 10, 2014, Safety Policy Statement adopted by the Commission at www.cpuc.ca.gov/NR/rdonlyres/967047D4-19CE-45B1-8766-057F1D7FF1CD/0/VisionZero4Final621014_5_2.pdf.

with the CPUC annually, unless otherwise directed by the CPUC. Further, all employees and contractors have access to the Plan, and the opportunity to comment on the Plan via PG&E's Corrective Action Program (CAP) (discussed in Section III.B.1).

1. Gas Safety Executive Committee

The Gas Safety Executive Committee is responsible for allocating the necessary resources to support the development, implementation, and maintenance of the Plan and its components. The Executive Committee is not a formal committee, but includes all Sr. Leadership at PG&E, who are responsible for approving and signing the Plan. The Executive Committee includes the following members:

- Executive Vice President, Gas Operations
- Sr. Vice President, Safety and Shared Services
- Sr. Vice President, Engineering, Construction, and Operations
- Vice President, Major Projects and Programs
- Vice President, Gas Transmission and Distribution Operations
- Vice President, Gas Engineering and Design
- Vice President, Asset and Risk Management
- Vice President, Financial and Resource Management
- Senior Director, Gas Transmission and Distribution Construction
- Senior Director, Gas Systems Operations
- Senior Director, Asset Knowledge & Integrity Management
- Senior Director, Gas Regulatory Strategist
- Senior Director, Field Operations
- Senior Director, Strategy and Process Excellence

2. Gas Safety Plan Team

The Gas Safety Plan Team is responsible for ensuring that the Plan reflects all components accurately and in a timely manner, including managing processes to ensure updates to any component of the Plan. The team is responsible for ensuring the Plan is reviewed and approved. This team is also responsible for ensuring appropriate communications to employees about the Plan and ensuring the Plan is available to all employees and contractors. Gas Safety Team is not a formal team, but includes representatives from the following organizations who provide insights to the information included in the Plan:

- Distribution Integrity Management
- Transmission Integrity Management
- Codes, Standards and Procedures
- Engineering & Design
- Gas Control
- Field Service
- Training
- Quality Assurance and Quality Control
- Regulatory Compliance
- Emergency Response
- Regulatory Strategy
- Asset Knowledge
- Maintenance and Construction
- Technology, Strategy & Solutions
- Local Unions
- Mapping

B. PG&E's Safety Culture and Goals

PG&E recognizes that building and maintaining a safety-first culture takes time and continued commitment. PG&E is committed to sustaining a strong safety culture. Employees are encouraged to report and act on safety concerns, which further fosters an environment of accountability and ownership where significant and essential behavioral changes can occur at all levels. PG&E's focus is to nurture a culture based on trust where employees feel comfortable speaking up, stopping jobs, sharing incidents or near hits, and learning from one another – without discipline or fear of reprisal. Additionally, PG&E is focused on reinforcing clearly defined goals and expectations, structuring incentives to align with those goals, measuring progress using industry benchmarks, and effectively communicating with customers, regulators, and the communities it serves.

Performance goals are a driving force behind management decisions and allocation of resources. In 2012, PG&E revised its performance goals and a portion of its compensation (known as the Short-Term Incentive Plan – STIP) for non-represented employees. Safety is now the single largest factor in the performance goals representing 40 percent of the total. The remaining two factors - customer satisfaction and financial performance - are weighted 35 and 25 percent, respectively.⁹ This change reinforced the importance of safety.

PG&E's 2014 STIP goals include several measures based on safety performance, customer satisfaction, and gas and electric reliability. The safety measures, which align with how PG&E will achieve its vision to become the safest, most reliable gas utility in the nation, include metrics for customer odor call response, leak repairs, gas emergency response, employee injuries, and preventable motor vehicle accidents. Customer goals are based on

⁹ 2014 weighted goals are 40% Safety, 35% Customer, and 25% Financial. In 2013, the weighted totals were: 40% Safety, 30% Customer, and 30% Financial.

customer satisfaction, which includes – among other measures – customer survey results, gas asset mapping duration,¹⁰ ILIs index,¹¹ and gas reliability.¹²

PG&E has also established safety leadership training that is, instructor led and focused on further ingraining the safety culture in its employees. This training articulates the strategy to continue to enhance the safety culture and helps leaders apply the elements that will allow them to succeed and to lead with safety by identifying the actions they will need to take to improve the safety climate at PG&E.

C. Gas Safety Excellence

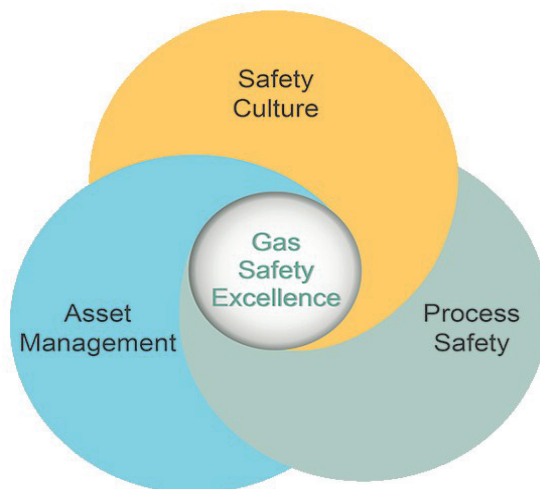
Gas Safety Excellence is PG&E's Gas Operation's strategic framework to achieve the vision of becoming the safest, most reliable gas company in the nation. This framework is designed to improve safety, manage risk, and drive continuous improvement.

The Gas Safety Excellence strategy is:

- Putting **safety** and people at the heart of everything
- Investing in the **reliability** and integrity of our gas system
- Continuously improving the effectiveness and **affordability** of our processes

Figure 1 illustrates Gas Safety Excellence's framework and how PG&E aligns its safety management system. Each section of **Figure 1** is detailed below.

**FIGURE 1 – GAS SAFETY EXCELLENCE FRAMEWORK
PACIFIC GAS AND ELECTRIC COMPANY**



¹⁰ Mapping cycle time is defined as the number of days required to update the mapping system after construction completion.

¹¹ See Section II.4.a.d).3. for discussion.

¹² See Section II.4.b. for discussion.

Asset Management

The first element in Gas Safety Excellence is a comprehensive **asset management system** that provides a holistic approach to monitoring and maintaining the health of our natural gas system and assets. With enhanced information provided by a comprehensive asset management system, PG&E can promptly identify any safety concerns, manage operational risks, and make informed decisions to improve operations. PG&E has adopted the British Standards Institute, Publically Available Specification 55-1 (PAS 55-1) and International Organization for Standardization (ISO) 55001 standard to help establish our asset management system (discussed in section II.A). Operators of these standards are able to display the following characteristics:

- Risk-based approach to managing assets
- Data-driven approach to formulating strategies and plans
- Investments focused on risk mitigating efforts

In addition, PG&E's Executive Vice President of Gas Operations, is on the American Petroleum Institute (API) advisory committee, which has drafted a recommended practice that describes a safety management system for natural gas and liquid pipelines.¹³ This recommended practice describes a safety management structure similar to asset management developed by PAS 55-1 and ISO 55001. After the draft recommended practice is approved, PG&E will take the recommendation under review and apply it to our current management system where applicable.¹⁴

Safety Culture

The second element in Gas Safety Excellence is a company vision committed to **safety culture**. Safety culture represents the alignment of human performance with the organizational strategy. Aligned goals provide employees with a clear understanding of how their work supports the goals of their department and, ultimately, the company vision. PG&E aims to inspire a culture focused on safety and continuous improvement, and recognizes the importance of strong leadership commitment. PG&E also understands a workforce that is convinced that they have full support of their leaders on safety matters will do the right thing, in the right way, at the right time, even when no one is looking. Therefore, PG&E is committed to consistently and continuously nurturing, celebrating and supporting safe behavior throughout the organization.

¹³ See, API 'Recommended Practice' 1173.

¹⁴ Similarly, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has introduced the Integrity Verification Process in August of 2013, which PG&E will review and apply when adopted.

To demonstrate its continued progress in achieving Gas Safety Excellence, PG&E worked diligently and achieved both globally recognized certifications in 2014 – PAS 55-1 and ISO 55001. In fact, PG&E is one of the first utilities in the United States to receive these types of certifications, which is awarded by an independent, third-party auditor.

Standards provided in PAS 55-1 and ISO 55001 offer many benefits to PG&E’s Gas Operations. Attaining these certifications demonstrate that PG&E’s Gas Operations has an integrated, standard-based level of maturity, from which PG&E can build upon and improve. Other benefits include a decision-making process for PG&E assets, which promotes better development of mitigation strategies for all stages of the assets lifecycle.

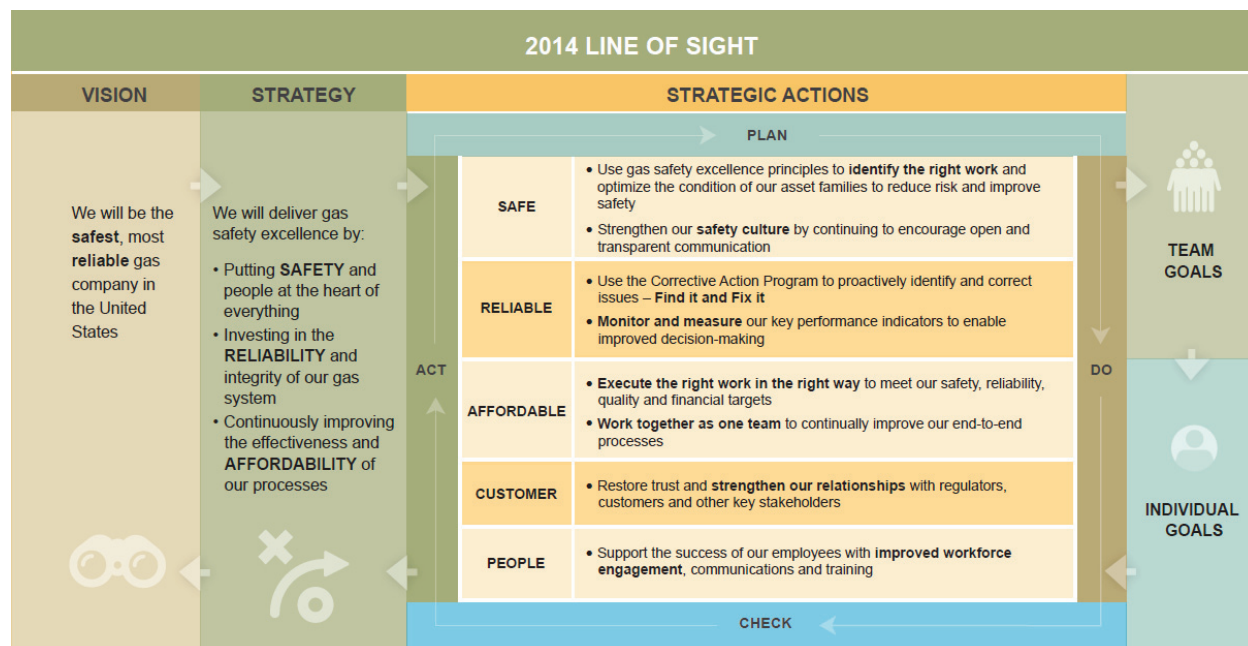
PG&E plans to achieve Gas Safety Excellence and continuous improvement through adopting the ‘Plan–Do–Check–Act’ approach, as shown in **Figure 2**.

**FIGURE 2 – ‘PLAN-DO-CHECK-ACT’ APPROACH
PACIFIC GAS AND ELECTRIC COMPANY**



An important component of being able to make and sustain safety improvements in the organization is the ability to connect our strategies through the entire organization. By introducing and embedding Line of Sight goals (**Figure 3**), the connections are made clearer. Line of Sight goals are developed annually in a process that highlights the key strategic actions that if delivered, will advance the strategy and performance of the business to continue to make progress towards achieving PG&E’s vision. These goals are linked upwards to the overall strategy of the company – being safe, reliable and affordable, and then through a cascade process, linked to gas operations departments, teams, and individuals. Line of Sight goals will remain an important vehicle in delivering Gas Safety Excellence over the coming years.

**FIGURE 3 – LINE OF SIGHT GOALS
PACIFIC GAS AND ELECTRIC COMPANY**



Process Safety

The third element in Gas Safety Excellence is a robust plan to strengthen **process safety**.¹⁵ Process Safety is utilized to reduce the likelihood of potential low frequency, high consequence incidents. PG&E is focusing on embedding process safety principles to ensure safe management of assets across their entire life cycle including design and engineering of facilities, maintenance of equipment, effective control points and procedures and training.

To promote process safety, PG&E is leveraging a Process Safety Management System (Figure 4), which includes engineering and administrative controls.

¹⁵ This system is based on the elements of Process Safety developed by the Center for Chemical Process Safety (CCPS), a branch of the American Institute of Chemical Engineers (AIChE).

**FIGURE 4 – PROCESS SAFETY MANAGEMENT SYSTEM
PACIFIC GAS AND ELECTRIC COMPANY**



Source: The Process Safety Accident Prevention Foundation Blocks from CCPS, "Guidelines for Risk Based Process Safety", 2007, AIChE, NY

To stimulate Process Safety Management excellence, PG&E implemented a Risk-Based Process Safety framework, which recognizes that all hazards and risks are not equal; and advocates that more resources should be focused on more significant hazards and higher risks. PG&E is making diligent effort to operationalize process safety, understand hazards and risks, manage risk, and learn from experience.

PG&E has deployed Hazard Identification and Risk Analysis (HIRA), and Process Hazard Analysis (PHA) methodologies in order to evaluate risks within the gas operations activities and assets. Both HIRA and PHA are used to identify hazards and evaluate risk of assets, throughout their life cycle, to make certain that risks to employees, the public, the environment, and/or the assets are consistently and mitigated.

In addition, PG&E has deployed the Pre-Startup Safety Review (PSSR) program, which helps ensure that risks have been identified and addressed; that there is agreement on all startup requirements including training, drawings, spare parts and operating procedures before operationalizing new equipment and facilities; and that there are alternatives to address any issues. In 2014, PG&E conducted a number of HIRA, PHA, and PSSR's on its systems to

augment our understanding of hazards and risks to enable effective planning and implementation of layers of mitigating strategies.¹⁶

II. Achieving Safety through Asset Management

A. Publicly Available Specification (PAS) 55 and International Organization for Standardization (ISO 55001)

PG&E Gas Operations has achieved the best practice asset management certifications offered by the British Standards Institute under its PAS 55-1 and the recently released ISO 55001 standards through the ISO, a world class standard for asset management. Both provide an objective certification and an independent assessment of the completeness of the asset management process. Attaining these certifications is a major milestone of achieving Gas Safety Excellence. PG&E will need to continuously improve in order to maintain the certifications on an ongoing basis

PAS 55-1 was first established in 2004, by a cross-section of utility and asset management experts in response to demand from regulators and the industry for an asset management standard that required objective assessment. PAS 55-1 was adopted in the United Kingdom (UK) by the UK's Office of Gas and Electric Markets to ensure that public utility and infrastructure assets were being managed safely in a risk-informed manner. It is currently used by over 50 public and private organizations in ten countries and fifteen industry sectors. ISO 55001 was created by the international community as a response to the significant global interest in asset management. ISO 55001 is based in large part on the PAS 55-1 standard.

Both PAS 55-1 and ISO 55001 standards specifically require evidence of alignment between risk-informed plans and execution of those plans. They ensure that the principles of safety, life cycle planning, risk management, cost/benefit, asset knowledge, customer focus and sustainability are actually delivered within the day-to-day activities of designing, operating, maintaining, and the eventual retirement/renewal of those assets and that the organization is continuously learning and improving.

To meet these standards, PG&E developed a strategic plan for the organization and then systematically, and in a coordinated fashion, implemented the plan to sustainably manage risks, assets and asset systems, asset performance, and expenditures over their defined life cycles. The standards assure alignment between PG&E's integrated planning activities, the gas asset management policy, standards, objectives, asset management plans, the risk register, and specific work plans.

¹⁶ There are twenty elements to Process Safety Management which is discussed in Section III.

PAS 55-1 and ISO 55001 standards require the creation and rollout of a strong line of sight between the highest level organizational objectives to the activities of employees in the field. They require that PG&E's management team reviews, at least annually, the results of communications, participation and consultation with employees and other stakeholders. The third-party certification auditors will audit PG&E and its employees' understanding of safe operations, maintenance and improvement processes, and verify that there is a process in place to continuously identify, address and improve issues.

PAS 55-1 and ISO 55001 standards encourage organizations to nurture a culture of continuous improvement; in order to maintain accreditation it is imperative that the company is able to demonstrate improvements in all aspects of the Asset Management System. To maintain certification, PG&E will undergo annual independent audits of its asset management processes, as well as an independent recertification audit every three years. PG&E is committed to maintaining these certifications and meeting the high international standards that the PAS 55-1 and ISO 55001 standards require, and their underlying principles of sustainable safe operating processes and continuous improvement.

B. Risk Management Process

1. Enterprise and Operational Risk Management

PG&E is using a comprehensive enterprise and operational asset and risk management process. PG&E's Enterprise and Operational Risk Management (EORM) plans allow PG&E to manage assets and risks at both an enterprise and operational level. The enterprise risks are those that could threaten the viability of the company and may span multiple lines of business (LOB). Operational risks arise from assets, people, processes and technologies within specific LOBs within the company, such as the Gas Operations LOB. By assessing and managing risks from both points of view, we can better manage the interdependencies and drive for consistency among LOBs. In addition, this process increases senior management and board engagement in risk-based decision-making by involving them in decisions as the process unfolds, and gives those individuals charged with managing specific assets line of sight to other risks in the enterprise.

Potential key risks are identified by the LOBs and reviewed by the senior officers to develop the 2014 enterprise-level risks that are shown in alphabetical order in **Table 1**.

**TABLE 1 – 2014 ENTERPRISE-LEVEL RISKS
PACIFIC GAS AND ELECTRIC COMPANY**

Business Model
Risk associated with external forces that could affect the viability of the Utility's business model, including the fundamentals that drive the overall objectives and strategies that define that model. This includes changing customer demands, competitor risk, changing technology, changes in the industry, and changes in the regulatory environment.
Catastrophic Pipeline Failure (Gas Operations System Safety)
Rupture of transmission pipeline may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage. This includes ruptures that may be caused by internal or external corrosion; manufacturing-related defects in older seam types; weather-related and outside forces and land movement; and welding/fabrication-related pre-1962 construction with land movement.
Cybersecurity
An intentional/unintentional loss of control of information and systems used for gas and electric operations and business operations may result in life safety events; operational reliability impacts; privacy and intellectual property theft; or revenue and reputation loss.
Emergency Preparedness and Response to Catastrophic Events
The risk of ineffective preparation for or poor execution of a response to a catastrophic emergency may result in extended outages, regulatory action, and reputational damage.
Environmental (Chromium Remediation)
Failure to adequately manage the remediation of Chromium 6 groundwater contamination from historic operations and manage stakeholder relationships could lead to increased remediation costs, perceived public health concerns, regulatory fines, and reputational damage.
Failure of Substation – Catastrophic (Electric Operations System Safety)
Complete loss of substation may result in significant wide-scale/prolonged outages, public or employee safety issues, significant environmental damage, or significant property damage.
Hydro System Safety – Dams
A failure of a PG&E dam that may result in significant damage to third parties, the environment, and PG&E.
Nuclear Operations and Safety – Core Damaging Event
Nuclear reactor core-damaging event with the potential for radiological release at the Diablo Canyon Power Plant due to natural disaster, equipment failure, or some other significant event.
Wildfire (Electric Operations System Safety)
PG&E assets may initiate a wild land fire that is not easily contained and that endangers the public, private property, or sensitive lands, and/or leads to long-duration service outages (focus is on overhead electric assets; Electric Operations internally uses the terms "wild land fire" and "wildfire" interchangeably).

The Gas Operations organization has adopted a risk management process that provides a repeatable and consistent method to identify, assess, rank, and mitigate risk. This risk management process is an element of PG&E's Integrated Planning Process to ensure risk informs the identified strategies, which in turn drives the allocation of resources. Gas

Operations is applying the risk management framework (**Figure 5**) and roadmap built by the EORM team to work towards achieving best-in-class operational risk management. As part of the risk management framework, the inherent risk, current residual risk, and the forecasted residual risk (for proposed mitigations) are identified. The enterprise-level risk with the most significant impact on gas operations was identified as a Catastrophic Pipeline Failure, as part of the 2014 risk assessment process. The risk review and refresh process is performed at the enterprise level on an annual basis.

**FIGURE 5 – RISK MANAGEMENT FRAMEWORK
PACIFIC GAS AND ELECTRIC COMPANY**



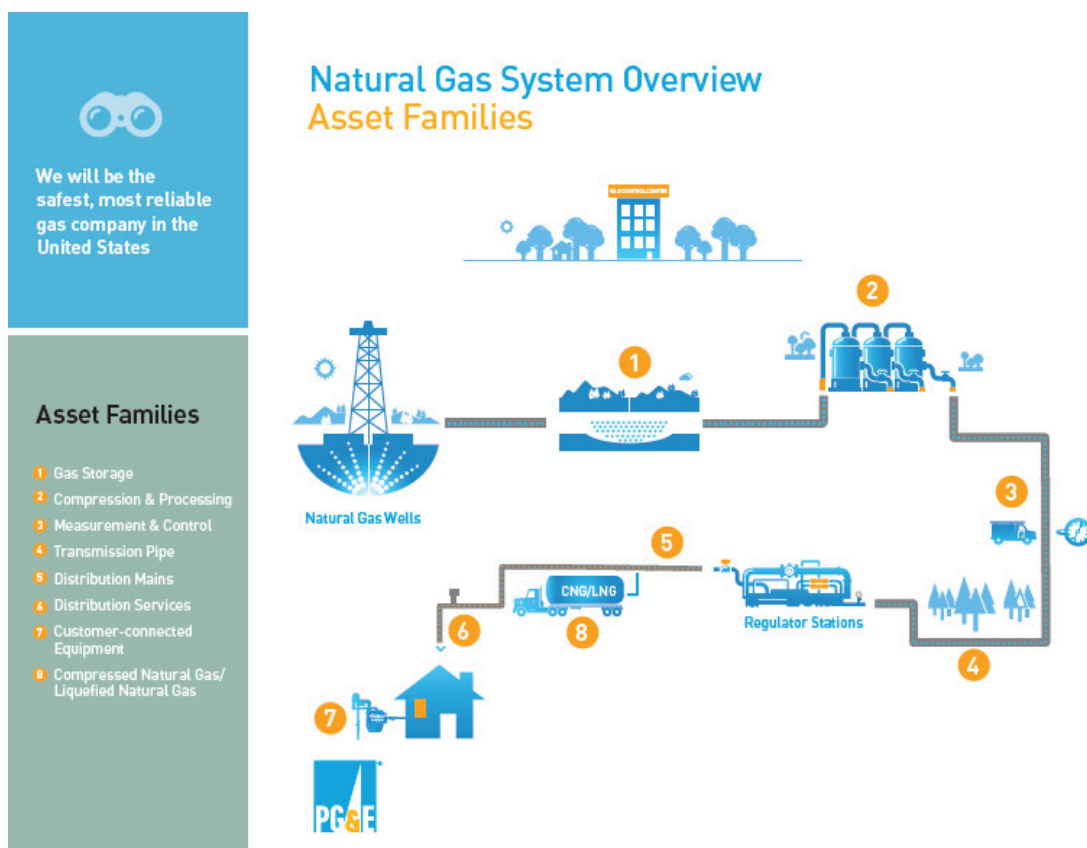
Gas Operations has established a Risk and Compliance Committee, chaired by the Gas Operations Executive Vice President. Under the guidance of the Risk and Compliance Committee, Gas Operation’s Risk Management team, with the input of industry experts, utilizes a relative risk scoring system, based on EORM guidelines and tools, to quantify likelihood and consequence of failures across all gas assets, resulting in relative risk scores for all identified operational risks.

These risks are managed within and across eight Gas Operations asset families. Each asset family has an Asset Family Owner (AFO) who is responsible for working with subject matter experts (SME) to identify and manage risks and develop risk-based asset management plans.

2. Asset Family Structure

As part of PAS 55-1 and ISO 55001, PG&E identified eight asset families within Gas Operations. **Figure 6** illustrates the interconnection between each asset family. Because these assets can face different types of risk, the asset family structure recognizes and manages these differences yet drives consistency in the way PG&E thinks about and addresses risks. Each asset family has an AFO who is responsible for working with SMEs to identify and manage risks within their asset family, and develop risk-based asset management plans. The overarching objectives of this asset management process include understanding, maintaining/improving asset condition; achieving compliance with regulatory requirements; improving and reducing management of unplanned outages; improving emergency response capabilities; and improving completeness and accuracy of our digital asset data. The Asset Family strategy and objectives are detailed in **Attachment 1**.

**FIGURE 6 – ASSET FAMILY STRUCTURE
PACIFIC GAS AND ELECTRIC COMPANY**



PG&E documents the management of each asset family through an Asset Management Plan. The Asset Management Plan for each asset family describes: the physical characteristics and location of the assets, asset health indices reflecting the condition, the risk assessment process, the overall maturity, comprehensiveness and quality of data used to assess the threats

and risks, and a vision for the desired state of the assets. The plan identifies the potential threats particular to that family of assets as well as the mitigation programs to reduce the risks posed by such threats. The Asset Management Plans also include Key Performance Indicators, which are metrics intended to measure progress and improvement in asset performance and the effectiveness of mitigation programs. These Asset Management Plans are living documents, evolving as new data becomes available.

The next sections describe the eight asset families and how their work aligns with safety. This Asset Family structure is also described in detail in 2015 GT&S Rate Case.¹⁷

a. Transmission Pipe

The Transmission Pipe asset family consists of line pipe used in transporting natural gas as well as related major components, such as valves. PG&E's Transmission Pipe asset family includes pipe that transports gas from receipt points into PG&E's natural gas transmission system until the gas is delivered into PG&E's natural gas distribution system and falls under PG&E's Transmission Integrity Management Program (TIMP). TIMP governs how PG&E assesses performance and identifies risks that need mitigation. It is a core foundation of PG&E's ongoing efforts to provide safe and reliable service, consistent with industry best practices, and is based on the federal TIMP regulation as set forth in 49 Code of Federal Regulations (CFR) 192, Subpart O.

Historically, PG&E identified 5,808 miles¹⁸ of its line pipe to be transmission. As we prepared for PAS 55 certification by separating assets into asset families, PG&E reviewed the categorization of our transmission and distribution assets. In addition, PG&E reviewed this categorization in light of 49 CFR 192.3 and recent PHMSA (U.S. Department of Transportation (DOT)) interpretation letters. As a result, PG&E defined an additional approximately 920 miles of line pipe to be transmission rather than distribution. This brings the total of transmission pipe to approximately 6,750 miles.

The federal code treats pipe and related assets as belonging to transmission—rather than distribution—if it meets any one of three prongs. These are:

- i. A change of function from transporting gas to delivery to a distribution center or to a large customer not downstream of a distribution center;

¹⁷ 2015 GT&S Rate Case Application (A.) 13-12-012.

¹⁸ Based on the 2012 PHMSA 7100 report.

- ii. Operating at a hoop stress of 20 percent or more of Specified Minimum Yield Strength (SMYS);¹⁹ or
- iii. Transporting gas to or within a natural gas storage field.

For PG&E, the main change in this reclassification revolves around the physical location of the “distribution center” where the function changes from transporting gas to distributing it for two or more customers. It involves line pipe segments and related components. The change means these segments will be included on a more frequent maintenance and inspection schedule and, depending on the density and types of buildings in close proximity to these segments, may qualify for inclusion in the Transmission Integrity Management Program. It also ensures that pipeline segments are treated as belonging to transmission or distribution for all purposes, not just for integrity management purposes.

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. Some of the plans objectives include the following:

- Expand rigorous integrity management principles beyond High Consequence Areas (HCA);
- Shift primary method of assessing HCAs from External Corrosion Direct Assessment to ILI based integrity assessments;
- Shorten pipeline isolation and response times in populated areas;
- Eliminate over-pressure events;
- Enhance public awareness and emergency response capabilities;
- Implement pipeline pathways to achieve a delineated right-of-way, and continue to evaluate, refine and improve threat assessment and mitigation procedures;
- Maintain and further develop our core monitoring and preventative maintenance programs; and
- Maintain our knowledge on our assets, allowing for informed, risk based decision making.

The transmission asset management plan describes these objectives in detail and is included as **Attachment 2**. A more in-depth discussion of specific programs, such as ILI, Direct assessment, and the addition of the approximate 920 transmission miles, prioritized for 2015 are also discussed in Chapter 4 of PG&E’s 2015 GT&S rate case.

¹⁹ SMYS means the Specified Minimum Yield Strength for steel pipe manufactured in accordance with a listed specification. This is a common term used in the oil and gas industry for steel pipe used under the jurisdiction of the DOT. It is an indication of the minimum stress a pipe may experience that will cause plastic (permanent) deformation.

b. Distribution Mains and Services

The Gas Distribution Asset Families include the Distribution Main Asset Family and the Distribution Service Asset Family, which fall under PG&E's Distribution Integrity Management Program (DIMP). Regulations govern how PG&E inspects and maintains more than 42,000 miles of pipe, 3.3 million gas service connections, and other gas distribution assets. The DIMP governs how PG&E assesses performance and identifies risks that need mitigation. It is a core foundation of PG&E's ongoing efforts to provide safe and reliable service, consistent with industry best practices, and is based on the federal DIMP regulation as set forth in Title 49 of the Code of Federal Regulations – Transportation (49 CFR) 192.1007.²⁰ The DIMP applies to all gas distribution assets and facilities.

The Gas Distribution Mains and Services Asset Management Plan summarizes risks to PG&E's gas distribution system and proposes mitigations to address those risks. The distribution asset management plan describes the roadmap for achieving the asset management objectives. Some of the plans objectives include the following:

- Improving leak performance;
- Reducing and managing the leak backlog;
- Evaluating cathodic protection on metallic distribution mains;
- Reducing size of emergency shutdown zones;
- Reducing third-party dig-ins;
- Reducing major over-pressure events
- Ensuring DIMP regulatory compliance;
- Effectively scheduling planned outages in advance; and
- Improving completeness and accuracy of digital data.

The distribution asset management plan describes these objectives in detail and is included as **Attachment 3**.

c. Gas Storage

The Gas Storage Asset Family includes PG&E's owned and operated underground gas storage fields. The objective of the plan is to identify the threats, risks, and condition of the asset, and identify programs to reduce the risk for all components contained within the boundaries of the Gas Storage asset family.

The Gas Storage Asset Management Plan describes the roadmap for achieving the asset management objectives. Some of the plans objectives include the following:

- Assess and monitor field and storage wells;

²⁰ CFR 192, Subpart P, published on December 4, 2009 at 74 CFR 63929.

- Approval of the well integrity management program and risk assessment process by the Department of Oil, Gas and Geothermal Resources;
- Evaluate field and well performance in real time;
- Understand health of control system on overflow controls and monitoring;
- Utilize electronic data to understand well condition on real time basis; and
- Capture existing well files on well integrity in electronic database.

The gas storage management plan describes these objectives in detail and is included as **Attachment 4**.

d. Compression & Processing

The Compression and Processing Asset Family includes the compressor units and associated equipment installed at nine compressor stations; and, compressor units and gas processing facilities installed at three underground storage facilities. Additionally, this asset family includes gas processing and conditioning equipment installed at four transmission dehydration stations, as well as, gas odorizers and associated equipment installed systemwide.

The Compression and Processing Asset Management Plan describes the roadmap for achieving the asset management objectives. Some of the plans main objectives include the following:

- Improve performance for completing and closing corrective work;
- Ensure that critical documents required for compression and processing are completed;
- Implement site-specific corrosion monitoring programs to enhance existing programs;
- Investigate and incorporate process safety concepts;
- Implement program to improve visibility of condition and criticality of assets to reduce the number of unscheduled shutdowns of compressor units;
- Develop and implement equipment obsolescence program;
- Develop best in class guidance document and Maintenance & Operations training on work procedures and specialized gas processing equipment; and
- Develop robust metrics and targets, and issue the Gas Transmission Engineering & Design Manual to provide uniformity of installed systems.

The compression asset management plan describes all objectives in detail and is included as **Attachment 5**. As part of continuous improvement and safety, PG&E has requested funding for multiple projects such as Engineering Critical Assessment, rebuilding aging infrastructure,

replacements of certain compressor units, mitigating threats by enhancing record keeping and physical security, among other programs, in Chapter 6 of its 2015 GT&S rate case.

e. Measurement & Control

The Measurement and Control Asset Family includes transmission and distribution stations that control pressure and gas measurement equipment, and are critical to providing safe and reliable delivery of natural gas.

The Measurement and Control Asset Management Plan describes the roadmap for achieving the asset management objectives. The objectives of this plan are similar to the compression and processing objectives that are included above in **Section d**. The Measurement and Control asset management plan describes its objectives in detail and is included as **Attachment 6**. Similar to Compression and Processing above, PG&E has requested funding for multiple projects in Chapter 6 of its 2015 GT&S rate case related to transmission related Measurement and Control equipment.

f. Customer Connection Equipment

The Customer Connection Equipment Asset Family is comprised of over 4.4 million billing 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 Connection Equipment Asset Management Plan describes the roadmap for achieving the asset management objectives. Some of the plans objectives include the following:

- Reduce and manage leak backlog;
- Identify and remove problematic customer regulators;
- Reduce unplanned meter change-outs;
- Complete meter protection program;
- Execute meter change plan in accordance with regulatory requirements;
- Maintain meter accuracy within industry accepted standards; and
- Maintain complete and quality data.

The customer connected asset management plan describes its objectives in detail and is included as **Attachment 7**.

g. Compressed Natural Gas/Liquefied Natural Gas

The Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) Asset Families consist of (1) portable equipment that can store and transport gas on public highways, and

deliver this gas to PG&E or PG&E customer pipeline systems to supplement or substitute for normal pipeline flowing supplies; and (2) LNG and CNG vehicle fueling stations that are part of the natural gas delivery system.

The portable equipment falls into two basic categories:

- Portable gas supplies in the form of LNG and CNG in highway truck trailers.
- Portable injection equipment which allows the delivery of gas from portable supplies equipment to PG&E customers or pipeline systems.

The LNG/CNG Asset Management Plan describes the roadmap for achieving the asset management objectives. Some of the plans objectives include the following:

- Minimize threats that lead to the risk of loss of containment, and to reduce health and safety risks;
- Minimize threat of equipment failure; and
- Reduce risk of unavailability of the portable system service delivery.

The CNG/LNG plan describes its objectives in detail and is included as **Attachment 8**.

The LNG and CNG Fueling Station Asset Management Plan describes the roadmap for achieving the asset management objectives. Natural gas is applied to the stations by PG&E's distribution pipeline network, and the stations supply gas as fuel to PG&E and third-party vehicles. This asset management plan is included as **Attachment 9**.

3. Understanding Risks to the Asset Families

a. Risk Framework

There are three principal, overarching risks for Gas Operations: (1) loss of containment; (2) loss of supply and service; and (3) inadequate response and recovery:

- 1) **Loss of containment:** Risk that gas will escape the system in an uncontrolled manner. PG&E's plan to mitigate this risk is driven by its operational risk assessment and integrity management programs including Distribution Integrity Management, Transmission Integrity Management, and Damage Prevention, among others. These programs focus on identifying ways to mitigate the risks associated with identified "threats," including corrosion, natural forces, excavation damage, other outside force damage, material, weld or joint failure, equipment failure, and incorrect operation.
- 2) **Loss of supply and service:** Risk that PG&E will be unable to deliver natural gas to one or more customers. PG&E's plan to mitigate this risk is largely driven by Systems Operations and by the new Gas Control Center. Systems Operations is

focusing on three risk mitigation drivers: (1) process; (2) visibility; and (3) control. PG&E will be instituting new processes and installing a significant number of additional monitoring and control points to mitigate these risks. In addition to Systems Operations, PG&E's efforts to mitigate this risk include investing in capacity, including new business, investing in training so that people execute work properly and investing in technology.

- 3) **Inadequate response and recover:** Risk that, if there is an unplanned loss of containment or loss of supply or service, PG&E will not be able to adequately respond to make the situation safe. Mitigating this risk involves proper training, a robust emergency response plan including an established and structural Incident Command System (ICS), and coordination both internally as well as with external first response agencies.

As part of PG&E's evaluation of pipeline safety relative to Loss of Containment, potential threats are considered as outlined in the American Society of Mechanical Engineers (ASME), publication B31.8S. This standard is specifically designed to provide the operator with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes. Gas Operations applies the processes and approaches within this Standard to each of the eight asset families.

The threats considered include those listed in ASME B31.8S, as identified below:

- 1) Time dependent threats (which are threats that potentially increase over time, such as corrosion).
- 2) Stable or "resident" threats (which are threats that are present, or inherent to the asset, such as manufacturing or construction defects, but do not pose a threat unless acted upon by outside forces).
- 3) Time independent threats (which are threats such as third party excavation damage, incorrect operations, or weather related and outside forces such as land movement or terrorism).

The results of the threat assessments described in **Table 2** below are used to identify and prioritize the mitigation programs for the gas system.

**TABLE 2 – THREAT ASSESSMENT IDENTIFICATION
PACIFIC GAS AND ELECTRIC COMPANY**

	Time-Dependent Threats <i>"The threat level may grow over time if unchecked"</i>			Resident Threats <i>"The threat is inherent but does not grow over time unless acted upon by pressure or external load"</i>			Time Independent Threats <i>"The threat exists outside of the continuum of time"</i>		
	External Corrosion	Internal Corrosion	Stress Corrosion Cracking	Manufacturing Related	Construction / Fabrication Related	Equipment Related	Excavation Damage	Incorrect Operations	Weather & Outside Forces
Primary CAUSES	Coating Degradation and Inadequate Cathodic Protection	Gas Quality	Coating Degradation, Pipe Surface Condition, Environment, Stress & Fluctuations, Discharge Temperature	Long-seam Defects, Pipe Defects	Girth Welds, Coupled Pipe, Wrinkle Bends, Branch Connections	Gaskets Relief Values / Regulators	1st, 2nd and 3rd Party	Human Error, Inadequate Training, Failure to Follow Procedures	Weather-Related Events, Ground Movement, Terrorism
Primary PREVENTION PRACTICES	Cathodic Protection	Gas Quality Monitoring	Cathodic Protection	Pipe Specification	Construction Practices	Preventative Maintenance	Excavation Observation and Patrolling	Operating Procedures	Continuous or Event-based Surveillance
	Close Interval Survey	Site-Specific Plan	Field Inspections	Inspection During Manufacturing	Inspection During Construction	Inspection During Maintenance	Use of One Call System	Training & Development	
MITIGATION PRACTICES (Assessment technology)	In-line Inspection Direct Assessment	Operational Pigging	Pressure Testing	Mill Pressure Testing	Pressure Testing	Patrolling	Locating & Marking	Operator Qualification	Emergency Preparedness
		In-line Inspection	Direct Assessment	Pressure Testing	Patrolling	Monitoring Pressure & External Loads	Excavation Monitoring	Audits	Slope Monitoring & Stabilization
	Pressure Testing	IC Direct Assessment	Coating Surveys (DCVG and ACVG)	Monitoring Pressure & External Loads	Monitoring Pressure & External Loads		Public Awareness	SCADA/Network Visibility	Local land movement evaluation
	Coating Surveys (DCVG and ACVG)	EM Coupon Monitoring	In-Line Inspection	In-line Inspection	In-line Inspection		In-line Inspection		In-line Inspection
		Pressure Test	Discharge Temperature						Cyber security

b. Risk Register

Using a standardized methodology in accordance with the EORM guidelines, the likelihood of failure and consequence of failure are determined and used to calculate the risk scores. In a series of workshops led by the risk management team, the risks scores and mitigating actions are developed by AFO's and SME's based on available internal and external data and expert (AFOs and SMEs) input. To ensure accuracy and consistency, the risk scores are calibrated within each Asset Family, across all asset families within Gas Operations, and at the enterprise level across all LOBs. These calibration sessions are conducted to ensure that the ranking and scenarios of the identified and evaluated risks are consistent across Asset Families and LOBs. This ranking is documented in a Risk Register, which is maintained in a central location (such as the Enterprise Compliance Tracking System) for further updates, review, reference, and reporting. Gas Operations communicates its top risks across the business (based on the Risk Register scoring) to PG&E's executive leadership team in other LOBs at the Integrated Planning Process "Risk and Compliance Session" typically in the first to second quarter timeframe of each year. This process, referred to as "Session D," endeavors to ensure that the highest risks to the business, and mitigation of these risks, are reflected in the corporate strategy and the

executable investment plans as part of Session 1 and Session 2.²¹ Risks, including the key risks for each asset family identified during Session D, are captured within the asset management plans, mitigation programs, and work projects.

As the result of the risk refresh process and the 2014 Session D, the Gas Operations Risk Register identified 200 enterprise, operational, compliance and shared risks. The top 10 Gas Operations risks (based on the current residual Risk Register scoring) are shown in **Table 3**. For a more in depth discussion on PG&E’s risk register see Chapter 2A Supplemental Testimony from PG&E’s 2015 GT&S rate case.²²

**TABLE 3 – OPERATIONAL RISKS – TOP 10
PACIFIC GAS AND ELECTRIC COMPANY**

Risk #	Risk – Listed in Descending Order
1	Catastrophic Pipeline Failure - External Corrosion (System Safety)
2	Catastrophic Pipeline Failure - Welding/Fabrication Related - Pre-1962 Construction with Land Movement (System Safety)
3	Catastrophic Pipeline Failure - Internal Corrosion (System Safety)
4	Catastrophic Pipeline Failure -Manufacturing Related Defects - Older Seam Types (System Safety)
5	Catastrophic Pipeline Failure - Weather Related & Outside Forces - Land Movement (System Safety)
6	Cyber Security
7	Third Party/Mechanical Damage (System Safety)
8	Excavation Damage - Cross Bore
9	Material or Weld - Plastic
10	Excavation Damage, Third Party - Rupture At-Fault due to mismarking by PG&E

²¹ Session 1 is the first session of the Integrated Planning process in the year and includes an overview of each line of business’ strategy and goals over a three - five year timeline to mitigate the risks identified during Session D process. Session 2 is the second session and involves the work execution planning that provides the allocation of budget and resources to execute the required work for the following year to mitigate the risks identified during the Session D process.

²² 2015 GT&S Rate Case Supplemental Testimony served July 15, 2014.

4. Mitigation Programs to Reduce Risk

This section describes programs PG&E has in place to mitigate risks to its pipeline system.

a. Mitigating Loss of Containment

a) Damage Prevention

Damage Prevention is an end-to-end process that includes the field location of underground facilities as requested through the Underground Service Alert (USA) One-Call system, USA ticket management, investigations associated with dig-ins, and damage claims. The marking of underground utilities is governed by California Government Code 4216 and the process is driven by industry best practices.²³

Damage Prevention consists of multiple processes working together to help prevent damages from all excavation activities, including legislative support. Activities include Public Awareness, Dig-In Prevention, and Locate and Mark. PG&E's Damage Prevention processes are reviewed annually. Each process is described in detail in the next sections. Damage prevention program also addresses and helps mitigate Risk #7 and #10 in Table 3 above.

1) Public Awareness

Public Awareness is another key process to ensure safety, and consists of educating customers and other key audiences regarding excavation rules, laws, and best practices. Efforts in this area include, but are not limited to, sending bill inserts in the mail, making education links available on email bill pay, sending individual separate mailers, running ads in newspapers and on the radio, conducting companywide campaigns for Call 811 Before You Dig, and attending USA S.A.F.E. events that involve educating excavator companies of safe digging practices and recommendations. PG&E's Public Awareness Plan (PAP), documented in PG&E's Risk Management Plan 12 (RMP-12) (**Attachment 10**), includes performance metrics and guidelines for evaluating the plan and for continuous program improvement.

The primary objectives of the PAP include awareness, damage prevention, and emergency response readiness. On an annual basis the Public Awareness Administrator or designated resource, conducts a review and develops a written report that summarizes program implementation details and outreach efforts and provides an assessment of message comprehension and understanding and a summary of stakeholder feedback collected during the year. The report also provides details regarding any notable fluctuations compared to previous years. Stakeholder feedback may include:

- Survey data collected at meetings from emergency responders and excavators;

²³ Pursuant to 49 CFR §192.614, PG&E is required to have a Damage Prevention Program.

- Stakeholder feedback collected through phone surveys, mail surveys, online surveys, focus groups or stakeholder interviews; and
- Pre-Testing—reports from focus groups, employee interviews or online panels; conducted to gauge message clarity and understandability of program materials.

The results document the number of third-party incidents during the previous year, near hits, and any additional data tracked by Damage Prevention that is helpful in understanding excavator needs, issues and trends. Planned program changes for the upcoming years are based on recommendations provided by the Public Awareness Program Committee, employees or vendors that support the program will also be included.

II) Dig-In Prevention

Dig-In prevention consists of determining the root causes of excavation damage to PG&E's facilities, identifying process improvements to reduce damages, and actively pursuing cost recovery for damage from responsible excavators through PG&E's claims department, and other enforcement processes. Process improvements currently in progress include:

- Integration of “caution tape” into PG&E's construction standards, which provides excavators with a tell-tale sign that gas facilities are below;
- Training of internal excavators to conduct a “pre-sweep” prior to excavation, ensuring that all structures are identified;
- Deployment of PG&E's “Damage Prevention Manual” to provide clearer instruction around critical steps, including troubleshooting of “difficult to locate” facilities;
- Deploying two senior-level investigators to oversee and enhance PG&E's ability to investigate dig-ins;
- Developing a “Gold Shovel Standards” program to reward contractors who practice safe excavation, and deploying a “Habitual Offender” program to properly address contractors who don't;
- Developing an “811 Ambassador” program to train the PG&E employee to be able to properly identify unsafe excavation activities and take appropriate intervention measures;
- Developing the “Home Owner Association (HOA)” program in hopes to persuade HOAs to adopt requirements that residents call 811 before excavating;
- Utilizing aerial patrolling to identify and intercept threats to the transmission system; and
- Completing the Lean Six-Sigma analysis of PG&E's claims process to ensure recapture of costs associated with third-party dig-ins is one timely and in an effective manner.

III) Locate and Mark

Locate and mark program addresses and help mitigate Risk #10 in Table 3 above. Federal pipeline safety regulations²⁴ and California state law²⁵ require that PG&E belongs to, and shares the costs 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. Information is normally provided by having company personnel visit the work site and place color coded surface markings to show where any pipes and wires are located. Because of its large service territory, PG&E belongs to two regional one call systems which share a common toll free, three digit “811” telephone number. The California one call systems are commonly referred to as USA.

b) Distribution Pipeline Replacement

An important element of providing safe gas distribution service is replacing aging assets. PG&E uses age, materials, seismic factors, and gas leaks to identify and prioritize gas mains for replacement. In addition to gas main replacement, the program covers related service replacement and meter relocation work.

PG&E prioritizes gas distribution pipeline replacement projects based on a risk and reliability determination, which includes the probability of a leak on each section of pipe and the potential consequences of that leak. Each section of pipe is assigned a priority value corresponding with this probability and consequence of a leak. The company maintains a database of gas pipeline replacement pipe and updates the priority values in the Gas Pipeline Replacement Program.

In addition to the Gas Pipeline Replacement Program, which is focused on replacing pre-1940 steel pipe, PG&E has initiated two other replacement programs to improve distribution safety: Copper services replacement, and Aldyl-A distribution pipe replacement. Between 2007, and the end of 2013, PG&E replaced approximately 39,500 copper services through the Copper Services Replacement Program. A number of copper services remain that are being coordinated with street paving moratoriums and pipeline replacement projects.

Certain vintages of Aldyl-A plastic have shown a susceptibility to cracking creating the potential for gas leaks. As a result, PG&E inventoried the gas distribution system to identify the location and vintages of Aldyl-A plastic pipe and initiated a replacement program in 2012. Approximately 25 miles were replaced in 2012, approximately 40 miles were replaced in 2013,

²⁴ 49 CFR §192.614.

²⁵ Code §4216.

with 35 miles planned for replacement in 2014. In total, PG&E is planning to replace approximately 1,500 miles of the approximately 5,535 miles of Aldyl-A pipe over the next 15 to 20 years.

c) Cross-Bore Mitigation

A cross-bore is a gas main or service that has been installed using trenchless technology resulting in the gas pipe being installed unintentionally through a waste-water, or storm-drain system. Cross-bores pose a gas system risk in that they can result in a gas leak into the sewer system during mechanical sewer cleaning operations. PG&E has an inspection program to identify and remediate legacy cross bores. PG&E has overseen the development and implementation of the Cross-bore Safety Inspection Program to minimize the potential risks of legacy Cross Bores. The goal of the Program is to identify cross-bores by completing inspections of potential conflict locations and repairing all occurrences discovered throughout the entire PG&E service territory. This program addresses and helps mitigated Risk #8 in Table 3 above.

The Program takes input from PG&E records indicating where trenchless construction methods were used to install or replace gas services and mains. A Geographic Information System (GIS) is utilized to plan and assign work areas for the closed circuit television video inspection of the interior of sewer pipes to identify where they may be compromised by gas pipes. GIS also enables the tracking of inspection and repair status. Each cross-bore that is identified is tracked from identification to completion. DIMP tracks each cross bore and key information such as location, discovery date, main or service, year of installation, program installation, repair status, and repair date. DIMP also conducts public outreach on cross-bore safety by sending safety brochures on cross-bores to sewer districts, public works agencies, licensed plumbers, plumbers union, and equipment rental stores. In March 2014, DIMP sent out a bill insert to PG&E customers discussing cross-bore and safety message.

In addition, PG&E is implementing a cross-bore prevention program that will make use of pre- and post-video camera inspections to verify no damage occurs to sewer lines when using trenchless installation during construction.

a) Hydrostatic Strength Testing

Hydrostatic strength testing mitigates threats by testing the yield strength of the pipe for the presence of manufacturing defects, such as lack of fusion in a seam weld. PG&E's hydrostatic testing program validates the integrity and assures a margin of safety for its gas transmission pipelines. As part of its Pipeline Safety Enhancement Plan (PSEP),²⁶ PG&E has completed an

²⁶ PG&E filed its PSEP on August 26, 2011, for activities (such as strength testing, pipeline replacement, ILI, and automated valves) from 2011 through the end of 2014.

unprecedented amount of work. As of July 31, 2014, PG&E has validated strength testing (either through records verification or hydrostatic testing) a total of 753 miles of transmission pipeline, which includes 595 miles validated through hydrostatic pressure testing; installed 161 automatic and remote control valves that will automatically shut off gas in an emergency; validated MAOP for all 6,750 miles of its gas transmission pipelines; replaced approximately 89 miles of transmission pipeline; downrated 11.6 miles of transmission pipeline;²⁷ retired 8.7 miles of transmission pipeline;²⁸ and collected and digitized more than 3.7 million pipeline records as we implement an advanced Records and Information Management (RIM) system with next-generation technology and tools.

PG&E selected and prioritized the work using the PSEP decision trees,²⁹ which focused on enhancing the pipeline integrity in segments that had not previously been subjected to a pressure test. The work was prioritized based on location of pipeline segments in HCA, and Class 3 and 4 locations that were operating at a SMYS of 30 percent or greater. This served as a good foundation to manage the potential risk by pipeline segments that had not previously been subjected to pressure testing. PG&E is now moving towards a more holistic approach to prioritizing the management of risk arising from the threats to its Transmission Pipe assets and will be rolling future work into its prioritized work plan such as vintage pipe replacement, valve automation, and ILI retrofitting,³⁰ which will be discussed in the next sections of this Plan.

PG&E will strength test or replace its entire gas transmission pipeline that was not previously tested, in roughly 12-15 years from the start of strength testing in 2011. PG&E is prioritizing its work based on the following priorities listed in order of importance: (i) HCA segments, (ii) Integrity Management Threats; (iii) Class 3 non-HCA segments; (iv) Class 1 and Class 2 non-HCA segments; and (v) short segments.³¹ The hydrostatic testing strength program addresses and helps mitigate Risk #2 in Table 3 above.

²⁷ To downrate a transmission pipeline is to lower its operating pressure to that of distribution pressure (60 pounds per square inch gauge (psig) or less).

²⁸ To retire a pipeline is to remove it from service and not replace it with any other pipe.

²⁹ PSEP decision trees were approved by the Commission in D.12-12-030.

³⁰ As demonstrated in the mitigation plans set forth in Chapters 4A and 4B of PG&E's 2015 GT&S rate case. For further discussion of PG&E's plans for future work see the discussion in Chapter 4A of PG&E's 2015 GT&S rate case.

³¹ See Chapter 4A of PG&E's 2015 GT&S rate case for an in-depth discussion on the hydrostatic testing program.

b) Vintage Pipeline Replacement

A significant portion of PG&E's natural gas pipeline system—approximately 47 percent—was designed, manufactured, constructed, and installed before the start of California pipeline safety laws in 1961. While age alone does not pose a threat to pipeline integrity, age does play a role because of the type of vintage manufacturing and construction practices that were acceptable at that time.³² PG&E considers “vintage pipe” to include pipe manufactured or constructed and fabricated using certain historic practices that are no longer being used today. Historic manufacturing methods include pipe made with flash welds, low frequency Electric Resistance Welded seam, single submerged arc welded seams, or furnace lap welded seams. Historic fabrication and construction methods include pipe that was installed using wrinkle bends, mechanical/compression couplings, miter bends and other non-standard fittings like orange peel reducers, chill ring welds, bell and spigot, or pipe that was constructed with the acetylene girth welding process.

PG&E's Vintage Pipeline Replacement program is primarily focused on removal of historic fabrication and construction methods that are not as readily assessed using ILI or hydrostatic testing. The vintage pipeline replacement program accounts for the fact that in some cases vintage pipe with manufacturing threats are more appropriately managed through replacement, rather than through the hydrostatic testing program. This program addresses and helps mitigate Risk #4 and #9 in Table 3 above.

PG&E has identified approximately 630 miles of transmission pipe, with characteristics that make it more susceptible to certain construction threats. Of those 630 miles, PG&E has further identified approximately 370 miles of vintage pipe where fabrication and construction threats interact with land movement.³³

PG&E follows the ASME B31.8S threat matrix and in its Vintage Pipeline Replacement program targets the threat posed by the presence of these construction defects as they interact with outside forces such as land movement.³⁴

³² This is supported by the report, “The Role of Age in Pipeline Safety,” prepared for the INGAA Foundation, Inc., by John F. Kiefner and Michael J. Rosenfeld, November 8, 2012, Report No 2012.04, which concluded that 85 percent of incidents occurred irrespective of a pipeline's age, with 15 percent related in some way to the age of the pipeline.

³³ Land movement is considered a Weather-Related Outside Force threat. Types of land movement addressed include slow land movement, liquefaction, areas of seismic activity, creep, and other types of land movement.

³⁴ See Chapter 4A of PG&E's 2015 GT&S rate case for an in-depth discussion on the Vintage Pipe Replacement.

c) In-Line Inspection Retrofitting

ILI 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. ILI enables a pipeline operator to learn about the condition of its pipelines and to predict the integrity of those pipelines into the future to address time dependent as well as other threats to pipeline integrity. It involves running technologically advanced inspection tools, often called “smart pigs,” through the inside of the pipeline to collect data about the pipe, and then using that data to identify anomalies that may require further investigation or repair. The ILI program addresses and helps mitigate Risk #1 and #3 in Table 3 above.

PG&E plans to: (1) continue modifying or upgrading the existing pipeline system at an accelerated rate to accommodate an ILI tool; (2) conducting cleaning and inspection “runs” in the pipeline; and (3) conducting Direct Examination and Repair (DE&R) after data analysis is complete. After modifying or upgrading the pipeline system to make the pipelines piggable, inspection runs are generally divided into first-time inspection runs for initial and baseline assessment, and re-inspection runs conducted for re-assessment purposes.

The DE&R remediation effort allows for the preventive repair and mitigation of anomalies before they result in a pipeline leak or rupture. The federal safety regulations (49 CFR §192.933) as well as the integrity management industry standard, “Managing System Integrity of Gas Pipelines (2004)” ASME B31.8S prescribe the actions and schedule of the excavation and repair (or replacement of the pipe) based on the data analysis. Anomalies are characterized as: (1) immediate; (2) scheduled; and (3) monitored. Anomalies categorized as immediate require a temporary pressure reduction and an expedited response.

After a dig is completed, PG&E identifies the cause of the anomalies. This information is used to generate mitigation activities to improve the long-term safety and reliability of the pipeline. A post-assessment of the line is performed to re-evaluate all of the threats identified on the line, establish the next integrity re-assessment date and determine if any identified issues apply to other facilities. A PG&E final report is created for each ILI job which marks the completion of the DE&R.³⁵

d) Corrosion Program

Corrosion is a naturally occurring process that reduces the effectiveness of steel to contain pressurized natural gas. It is a threat that adversely affects the longevity and reliability of natural gas pipelines, valves, pressure vessels, and other pipeline appurtenances such as compressors, metering, and regulator stations. PG&E has identified corrosion as one of the top

³⁵ See Chapter 4A of PG&E’s 2015 GT&S rate case for an in-depth discussion on the ILI program.

threats to PG&E's natural GT&S assets. Starting in 2013, PG&E initiated significant improvements to its Corrosion Control Program and is moving towards the industry best practices of creating a corrosion control "discipline." Elements of such a discipline include concepts such as centralized management with a commitment to corrosion control, employing qualified SMEs, and creating industry standards-based, common approaches to corrosion control on topics such as collection, analysis and integration of accurate and reliable data on which to make risk-based decisions about mitigation efforts.

To better mitigate the threat of external corrosion, PG&E plans to: (1) enhance its cathodic protection system; (2) conduct system-wide close interval surveys; and (3) identify and remediate locations with confirmed electrical interference from Alternating Current or Direct Current. To better mitigate the threat of internal corrosion, PG&E plans to implement site specific plans and enhance gas quality monitoring. To better mitigate the threat of atmospheric corrosion, PG&E plans to enhance its inspection procedure and accelerate the pace at which remediation actions are implemented.

PG&E has developed a prioritized list of work to further evaluate and mitigate previously identified issues within the corrosion program. Changes are being proposed in Chapter 7 of PG&E's 2015 GT&S rate case that will move PG&E towards a more comprehensive and complete corrosion control program that ensures public safety, protects the system, and keeps PG&E in compliance with federal regulations and internal standards. The corrosion program addresses and helps mitigate Risk #1 and #3 in Table 3 above.

e) Earthquake Fault Crossings

PG&E's Fault Crossings program addresses the specific threat of land movement strains at known earthquake faults damaging a pipeline due to seismic events, which also addresses and helps mitigate Risk #5 in Table 3 above. Consistent with California law, which requires natural gas operators to prepare for, and minimize damage to pipelines from earthquakes, PG&E began its fault crossing program in 1985. PG&E conducted several system wide studies which helped shape the direction of PG&E's earthquake fault crossing program.

The detailed studies, which address both the anticipated geologic movement and pipeline mechanical properties, provide critical information to determine how best to manage the integrity of these segments of pipe. Following each study, PG&E implements mitigation measures where necessary to improve the margin of safety at each fault crossing. Mitigation typically includes modified trench designs, trench adjustment, pipe replacement, or installation of automated isolation valves. PG&E describes its proposed programs for earthquake fault crossings in more detail in Chapter 4A of its 2015 GT&S rate case.

f) Leak Survey

Pipeline safety regulations require PG&E to conduct routine leak surveys on its distribution and transmission systems to find gas leaks. The frequency of the leak surveys depend on the type of facility, operating pressure and class location of the pipe. PG&E procedure TD-4110P-01 outlines PG&E's requirements for the leak survey and detection program and summarizes the standards and guidelines for leak survey work. PG&E's current leak survey cycles from TD-4110P-01 are shown in **Table 4** below.

**TABLE 4 – LEAK SURVEY CYCLES
PACIFIC GAS AND ELECTRIC COMPANY**

Leak Survey Frequency	
Facility Types	Survey Frequency
All Company facilities within business districts and at public buildings	Annual
Distribution MAOP less than or equal to 60 psig	
Business district and public buildings	Annual
Buried metallic facilities not under cathodic protections and not covered by an annual requirement	3 years
Balance of underground distribution facilities	5 years
Distribution Feeders (MAOP greater than 60 psig)	
	5 years ³⁶
Transmission	
DOT Transmission All Odorized Transmission with the exception of Non-HCA pipe within a Class 3 and 4 location	Annual
DOT Transmission Non-HCA Class 3 and 4	Semi-Annual
Un-Odorized DOT Transmission	
Class 1 and 2	Annual
Class 3	Semi-Annual
Class 4	Quarterly
Gathering	
Class 1, 2, 3, and 4	Annual
Transmission Stations	
Class 1 and 2	Annual
Class 3 and 4	Semi-Annual
Enclosed Electric Substations and Switching Stations	Every 6 months

g) Leak Repair

All gas leak indications are graded based on a number of factors, including the amount of gas present, the proximity to structures, whether a leak is above or below-ground, and whether a below ground leak is covered wall to wall by concrete or other permanent covering. PG&E personnel classify leaks into four grades based on the severity and location of the leak, the

³⁶ Distribution Feeders that have a MAOP greater than 60 psig are currently on a 5 year leak survey schedule. In its 2015 GT&S rate case, PG&E defined an additional approximately 920 miles of line pipe to be transmission rather than distribution, classifying all distribution feeders over 60 psig transmission. This would move the distribution feeders to an annual leak survey schedule starting in 2015.

hazard the gas leak presents to persons or property, and the likelihood that the leak will become more serious within a specified amount of time.

- Grade 1 leaks (also referred to as “hazardous” leaks) represent existing or probable hazards to persons or property and require immediate repair or continuous action until conditions are no longer hazardous.
- Grade 2+ (Priority Grade 2) leaks fall below Grade 1 criteria and above Grade 2 criteria. These leaks are non-hazardous to persons or property at the time of detection, but still require a scheduled priority repair within 90 days or less.
- Grade 2 leaks are non-hazardous to persons or property at the time of detection, but still require a scheduled repair because they present probable future hazards. Grade 2 leaks must be repaired within 15 months, and rechecked every six months until repaired.
- Grade 3 leaks are non-hazardous at the time of detection and can reasonably be expected to remain non-hazardous. They are re-surveyed and monitored annually, or no later than 15 months, but historically not scheduled for repair (unless leak indications change which qualifies the leak as a Grade 1, Priority Grade 2 or Grade 2 leak).

PG&E’s grading rules exceed industry standards, as set by the ASME Gas Piping Technology Committee Guide for Gas Transmission and Distribution Piping systems, in that PG&E uses a Grade 2+ category with a scheduled priority repair within 90 days.

PG&E has a trained and operator-qualified workforce that finds and repairs leaks using acceptable industry repair methods and procedures. While some leak repair work is completed on above ground facilities, many leak repairs require excavation to below the surface infrastructure facilities. All work performed is documented for completeness.

PG&E is now responding to leaks faster than ever before – and surpassing industry averages. As of July 2014, PG&E’s average response rate to calls from customers reporting gas odors was under 20 minutes, and industry benchmarking shows that PG&E has moved from the bottom quartile to one of the top responders in the country.

h) Pipeline Patrol and Monitoring

Pipeline Patrol and Monitoring involves Operator-Qualified personnel visually inspecting transmission pipelines, and select distribution facilities. Patrolling is conducted either aerially or on the ground to provide continuing surveillance of abnormal operating conditions and potential threats to pipeline integrity on or near the pipeline. Patrolling includes, but is not limited to, monitoring excavations near pipelines, and reporting vegetative and structural encroachments

that may impede transmission pipeline access. Exceeding federal requirements,³⁷ PG&E's Pipeline Patrol Program seeks to conduct patrols on a monthly basis.³⁸ PG&E also performs patrols of pipelines located in High-Consequence Areas twice each month, as well as special patrols following natural disasters or other incidents as necessary.

PG&E revised its patrol work procedure in August 2012, in response to the Root Cause Recommendations made by the then-CPSD as part of the Class Location Order Instituting Investigation (I.11-11-009). In adherence to the revised procedure, all personnel who continued or began patrolling underwent new, mandatory training and were required to hold additional Operator Qualifications (OQ), one of which was revised for the new program. Additional program improvements were implemented during 2013, which included the institution of a dedicated aerial observer (to accompany the pilot), the utilization of mobile tablet technology for recording aerial observations, the review of video captured during aerial patrol flights as a Quality Control (QC) measure, the creation of a catalog for persistently-reported encroachments, and a streamlining of the aerial observation follow-up process. These enhancements prompted another revision of the patrol work procedure, which took effect on January 1, 2014. Ground patrollers were retrained and re-qualified by June 30, 2014, in order for them to continue patrolling. Forthcoming improvements include the incorporation of improved pipeline location data from the Pipeline Centerline Survey (see discussion below), as well as the comparison of persistently-reported encroachments with Land Management's data as a Quality Assurance (QA) and control measure.

I) Pipeline Markers

49 CFR §192.707 requires PG&E to provide line markers and warning information for select gas pipelines. Pipeline markers and indicators³⁹ are used to indicate the approximate location of the respective pipeline along its route, which contributes to public awareness and damage prevention. The markers are signs on the surface above or near the natural gas pipelines located at frequent intervals along the pipeline right-of-way. The markers can typically be found

³⁷ Per 49 C.F.R. §192.705, Class 1 and 2 transmission pipelines must be patrolled at least annually; Class 3 transmission pipelines must be patrolled at least two times per year; Class 4 transmission pipelines must be patrolled at least quarterly. Per 49 C.F.R. §192.721, patrols of distribution pipelines "in places or on structures where anticipated physical movement or external loading could cause failure or leakage" are required at least quarterly for such pipelines in business districts, and at least twice per year for such pipelines outside of business districts.

³⁸ PG&E has committed to patrol select pipelines more often than required by federal code.

³⁹ Pipeline indicators are PG&E's term for objects that inform about the location of the pipeline but do not meet the federal code's text lettering and spacing requirements (e.g., one inch high, with ¼-inch stroke) to be formally considered markers.

at various points along the pipeline route including highway, railway, and waterway intersections. These markers display the name of the operator and a telephone number where the operator can be reached in the event of an emergency.

PG&E's Procedure "*Gas Pipeline Markers and Indicators*" outlines PG&E's process for installing and maintaining pipeline markers in compliance with state and federal requirements. A revision to this procedure was published on September 18, 2013, to account for program improvements including the addition of a more durable and visible Tri-View™ marker, the implementation of additional pipeline indicators to further identify the presence of a pipeline in locations where markers may be impractical, and the implementation of pipeline marker and indicator installation forms to allow installation data to be recorded and absorbed into the system of record. As part of the Pipeline Centerline Survey (discussed in next section), approximately 12,000 pipeline markers were installed from July 2013 to March 2014.

II) Pipeline Pathways

Pipeline Pathways is a multiyear program that is designed to enhance safety by reducing risk to the integrity of the transmission pipelines, and improving access to PG&E rights-of-way. In 2014, PG&E's main effort is focused on identifying and removing structures and non-compatible vegetation above and around the pipelines that represent potential risks to safety. PG&E implements the Pipeline Pathways program through various projects, which are listed below:

- **Pipeline Centerline Survey** – This project included surveying 6,750 miles of gas transmission pipeline by using precise mapping tools with Global Positioning System (GPS) coordinates, and entering the GPS coordinates into a new GIS. This project was completed in December 2013 and allows PG&E to accurately locate and monitor its gas transmission pipelines.
- **Encroachment Clearance** – This project includes locating, staking, and mapping the center of the pipeline, and checking the area above the pipeline for any structures or vegetation that could interfere with PG&E's ability to maintain, inspect, and safely operate the pipeline. This is followed by remediation of any such encroachments deemed unacceptable for the safe maintenance and operation of the pipeline. The main focus in 2014, is removing structures and trees from PG&E rights-of-way. PG&E is working with home owners and cities on these efforts to identify the best solutions.

- **Vegetation Management** – This project is focused on keeping PG&E’s right-of-way open and free of “non-compatible vegetation.” Along with structure clearing, this improves our ability to respond in emergency situations
- **Pipeline Marker Installation** – PG&E is increasing the number of pipeline markers on transmission pipelines to enhance public awareness and damage prevention while increasing safety activities around pipelines by providing a clear line of sight. This project was completed in March 2014. PG&E is continually monitoring and maintaining its pipeline markers.

The efforts under the Pipeline Pathways program strengthen PG&E’s ongoing pipeline safety programs, improve the ability to identify and prevent risks to our pipelines, and give PG&E better access to inspect, test, and maintain pipelines.

i) Cyber Security

To address the threat from cyber security (Risk #6 in Table 3 above), PG&E must proactively invest in ensuring effective controls in order to reduce risk and maintain the resiliency of our critical infrastructure. PG&E must endeavor to prevent when possible—and adapt to, withstand, and rapidly recover from when necessary—risks such as:

- Intrusions (physical or cyber)
- Attacks (physical or cyber)
- Disasters (natural or man-made)
- Accidents (natural or man-made)
- Changing conditions and other incidents

PG&E has a Gas Cyber Security Program that will strengthen its Gas Operations Transmission Data Network, through the development of various tools, procedures, and programs that are described below as part of Gas System Operations and Control. This project is being coordinated with other Cyber Security programs and projects that are being developed in PG&E.⁴⁰

b. Mitigating Loss of Supply

a) System Pressure and Capacity

PG&E designs and operates its gas system to ensure safe pressure regulation and adequate gas supplies. A focused plan for pressure regulation includes extensive data

⁴⁰ See PG&E’s 2015 GT&S rate case testimony Chapter 11 for an in-depth discussion on PG&E’s cyber security programs.

gathering, root cause analysis of any over pressure event, and a corrective action and improvement plan that includes evaluating equipment set points and Supervisory Control and Data Acquisition (SCADA) alarm points.

PG&E's pipeline capacity is sized to provide all core⁴¹ customers with uninterrupted service on a one-day-in-90-year cold temperature design day (referred to as an Abnormal Peak Day), and to provide all customers, including noncore,⁴² with uninterrupted service on a one-day-in-two-year design day (referred to as a Cold Winter Day). Abnormal Peak Day and Cold Winter Days are based on conditions that have actually occurred on PG&E's system within those respective time spans.

Customers value service reliability and there can be significant public health and safety risks associated with insufficient capacity. A lack of pipeline capacity could lead to a loss of gas service that customers depend on for daily life activities including space heating, water heating, and cooking. In very cold weather, loss of space heating can itself be life-threatening, and can prompt customers to use unsafe heating alternatives such as outdoor grills and barbecues. Loss of gas service can also lead to extinguished pilots and the subsequent potential for uncombusted gas entering affected buildings. In some scenarios, loss of gas service can affect electric generation, which during very hot weather can also result in safety concerns.

PG&E's pipeline capacity planning requirements are outlined in Standard "*Gas Transmission and Distribution Systems Capacity Planning Requirements*." The standard is supported by a companion document, "*Gas Transmission and Distribution Systems Capacity Planning Procedures*." Under the framework provided in these procedures, PG&E routinely and systematically studies its storage, transmission, and distribution systems, to ensure capacity is adequate to meet design day criteria. PG&E's Gas System Planning Department obtains information from a variety of sources, including operational data, other PG&E departments, government agencies, planning commissions, regulatory proceedings, and news reports to determine possible load growth and other potential changes that may affect system capacity requirements. In addition, systems are studied as needed to ensure that planned pipeline operations such as ILI, pressure-testing, maintenance, and repair are managed for minimum impact on capacity.

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

⁴¹ Core Customers include residential and small commercial.

⁴² Non-Core Customers include large commercial, industrial or institutional.

In 2013, Gas System Planning launched its Network Investment Plan program.⁴³ Under this multi-year program, Gas System Planning will analyze PG&E's many gas systems in a long-term, holistic manner to optimize system design. The objective is to ensure that the various safety-related pipeline efforts including pipe replacement, ILIs, hydrotests, valve automation, and station work are incorporated efficiently into design work driven by other factors such as future growth over a ten to twenty-year time horizon. This long-term planning effort is also intended to wring out any existing design inefficiencies such as multiple short-run diameter changes that inhibit pigability and potential safety risks such as excessive manual winter operations and operating with little margin of safety against overpressure events. PG&E has completed eight investment plans, 4 are near complete, 2 are in progress, and 12 more will be started later in 2014.

b) Overpressure Elimination Initiative

Pressure is a significant driver of pipeline capacity, so it is necessary to conduct hydraulic studies on each system to ensure that design day criteria can be met at the proposed regulator set point. In 2012, PG&E began an initiative to eliminate unintentional system overpressure events above MAOP. This program has focused on establishing an even greater operating margin between system normal operating pressure and system MAOP, putting standards and procedures in place to eliminate operating errors and looking for and resolving recurring equipment issues that can lead to system overpressure events. The results of the program have reduced overpressure events on the system from 774 in 2011 to a total of 31 in 2013. Only 11 overpressure events have occurred year-to-date (end of July 2014), compared to an annual goal of 24 or fewer events. In 2014 and 2015, the program focus will be improvements in clearance development and adherence, improvements in procedures on manual operations and further work on equipment performance improvement.

Similarly, PG&E has evaluated and reduced pressures in its gas distribution systems where possible to provide increased separation between pressure control set points and maximum operating pressures.

c) Operations Clearance Procedures

An important part of public safety is ensuring that the company uses a clearance procedure for gas operations. Clearance procedures are an added safety step to confirm that a plan and procedure is in place before work is performed. The Transmission Clearance Procedure is used for work that impacts gas flows, pressures, or gas quality. If a transmission facility is to be taken

⁴³ See Chapter 10 of PG&E's 2015 GT&S rate case for an in-depth discussion on the Network Investment Plans.

out of service for repairs, a plan and procedure (“clearance”) must be formalized in writing and reviewed by the field and engineering personnel scheduled to perform the work. Transmission system clearances are managed and approved by Gas Transmission Control.

For distribution, PG&E is in the process of developing the Distribution Clearance Procedure which will help eliminate work performance errors, unplanned outages, and at-fault dig-in events through a centralized review of pending work. In essence, all work associated with gas distribution facilities will require approval and/or situational awareness from the Distribution Control Center for activities impacting the gas network. Field personnel will call the control room to report a clearance and technology will be used for situational awareness of employees performing non-clearance activity.

Industry best practices are being adopted for both the Distribution Clearance Procedure and the Transmission Clearance Procedure. PG&E has developed an electronic tool to administer its clearance procedures for both Transmission and Distribution. The Transmission electronic tool was phased in during 2014. The Distribution electronic tool completed its pilot phase and will be on a roll-out schedule through 2015. Both electronic tools have been designed to insure the clearance process is executed in a thorough, consistent, and visible manner.

d) Supplier Quality for Distribution and Transmission Gas Products

Supplier QA establishes procedures, practices, and expectations, pertaining to the quality of transmission and distribution products purchased by PG&E. The requirements set forth assure consistent quality based on processes for supplier approval, product approval, receiving inspection, supplier audits, product nonconformance resolution, and supply base scorecards for key suppliers.

The programs that comprise the overall quality system are varied, inter-related and generally involve engagement activity from materials personnel, field personnel, standards engineering, purchasing personnel as well as quality engineers and inspectors.

Distribution Gas Products

For the distribution system, PG&E maintains a database of all products that have been identified by standards engineering as safety significant. These products have inspection plans that are routinely reviewed for updates based on revisions to the associated engineering standards. All products that require inspection are inspected according to the documented inspection plan. No nonconforming product is allowed into stock.

If a product fails at receiving inspection or in the field and that failure appears to be part of a trend or may be repetitive, PG&E Supplier Quality Engineers work directly with the manufacturer

to resolve the issue through root cause analysis and corrective action plans. The non-conformance issues are identified and documented in the Material Problem Reporting system. Supplier QA manages the Material Problem Reporting system which is available to all personnel at PG&E to allow employees to document any defective or suspect defective material including tools and gas carrying products (material problem reporting is discussed in Section III.B.3).

If it is determined the nonconformance issue may be related to the supplier, then a Supplier Corrective Action Request is issued requiring product containment and a corrective action plan. A Supplier Quality Engineer will determine if the supplier's response and corrective actions are adequate. All key suppliers have their quality performance measured on a continuous basis. The measurement process is an industry recognized system called Defective Parts Per Million (DPPM). All new suppliers, production products, and tooling must first be approved by a team review of their quality processes per PG&E's standards.

Transmission Gas Products

The Supplier QA procedures and systems for procured transmission products is the same as for distribution products except in the area of inspections. Transmission products do not pass through a PG&E receiving location and therefore a receiving inspection is not performed. Instead, all transmission products undergo source inspection at the supplier's site. Due to the difference in the inspection location, a DPPM score is not produced because is not accessible from the inspection site.

c. Mitigating Inadequate Response and Recovery

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 ICS, 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.

The next sections discuss programs in place to mitigate threats that have the potential to prevent PG&E to respond in a timely manner.

a) Gas System Operations and Control

PG&E's Transmission and Distribution Gas Control Centers monitor and control the flow of gas across our system 24 hours a day, 365 days per year, to ensure that it is received and delivered safely and reliably to customers. PG&E utilizes an operational manual that contains the necessary documents for control room personnel to manage and operate the gas transmission and distribution systems, in accordance with the requirements outlined under 49 CFR 192.631, Control Room Management (CRM). PG&E's CRM manual contains the standard, procedures, plans, and processes that collectively address how the gas control room personnel conduct their work activity under normal, abnormal, and emergency operating conditions. The CRM manual has six over-arching procedures: (1) Information Management; (2) Fatigue Mitigation; (3) Alarm Management; (4) Management of Pipeline Changes; (5) Evaluating Operational Experience; and (6) Gas Control Training Program.

PG&E has also completed development of a software application to create a bridge between the SCADA alarm system and the OSIsoft PI Historian to improve situational awareness and provide greater capability to track and analyze alarm information.⁴⁴ Billions of data records have been loaded into the OSIsoft PI Data Historian system representing more than a decade of historic SCADA information. New data is being added to the OSIsoft PI Data Historian system continuously, within seconds of being recorded in the SCADA system.

This platform is being utilized to rapidly provide near real-time information to Gas Control and planning areas of the Gas Operations organization with plans to expand its use to engineering and maintenance areas. This will provide better guidance and input for remote

⁴⁴ In late December 2011, PG&E completed a SCADA enhancement that prioritizes alarms for appropriate operator action upon activation. This SCADA modification project provides PG&E's operating team the capability to filter alarms based on priority, data type, and geographic location. Alarm priorities can now be configured based on four categories: Emergency, High, Medium, and Low.

monitoring and controls, as well as for real-time operations. PG&E is using the real-time OSIsoft PI Data Historian platform to support creation of various situational awareness screens.

I) Transmission Control Center

The Transmission Gas Control Center monitors and controls system pressure, flow and operation status utilizing approximately 10,000 SCADA points, providing oversight of all compressor stations, storage fields, pipeline interconnections, and other key pipeline facilities. Gas Transmission Control operators can control system flows and pressures utilizing approximately 800 supervisory control points. In addition, the SCADA system continually provides calculated data for approximately 3,000 other points representing system inventory, supply and demand information on the transmission system.

The SCADA system utilizes alarms to warn Gas Transmission Control of changing conditions that could escalate to abnormal or emergency conditions and provides prioritization functionality. The system provides alarm filtering based on priority, data type, and geographic location to facilitate appropriate operator action upon alarm activation. Alarm priorities are configured based on four categories: Emergency, High, Medium, and Low. PG&E also has a geographical based operating process which allows for assignment of operator responsibilities based on “north” and “south” service territory assignments.

II) Distribution Control Center

PG&E’s gas distribution system covers an area of 58,000 square miles, with 826 hydraulically independent systems. Real-time distribution oversight is provided by Gas Distribution Control at approximately 292 continuously monitored distribution locations at district regulator stations and pipelines. In addition, some local distribution oversight is enabled by approximately 350 electronic recording devices which alert local on-call distribution supervisors if pressure set points are exceeded. Should an electronic recording activate, the local distribution supervisor is responsible for assessing the nature of the alert and, if appropriate, dispatching PG&E personnel to address the situation. To monitor the balance of the distribution system, local offices collectively deploy more than 500 permanent and temporary chart recorders⁴⁵ to record pressure data.

PG&E installed 417 monitoring and control devices across the gas distribution service area in 2013 and plans to install approximately 3,500 devices from 2014 through 2020, for a total of

⁴⁵ A chart recorder uses paper charts to record system pressures over time; typically 30 days. These are then used by engineering personnel to analyze historic usage and to forecast future capacity needs.

3,900 devices. Over time, the number of field monitoring locations will provide over 95 percent visibility of the distribution network.

b) Enhancements to Transmission and Distribution Control Centers

In the 3rd quarter of 2013, PG&E opened a new state-of-the-art gas control facility to monitor and manage its entire gas system. The new facility co-located Gas Transmission Control Center, Gas Distribution Control Center and Gas Dispatch functions into a single facility operating 24-hours a day. The co-location of these three functions enables the company to increase system knowledge and situational awareness to provide superior emergency response coordination and facilitates better communication, information sharing and monitoring.

The control centers have sufficient physical infrastructure redundancy such that no single point of infrastructure failure will affect operations. Key features of the facility design include:

- Backup power supplied by a second service line to provide two independent paths for power to critical systems
- Standby power supplied by two diesel generators outside of the facility
- Two uninterruptible power systems to provide protection from electrical faults
- An independent Heating, Ventilation and Air Conditioning (HVAC) system for the control room, with the building's HVAC serving as backup

c) Valve Automation

PG&E's Valve Automation Program is designed to enhance emergency response in the event of a gas transmission pipeline rupture. This program builds upon the scope, principles and decision trees that the Commission approved in D.12-12-030 as part of PG&E's PSEP. In D.12-12-030, the Commission approved the plan to replace, automate, and upgrade 228 gas shut-off valves from 2011-2014. The valve automation plan is subject to permitting and weather clearances, which will defer some valve automation projects to 2015.

This automation program will result in approximately 504 miles of additional gas transmission pipeline that can rapidly be isolated through remote control valve technology. Installation of automated isolation capability on major pipelines in heavily populated areas increases emergency preparedness, and may reduce property damage and the danger to emergency personnel and the public in the event of a pipeline rupture.⁴⁶

⁴⁶ See Chapter 4A of PG&E's 2015 GT&S rate case for an in-depth discussion on the Valve Automation.

d) Emergency Response

l) Company Emergency Plan

PG&E's Company Emergency Plan (CEP) (**Attachment 11**) provides a broad outline of PG&E's organizational structure and describes the activities which will be undertaken in response to emergency situations. The CEP will be used during emergencies by presenting a response structure with clear roles and responsibilities and identifying coordination efforts with outside organizations (government, media, other electric and gas utilities, essential community services, vendors, contractors).

Details of how PG&E accomplishes the functions described in the CEP are found in topic-specific plans prepared by the individual departments and LOB. PG&E maintains over 18 Emergency Operation Plans (EOP) for the various organizations, including the Gas Emergency Response Plan (GERP) (Section VII.B.1 of the CEP), which provides detailed information about PG&E's planned response to gas transmission and distribution emergencies. These individual EOPs are updated annually. In addition to the EOPs, PG&E maintains approximately 48 Business Continuity Plans, which describe how PG&E will continue essential business operations in the event of a disruption to facilities, technology or personnel.

PG&E also utilizes the ICS, which is a systemic tool used for the command, control, and coordination of emergency response. The ICS provides a systematic, proactive approach for all levels of governmental and nongovernmental 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. It also gives a clear understanding of managing an incident with the use of an Incident Action Plan. The Incident Action Plan focuses on clarifying the situation, establishing incident objectives and strategy, developing a plan, preparing and disseminating the plan, executing the plan, and evaluating and revising the plan, and finally demobilization.

A) Response to Emergency Events

To ensure a consistent and well-coordinated response to emergencies, the company has developed the following emergency classification system known as PG&E Incident Levels:

- **Level 1 – Routine:** These incidents involve a relatively small number of customers, such as those managed during routine operations. Local resources are sufficient to respond. This level does not require the activation of an emergency center.
- **Level 2 – Elevated:** This is a pending potential incident or a local emergency that requires more than a routine operations response. Resources are mainly local, but there is a possibility that resources may need to move within the region.

Emergency Center activation includes: Operations Emergency Center (OEC) Communications Only, OEC activation is possible.

- **Level 3 – Serious:** This serious incident involves large numbers of customers. Resources mainly move within the region, but may need to move between regions. Emergency Center activation: OEC activation, Regional Emergency Center (REC) and Emergency Operations Center (EOC) activation possible.
- **Level 4 – Severe:** This is an escalating incident with company impact/extended multiple emergency incidents that impact a large number of customers. Resources move between regions, general contractors are utilized, and mutual aid may be needed. Emergency Center activation: OEC, REC and EOC are activated. Incident Support Team (IST)⁴⁷ activation is possible.
- **Level 5 – Catastrophic:** This is a catastrophic event that includes multiple emergency incidents, impacts a large number of customers, has a significant cost, and significant infrastructure risk/damage. This level of emergency affects the company and its ability to conduct business operations. The full mobilization of company resources is needed to respond, and mutual aid resources are needed. Emergency Center activation: OEC, REC, EOC, IST activated.

The OEC and REC are emergency centers that manage the work in a defined geographic region, and are responsible for directing resources to implement actions and for reporting status and progress through the Emergency Center chain of command, ultimately to the EOC. The EOC is a designated location at which key personnel meet to coordinate or command response to an emergency. The EOC is equipped with all necessary equipment, supplies, information and data systems, backup power, and other resources needed to conduct prompt and effective emergency response activities. The EOC has a designated backup facility in the event that the primary EOC is not available or accessible.

PG&E's Incident Levels help 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 needed, etc.).⁴⁸

⁴⁷ The mission of the IST is to support the execution of the incident response. The IST membership is made up of the LOB senior operating executives who maintain a comprehensive view of the response and affirm that the EOC Commander's restoration priorities and incident objectives are being effectively carried out. The IST further supports the EOC Commander by making policy decisions and removing roadblocks that may affect restoration and recovery. The IST is activated by the VP of EP&R and may convene via conference call or in person.

⁴⁸ See Attachment 11 for more discussion of the CEP.

II) Gas Emergency Preparedness and Response

The Emergency Preparedness and Public Awareness (EP&PA) Department in Gas Operations supports coordination activities, training, and communication with city/county/local first responders within PG&E's service territory. A primary function of the EP&PA department is to provide pipeline and general safety training to local/state/volunteer first responders, as well as share the GERP with the appropriate community partners. The EP&PA department is actively engaged in incident response, all facets of emergency preparedness planning, training (for both internal and external responders), performance measurement, and regulatory compliance. Responsibilities of this department include maintenance of the GERP to assist PG&E personnel in responding safely, efficiently, and in a coordinated manner to emergencies affecting gas transmission and distribution systems. Additionally, the EP&PA department coordinates After Action Reviews of gas incidents and exercises, holds program responsibility for Gas Operations Business Continuity Plans, designs and facilitates functional/field and tabletop exercises and drills, and participates in industry benchmarking on Emergency Management solutions and best practices.

An example of a drill PG&E conducts is its annual company-wide emergency drill, which was held on May 14 and 15, 2014. The exercise, called the Hayward Fault scenario, was a 7.0 magnitude earthquake, on the Hayward Fault, centered in San Pablo Bay. The scenario spanned twelve-hours over two days and was designed to test several newly written emergency response plans, including communication capabilities, conduct damage assessment, use damage modeling to identify resources needed for restoration, ability to integrated a gas and electric response, and set up a base camp to effectively move crews throughout the simulated damaged area. Core capabilities that were used to achieve objectives were: Planning, Situation Awareness, Operational Communications, Public and Private Services and Resources, and Operational Coordination. Participants in this two-day event included local and state regulators, emergency responder teams, other public agencies, and PG&E.

The GERP (**Attachment 12**) describes the roles and responsibilities of PG&E's emergency response personnel, which include a single person who assumes command and designates specific duties for the SCADA staff and all other potentially involved company employees.

PG&E's 911 Notification Process requires PG&E's control room operators to make the 911 notification immediately based on the following SCADA alarm conditions:

- Relief **valve open alarm** venting gas to atmosphere;
- Automatic shut off **valve closed alarm** indicating isolation of a section of pipeline;
- Activation of a **pressure drop – rate high alarm** indicating a high differential across one of the newly installed remote control isolation valves; and

- Activation of a **Lo-Lo pressure alarm** indicating possible pipeline rupture (confirmed valid by verification of upstream and downstream pressure sites and correlated supply source metered flow increase).

Once SCADA alarm conditions have been triggered, and/or non-SCADA based information has been received suggesting an emergency operating condition, PG&E follows a detailed procedure that explicitly requires Gas Control to notify 911 Emergency Response Centers. The PG&E 911 Notification Process includes triggers to immediately make 911 notifications concerning a transmission or distribution facility involvement in a natural gas related event.

In order to improve focus on real time monitoring, PG&E has implemented geographical based responsibilities for gas system operators. Transmission control operators are assigned to monitoring north or south portion of the system. For distribution control, the assignments are broken out by Northern, Bay, Central Coast, and Central Valley. At any given time, operators are now responsible for monitoring their assigned areas only (see control room discussion in Section II.B.4.b.b.).

Additionally, PG&E has a fleet of new Mobile Command Vehicles to respond more rapidly to natural gas or electric emergencies. PG&E has six Mobile Command Vehicles and four Emergency Communication Trailers, which are used with the Mobile Command Vehicles to boost the radio signals.

III) Earthquake Response

PG&E uses GIS based products to enhance emergency response following a significant earthquake. PG&E's Gas Transmission Earthquake Plan and Response Procedure is provided in Risk Management Instruction (RMI) – 04 (**Attachment 13**) and the Gas Distribution Earthquake Plan is provided in RMI- 04B (**Attachment 14**). These plans describe PG&E's use of United States Geological Survey data and identify service areas that are potentially impacted. The susceptibility to seismic activity and geotechnical conditions is reviewed annually, and updated to provide accurate response areas over PG&E's Service Territory.

The GERP provides guidance and information for responding to earthquake emergencies (Appendix A.2. Training Aid 7 – Earthquake, see Attachment 13). PG&E has also updated the *Earthquake Playbook* (EMER-1012M) (**Attachment 15**), to provide guidance on PG&E's response and recovery actions. The *Earthquake Playbook* provides an executive-level perspective on disaster conditions the company will face immediately after an earthquake, including actions it will take and how it will conduct business

IV) Information for First Responders and the Public

PG&E launched a web portal within pge.com dedicated to external first responders and residential customers. Access to training materials, general mapping of gas transmission pipeline segment locations, safety DVDs, and literature on school safety is available, along with other information and resources for gas emergency response. Enhancements have been made to some of the data available to first responders so that they can use it in real time while en-route to an incident or once they have arrived on scene. For example, registered first responders now have access to more detailed characteristics of gas transmission assets, portions of the GERP, and contact information to key members of the EP&PA department.

PG&E has developed specific informational flyers and has issued press releases to promote safety (such as for dig-ins which potentially damage infrastructure and for customer behavior around potentially dangerous infrastructure including downed power lines). These materials are accessible through pge.com and a special safety education website at www.pge.com/safetycentral.

V) Call Center

PG&E operates a 24/7 Contact Center to receive calls from customers and emergency responders. All Contact Center representatives receive an annual training on gas emergency response procedures. Related call handling processes are housed in an online repository that is utilized by Contact Center representatives to ensure adherence to public safety and emergency procedures during any event of a gas emergency, pipeline integrity situation or threat to public safety. The Gas Dispatch Center is notified immediately of any emergency gas situation that is called into the Contact Center.

VI) Response to Customer Odor Calls

PG&E's response to customer calls to gas odors was in the top decile performance of benchmarked utilities last year. PG&E has responded to 99.6 percent of all gas emergency response calls within 60 minutes and on average responded in 20.0 minutes year-to-date 2014.

C. Compliance

1. Codes, Standards, Policies, and Procedures

PG&E has numerous standards, policies, and procedures in place to support Gas Operations, and to ensure work performed by employees and contractors is done safely and consistently. PG&E's gas standards, including Operations and Maintenance procedures, are developed to comply with federal and state pipeline safety regulations. The Regulatory Compliance organization monitors and tracks changes to legislation and regulatory

requirements to ensure timely implementation. The Standards and Procedures organization is responsible for documenting changes so that policies, standards, procedures, practices, and training materials are updated, in a timely fashion to meet federal and state requirements.

PG&E follows its gas guidance document development and update process to publish its documents. Published documents have assigned SMEs that perform assessments of guidance documents to determine the need for developing or altering the document. PG&E's gas guidance documents are defined as follows:

- **Policy:** Provides high-level, broad instruction about a significant business operation, subject or function, consistent with laws and regulations, the company's vision, values, and goals, and any direction from the Boards of Directors.
- **Standard:** Describes the major steps of a work process and/or major internal or external compliance requirements, and the roles and responsibilities of those involved. A standard may involve one or more organizations, departments, job functions, or compliance requirements. A standard can be a stand-alone document or incorporated in a manual with implementing procedures and other related information, e.g., forms, drawings, or specifications.
- **Procedure:** Detailed, step-by-step instruction that describes the functions, tasks, and expectations of employees who are responsible for performing a specific function or task. A procedure includes or refers to all safety, health, and environmental instructions that an employee needs to perform the work correctly. A procedure can be a stand-alone document or incorporated in a manual with governing standards and other related information, e.g., forms, drawings, or specifications.
- **Bulletin:** A brief, interim, and temporary guidance document designed to heighten awareness of a particular issue, usually one or more of the following: an immediate change in how business is done and/or information about a safety, health or environmental incident or issue and resulting required actions, and/or information about a new mandatory compliance requirement, and/or a clarification of a previous instruction ("how-to" instruction often is included). As soon as practicable, the document owner incorporates the bulletin information into the parent policy, standard, or procedure and cancels the bulletin.

PG&E also has gas technical teams comprised of cross-functional representatives that assure the standards, procedures, tools, and technologies used in specific areas remain current and updated. The technical teams are made up of a cross section of employees representing

technical SMEs, field representatives who perform the work, training experts, those responsible for evaluating employee qualifications, and those who perform related engineering, design and records activities. Major duties of the technical teams include:

- Identifying issues and resolutions
- Identifying documents
- Writing and/or revising guidance documents
- Approving documents
- Approving products
- Identifying training
- Evaluating best practices or processes used by other utilities.

To ensure the standards, procedures, tools, and technologies are current, PG&E maintains gas technical teams as shown in **Attachment 16**. Gas technical teams provide support, recommendations, evaluations, and user feedback on the performance, operation, maintenance, development, and implementation.

Work quality field assessments are conducted using published work procedure documents to ensure the document is being followed and to identify further areas of opportunity. Findings and identified deficiencies in the documents are provided to the appropriate technical team for evaluation and revisions.

Published documents currently in effect are posted to PG&E's Technical Information Library to allow for broad access by employees. Based on employee feedback a 24/7 helpline was created to support employees in finding documents and in obtaining technical clarification to standards and procedures. The helpline is staffed by engineers who are responsible for the standards document content.

a. Code Compliance

The State of California's rules governing the design, construction, testing, operation, and maintenance of gas transmission and distribution pipeline systems are specified in Commission's General Order (GO) 112-E. The Commission has incorporated 49 CFR, Parts 190, 191, 192, 193, and 199, which govern the design, construction, testing, operation, and maintenance of Gas Piping Systems into its GO 112-E.

PG&E has developed and implemented policies, procedures and programs that govern the design, construction, installation, operation, maintenance and determination of MAOP for gas transmission and distribution facilities in accordance with GO 112-E. These policies, procedures and programs are updated in a timely manner as appropriate in response to changes in regulation, safety advisories, and other safety information.

To meet compliance with CPUC rulings, PG&E submits recurring compliance reports regularly to the CPUC. A listing of these reports is shown in **Attachment 17**. In addition, ALJ-274 requires natural gas pipeline operators to self-report non-compliances to the CPUC within 10 days of discovery, and to implement corrective actions to remedy the issues. As part of this process, PG&E reaches out to employees at all levels of the organization encouraging them to help identify issues, gaps and non-compliance items. To date, numerous items have been raised and self-reported to the CPUC and in doing so allows PG&E to identify and make systemwide improvements.

As a result of ongoing communications to all employees about the need to report, and the positive recognition of employees who raise issues, PG&E has submitted 10 self-reports as of June 30, 2014.

Parts (a) through (g) in this section discuss some the code sections PG&E must comply with.

a) Maximum Allowable Operating Pressure

A MAOP is established for each pipeline or piping system. The established MAOP cannot exceed the maximum pressure allowed by regulatory code as specified in 49 CFR §192.105, 49 CFR §192.611 and 49 CFR §192.619 through 49 CFR §192.623, as applicable. Class location, design, testing, and operating history are all factors that can limit the MAOP of a pipeline or system.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 became Public Law 112-90 on January 3, 2012. This law, in part, requires gas transmission operators to verify that records accurately reflect the physical and operational characteristics of transmission pipeline in Class 3 and Class 4 locations and Class 1 and Class 2 high-consequence areas and then confirm the established MAOP.

b) Class Location

The Class Location Program is a compliance requirement to ensure that pipelines are operating within the appropriate class as determined by population density. 49 CFR Part 192.613 requires that each operator have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location.

Currently, a majority of the class location changes are identified through the annual class location study. This study includes orthographically corrected aerial photography, occupancy field verification, creation of a digitized structures layer, and annual class analysis completed via a qualified third party firm and that is verified internally. Additionally, changes in class are discovered through routine pipeline patrols performed by way of fixed wing aircraft, helicopters,

and by pipeline patrol employees on foot. Input may also be provided by other field personnel during routine preventive maintenance activities along the transmission pipeline system.

PG&E's Class Location Program is a critical component of PG&E's gas transmission asset management program. PG&E is continually improving processes and technology to accurately identify and map the effects of new construction in order to find and mitigate class location changes. Mitigation is achieved by strength testing, pipeline replacement or reducing pressure.⁴⁹

Also new in 2014 is the application of automated software to analyze Class Locations, which will minimize the possibility of human error in the manual analysis, and will provide the capability to determine Class Location changes on an on-going basis, as new structures are identified.

Consistent with 49 CFR, Part 192.611, if a pipeline class change-up is identified, the MAOP of the pipeline is reviewed and action is taken to assure the pipeline is commensurate with the new Class Location. If a segment of pipeline is determined to be non-commensurate with the new class, but no immediate hazard exists, PG&E will remediate the pipeline by hydro testing, replacement, or retirement as described in PG&E's Gas Design Standards. Confirmation or revision of the MAOP that is required as a result of the study must be completed within 24 months of the change in class location.

When a class change-up is identified on transmission pipe operating above 40 percent SMYS, 49 CFR, Part 192.609 requires that PG&E immediately initiate a study on the pipeline segments involved.

c) Design

49 CFR Part 192 Subparts B, C, and D specify the minimum requirements for the material selection and design of pipe and pipeline components. PG&E's transmission and distribution pipelines and facilities are designed with approved materials that have sufficient wall thickness and/or adequate protection to withstand anticipated external pressures and loads. The pipe and facilities are also designed with materials of sufficient strength to contain internal pressures plus appropriate design and/or safety factors. Components, including valves, flanges, and fittings meet the minimum prescribed requirements specified in the regulations. The design also includes pressure relief or other protective devices to prevent accidental over-pressurization. To emphasize professional engineering reviews and focus accountability, all pipeline plan and profile/section drawings for work on pipelines with a design pressure or future design pressure greater than 60 psig must be reviewed and stamped by a professional engineer. The engineer

⁴⁹ The Class Location Program is discussed in detail in Chapter 4B of PG&E's 2015 GT&S rate case.

(civil or mechanical) must be currently registered in the state of California and competent in pipeline engineering as designated by the manager responsible for the facilities. All design work performed by contractors is reviewed by a PG&E employee for quality and compliance.

d) Construction

49 CFR Part 192 Subparts E, F, G and J specify the minimum requirements for the construction and testing of transmission and distribution facilities, including the welding and joining of pipe and components as well as the protection of the pipe and facilities from hazards such as unstable soil, landslides, and other hazards that may cause the pipe to move or sustain abnormal loads. PG&E's transmission and distribution pipe and facilities are constructed in accordance with these requirements.

e) Installation

49 CFR Part 192 Subpart H specifies the minimum requirements for the installation of distribution service lines, service regulators, and customer meters. These requirements include specifications pertaining to the location of this infrastructure, protection from damage, and valve requirements. PG&E's service lines, service regulators, and customer meters are to be installed in accordance with these requirements.

f) Maintenance

49 CFR Part 192 Subparts M and I specify the minimum requirements for the maintenance of transmission and distribution pipe facilities along with the associated corrosion protection facilities. Maintenance activities include the patrolling of pipeline, performing leakage surveys, monitoring performance of corrosion protection systems, making repairs, inspection and testing of pressure limiting and regulating equipment, and valve and vault inspection and upkeep. PG&E maintains its pipelines and facilities in accordance with these requirements.

g) Operations

49 CFR Part 192 Subparts L and K specify the minimum requirements for the operation of transmission and distribution pipeline facilities. Operational activities include the Emergency Response Plan as well as requirements for a public awareness program, damage prevention program, CRM procedures, odorization of gas, identification of changes in population density along certain transmission lines, and the determination of MAOP including requirements for increasing the MAOP. PG&E operates its pipelines and facilities in accordance with these requirements.

h) Odorization

All gas leaving PG&E's transmission and distribution systems is odorized such that it can be readily detected at concentrations of one-fifth of the lower explosive limit by a person with a normal sense of smell. To ensure the gas is properly odorized, PG&E operates and maintains numerous odorizers (odorant injection equipment) throughout the gathering, transmission, and distribution pipelines, and storage facilities, to inject a suitable amount of odorant into the gas systems to comply with CFR 49 Part 192.625 for our downstream customers and to meet Class 3 and 4 requirements. As new pipelines, facilities, and operational changes occur the odorant strategy is reviewed for compliance and appropriate action is taken.

To certify that the gas is properly odorized PG&E conducts periodic odor intensity (sniff) tests at key points in the system per PG&E standards. In addition, online sulfur analyzers continually monitor the gas at critical locations to ensure there is sufficient odorant in the gas stream. When the analyzer readings reach a low or high level limit, alarms are sent to Gas Control for corrective action. All deviations in odor intensity are quickly addressed to ensure the safety of PG&E's customers.

2. Records Quality and Information Management

PG&E is taking a three-step approach to enhance records quality that: (1) starts with the initial baseline validation; (2) includes continual validation through field verification and; (3) consists of improving records management processes. Each of the three steps includes various initiatives that have been completed or are currently in progress.

Initial Baseline Validation

Several examples of completed initiatives include:

- Maximum Allowable Operating Pressure (MAOP) validation project consisting of validating the safe operating pressure of 6,750 miles of transmission pipelines by reviewing more than 4 million records and including this information in PG&E's new Gas Transmission Geographic Information System⁵⁰ (GT GIS).
- Pipeline centerline survey project consisting of capturing survey-grade information regarding the spatial accuracy of 6,750 miles of transmission pipelines by field locating and marking the pipeline and capturing the associated GPS coordinates which will also be included in PG&E's new GT GIS.

50 GIS is a computer system designed to capture, store, analyze, manage and present all types of geospatial or geographic data.

- Comparing the customer care billing database that includes meter locations with distribution asset maps to identify any distribution services and associated mains that may not have been included on the respective distribution asset maps.

In addition, PG&E is currently half-way through a three-year effort commenced in 2012, Pathfinder Project, to convert distribution system asset data for PG&E's 42,000 miles of distribution mains and 3.3 million distribution services. This includes resolving any discrepancies between work orders, installation year, coating type, size, material and other relevant attributes.

Continual Validation Through Field Verification

Initiatives under field verification include ongoing efforts to compare (1) asset data captured as part of performing field inspections for both transmission and distribution on H-forms and A-forms; and (2) asset data captured as part of conducting in-line inspections for transmission pipelines, with GIS data.

Improving Records Management Processes

Initiatives under improving records management processes include enhancing (1) gas asset mapping duration; (2) employee and contractor awareness of identifying any records discrepancies and reporting it through CAP; and (3) process safety controls for validating asset information during design and prior to construction analogous to a "pre-flight" safety checklist.

In addition, PG&E's Gas Operations RIM team is focused on providing overall governance of the records management program. This includes publishing Records Management Standards such as the two issued in 2013, *Gas Operations Records and Information Standard* and the *Gas Operations Vital Records Standard*. These Gas Operations standards align with corporate policy and define the requirements for the maintenance, storage and disposition of official records.

In May 2014, the Gas Operations RIM team developed a comprehensive roadmap to move Gas Operations toward achieving compliance with ARMA International's Information Governance Maturity Model Level 3, a compilation of generally accepted recordkeeping principles® as well as supporting Gas Operations continued certification of PAS 55-1 and ISO 55001, both of which relate to asset management and require sound records and information management processes. The Gas Operations RIM roadmap also addresses other requirements, observations and commitments made around Gas Operations records management, providing a holistic approach to improving Gas Operations records management overall.

In 2014, Gas Operations established a RIM Coordinator network to facilitate communications between the Gas Operations RIM team and the field offices. Each field office has an assigned RIM Coordinator that works closely with the Gas Operations RIM team and functions as the local subject matter expert on records management for their respective field office including providing oversight of records storage and ongoing management. Currently, there are 106 coordinators covering approximately 140 field offices. The Gas Operations RIM team provides targeted training to the coordinators and supports them as they coach field office employees in meeting PG&E's recordkeeping requirements.

Each of the steps and initiatives outlined above are keys to enhancing PG&E's records quality and yet another critical aspect of becoming the safest, most reliable gas company in the nation.

D. Continuous Improvement

1. Quality Assurance and Quality Control

In addition to building QA and QC into processes at PG&E, the QA and QC group is responsible for centralized QC and QA activities (formerly the Quality and Improvement department). The QC activities include quality verifications through field assessments either in real-time (as work is being performed) or after-the-fact. In 2013, PG&E had six fully operational QC programs for Leak Survey, Leak Repair, Locate and Mark, Distribution Construction, Transmission Construction, and Field Service. Starting in 2014, PG&E added additional programs for Regulator Station Maintenance, Valve Maintenance, Rotary Meter Maintenance, and Corrosion Control, bringing the total number of programs to ten. The approach consists of using a combination of random statistical sampling and targeted sampling of work across our service territory to evaluate performance against key quality attributes for each program and improve performance. QC activities will continue to be evaluated and updated relative to system safety and compliance risks in order to continuously achieve the greatest amount of risk reduction and improve safety and asset performance.

QA activities include audits of PG&E's processes and programs. The audit process was documented and improved to meet the PAS 55-1 and ISO 55001 certification requirements. QA activities also include expanding into developing and implementing an overarching framework for building quality into the work that is performed by PG&E in the line organizations, implementing quality metrics, and driving continuous improvement utilizing Gas Operation's CAP program. Gas Operation's CAP is described in Section III.B.1.

2. Research and Development

Research and Development (R&D), and Innovation detects, adapts, qualifies and implements innovative solutions in the Gas Operations business to improve its performance measured in public and work safety, customer satisfaction, environmental impact, regulatory compliance, communication, and cost effectiveness.

The R&D and Innovation program is embedded in Gas Operations through the continuous improvement process, assuring that projects and innovations align with the most critical needs of the business. Each R&D project is assessed using multiple criteria that not only weighs its strengths and weaknesses to justify decisions but also defines the actions that must be engaged early in the life cycle to prepare its successful deployment. As a result, the R&D and Innovation program manages a portfolio of projects that balances short (1 year) and long-term objectives (3 to 5 years).

In order to optimize resource allocations, R&D and Innovation participates in numerous collaborative efforts through national and international R&D organizations such as Pipeline Research Council International, NYSEARCH, and Operations Technology Development (Gas Technology Institute). In addition, R&D monitors the emerging technologies developed through PHMSA's collaborative R&D program as well as the California Energy Commission, which assigns a specific budget allocation to Gas Pipeline Integrity improvement within its Public Interest Energy Research program.

3. Leak Optimization Pilot (Super Crew)

In 2014, PG&E created the leak optimization pilot team, which is called Super Crew. This pilot program established a new process model to help work flow more efficiently across teams focused on performing leak survey and leak repair. The Super Crew is made up of representatives from all functional workgroups within the leak management process including leak surveyors, mapping specialists, estimators, and construction crews. PG&E is using state-of-the-art leak detection technology to detect more leaks and bundling repair activities to find leaks and fix them faster and more efficiently than ever before.

For example, the Super Crew team was able to leak survey 107,000 services and repair over 3,100 leaks (including repairing meter set leaks and replacing 77% of all leaking services) in only 41 business days.

4. Benchmarking and Best Practices

PG&E uses industry benchmarking as a way to identify best practices, which includes, but is not limited to, widely-recognized natural gas practices that directly enhance public and personnel safety over time. Benchmarking is one component of understanding what may

constitute an industry best practice, and is accomplished by both formal and informal means. There may also be more than one single industry “best practice” in any given program area. Therefore, PG&E’s best practice identification often begins with identifying a published industry standard that provides guidance and sets overall direction for a program or technical discipline and discussing with other utilities. When standards are not readily identifiable, PG&E may employ various methods, such as reaching out to industry associations, experts, and other utilities, to discuss best program approaches, and then develop detailed procedure manuals to document the practices. PG&E relies on various outlets for benchmarking best practices such as reviewing standards written by SMEs and public agency publications, and participating in industry associations. How PG&E utilizes each of these outlets is described in the next sections.

a. 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 United States, PG&E identifies international standards for best practices, including European and International Standards Organization. PG&E has adopted for use several European standards. In another example, PG&E pursued the certification of ISO 55000, the recently available international asset management standard. Which PG&E applied for and recently received the ISO 55001 certification.

PG&E relies on the ASME, an association of more than 130,000 members in 158 countries, to facilitate the development of best practices, prescribe codes and standards for the gas transmission industry, to provide forums such as conferences and meetings for like-members to learn about relevant best practices, publish best practice literature, and to provide technical continuing education. Some of PG&E’s foundational risk management and gas transmission program activities follow ASME standards that are referenced in code, such as B31.8S, Managing System Integrity of Pipeline Systems.

PG&E relies on the API, a national trade association representing the interests of the oil and natural gas industry to develop and publish best practice standards, publish industry reports, provide continuing technical education, provide forums such as conferences and meetings for like-members to learn about relevant best practices, and to publish relevant industry statistics. Some of PG&E’s foundational gas transmission program activities follow API industry consensus standards that are referenced in code, such as Recommended Practice 1162, Public Awareness Programs.

b. Agency Publications

PG&E reviews relevant agency documents to gain insights into what regulatory and investigation agencies view as best practices. PG&E incorporates input from previous proceedings and reviews, including the CPUC, the National Transportation Safety Board, PHMSA, and other Independent reviewers contracted by these entities.

As an example, PG&E has a procedure to ensure appropriate responses to all PHMSA advisories and any proposed or final rulemaking notices from other regulatory agencies. The procedure expedites reviewing, assigning, and tracking of all gas transmission and distribution-related advisory bulletins and proposed or final rulemaking notices from any regulatory agency in a timely manner. These include all bulletins and notices affecting engineering, construction, operations, maintenance, and emergency response activities or procedures. Additionally, the procedure ensures that any actions or changes needed to address the bulletins or notices are identified and completed in a timely manner.

c. Peer Associations

Benchmarking is performed with a variety of utility and non-utility entities to improve our understanding of how other companies manage various operational programs, including best practices related to safety. For instance, PG&E personnel learn about best practices from interacting with peers and industry experts in organizations such as the Interstate Natural Gas Association of America (INGAA), American Gas Association (AGA), NACE International (formerly known as the National Association of Corrosion Engineers), API, ASME, Southern Gas Association (SGA) and other organizations.

PG&E employees participate in and present at a variety of industry conferences including AGA, SGA, NACE, Western Energy Institute (WEI), Common Ground Alliance, Western Regional Gas, International Pipeline Conference and World Gas 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.

a) American Gas Association

PG&E is an active member of the AGA and participates on numerous AGA committees as shown below in **Table 5**.

**TABLE 5 – AGA COMMITTEES
PACIFIC GAS AND ELECTRIC COMPANY**

AGA Participation	
Best Practices	
Steering Committee Member	Program Coordinator
Operations Committees	
Operating Section Managing Committee	Plastic Materials Committee
Building Energy Codes & Standards	Safety & Occupational Health Committee
Corrosion Control Committee	Supplemental Gas Committee
Distribution & Transmission Engineering	Transmission Measurement Committee
Distribution Construction & Maintenance	Transmission Pipeline Operations Committee
Distribution Measurement Committee	Underground Storage Committee
Gas Control Committee	Utility and Customer Field Services Committee
Operating Safety Regulatory Action Committee	
Discussion Groups	
Public Awareness	Contractor Management and Quality
Combine GPS/GIS with Work Management	Damage Prevention
Technical Training and Knowledge Transfer	Odorization

Additionally, PG&E participates in the AGA SOS Survey Program. These surveys are topic-specific benchmarking requests initiated by gas companies through AGA for quick responses. PG&E responds to and distributes surveys throughout the year and utilizes the process to gauge industry best practices in a specific area. Finally, in 2013, PG&E and several other member companies piloted a “peer-to-peer” information exchange concept modeled on an Institute of Nuclear Policy Organization practice.

b) Interstate Natural Gas Association of America

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

c) 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 cathodic protection and coatings. NACE International creates these materials through the subject matter expertise of its members. NACE International has over 28,000 members in over 100 countries.

d) 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 and the company's president is a member of the Board of Directors.

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 talking to peers in the industry.

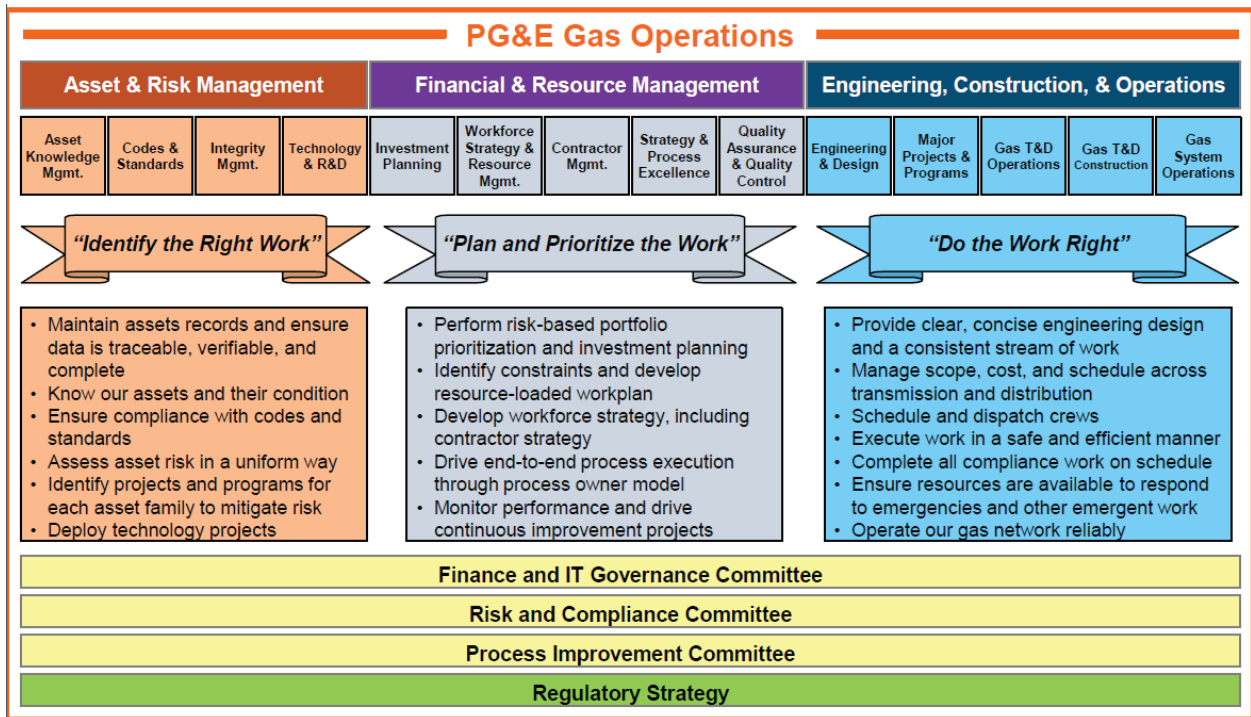
E. Employee Workforce and Training

1. Workforce Size

Having an appropriately sized workforce and access to qualified contractors is an important aspect of performing work safely and ensuring the safety of our gas system. The size of the workforce is determined by the work need to address public safety by identifying the right work, planning and prioritizing the work, and performing the work right. These steps ensure work flows through our organization in a clear and efficient manner.

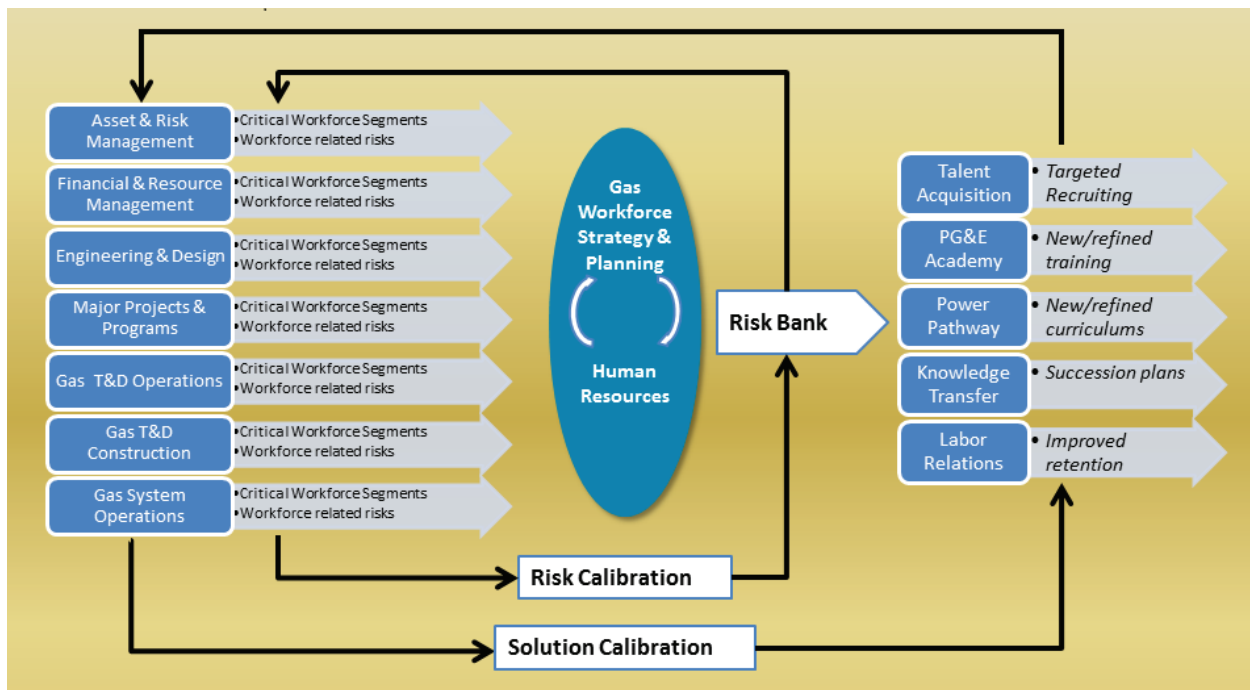
The Gas Operations operating model is shown in **Figure 7**.

**FIGURE 7 – GAS OPERATIONS OPERATING MODULE
PACIFIC GAS AND ELECTRIC COMPANY**



PG&E continually works to identify resource needs, and recruits, hires and trains professionals from throughout the industry. PG&E’s gas workforce strategy uses a risk based planning approach to identify critical areas that need resources. The strategy outlined in **Figure 8** details the process by which the workforce strategy is determined and shows how the risks drive the solution.

**FIGURE 8 – WORKFORCE STRATEGY OUTLINE
PACIFIC GAS AND ELECTRIC COMPANY**



Through 2014, PG&E plans to hire an additional 1,400 gas employees. This increase in Gas Operations employees supports the focus on safety and compliance through the successful execution of operating improvements and investment plans for both gas transmission and distribution assets.

2. Employee Training

The cornerstone to ensuring PG&E’s gas facilities are designed, constructed, maintained, operated, and retired in a safe and reliable manner is maintaining a workforce of highly skilled, competent and experienced technical employees. Prioritization of training program improvements is determined and driven by regulatory changes, new tools and instruments, standards and policy changes and strengthened OQ requirements.

In early 2012, PG&E finished a comprehensive benchmark study that compared PG&E’s gas training to others utilities. Three recommendations were made in support of employee training and PG&E’s Gas Operations training program identified approximately 100 courses that would be developed and/or enhanced between 2012 and 2016. The three recommendations and their status of June 2014 are included in **Table 6** below.

As of Quarter 2 2014, 59 new course publications include:

- 17 courses upgraded to improve the quality of training
- 10 courses migrated from the line of business into the training organization to deliver

- 17 brand new courses built based on gaps identified by the benchmark study and verified by the line of business
- 4 courses targeted for refresher training
- 11 courses where vendors were identified as having training that met PG&E's needs

The relationship between training and gas operations continues to strengthen, as a training governance committee is currently studying end-to-end program health from guidance documents-to training-to qualifications-to QC, for key programs such as Corrosion and Field Services. This study will guide the efforts to maintain a skilled and competent workforce.

**TABLE 6 – GAS OPERATION TRAINING RECOMMENDATIONS 2012-2016
PACIFIC GAS AND ELECTRIC COMPANY**

2012 Recommendation	Progress to Date (June 2014)
Develop programs that support employees throughout their career	<ul style="list-style-type: none"> • 72% of courses developed target existing employees. • Job skills training for existing employees will continue to be a bulk of the work in 2014; with new and changing guidance documents, changing organizational structure, and changes to lines of progression. • Redesigned the welding apprenticeship program, focusing on both knowledge and skill based learning. The result will be well-rounded journeymen that can demonstrate both welding proficiency and understanding of the science behind welding.
Broaden technology solutions and leverage external curriculum	<ul style="list-style-type: none"> • 41% of curriculum built in 2013 was web-based or other technology based medium • 25% of curriculum were vendor delivered or leveraged curriculum outside of PG&E.
Implement continuous training improvement processes	<ul style="list-style-type: none"> • In 2013, Gas Operations Training implemented: • Rapid design tools and processes which improved the speed for curriculum development while maintaining quality. • A Curriculum Advisory Committee which oversees the quality of the curriculum, advises project teams when to buy curriculum versus build and shares lessons learned and best practices across projects. • Training Effectiveness studies in partnership with QC to determine how effective key training programs are and how to improve them.

3. Operator Qualifications

The PG&E Gas OQ Plan requires all individuals who operate and maintain pipeline facilities meet specific safety requirements (including meeting 49 CFR Part 192 Subpart N). Employees must be qualified, and able to recognize and react appropriately to abnormal operating conditions that may indicate a dangerous situation or a condition exceeding design limits.

PG&E's OQ standard identifies required operating and maintenance tasks, provides guidance for achieving compliance with the requirements of 49 CFR Part 192 Subpart N, establishes qualification methods for performing covered tasks on a gas pipeline facility and identifies covered tasks/subtasks.

Testing requirements include knowledge and performance evaluations. The knowledge evaluation (written and/ or oral test) verifies that the employee understands the standards and procedures. The performance evaluation verifies the application of the employee's knowledge. PG&E continuously monitors the status of employees who must be qualified, and will be implementing improvements for tracking and reporting.

PG&E published an OQ standard that replaced the current OQ plan. The new standard, based on the ASME best practice standard, B-31Q, includes:

- Identifying approved evaluation methods for both initial and subsequent qualifications. PG&E moved a portion of their OQ evaluations to scripted oral performance based. Performance based evaluations for many of our tasks provide better insight into an employee's Knowledge, Skills, and Abilities.
- Setting requalification intervals at 3 years, instead of 5 years. This change aligns with industry best practices and gives the employee opportunities to validate their technical competence.
- Clarifying that the approved Span of Control ratio for an operator qualified individual to oversee the work of other non-qualified personnel is 1:1. This was not clear in our original document, so clarity was provided.
- Requirements for suspending or removing an OQ. Suspending and removing OQ's is an integral part of our OQ program. This ability is empowered to all supervision personnel who either believe their employees can no longer perform the task safely, and efficiently, or the employee no longer requires the OQ. The new standard provides better guidance based on ASME B-31Q standard, as to when to remove or suspend an employee's qualifications.
- Specifying the responsibilities for communicating changes in company guidance documents that affect the OQ program. The language in the new standard was enhanced and clarified to ensure all affected departments are aligned with the requirements of the OQ program.
- Provisions for addressing OQ personnel acquired as part of a merger or acquisition of another company. The provision was added to clarify the language in the OQ plan to align with ASME B 31Q.
- Language to address the OQ expiration term for contract personnel.

- Specifying that all evaluation methods are administered in English, in alignment with industry best practices.

As part of the new standard, six new procedures were developed:

- Procedures defining OQ administration
- Procedures addressing roles and responsibilities and scheduling of OQ evaluations
- Procedures documenting the evaluation processes
- Procedure documenting the OQ suspension process and requirements

4. Contractor Safety, Training, and Oversight

Much like full-time PG&E employees contractors are also a cornerstone in ensuring PG&E's workforce consists of highly skilled, competent, and experienced technical personnel. Prior to starting a job, PG&E confirms that contractors, and subcontractors, are qualified to complete the contracted work. Contractor's Safety Programs are reviewed by internal and external organizations to evaluate the content, qualifications, and industry metrics, including but not limited to, OSHA Recordable Incident Rate, Total Incident Rate, Lost-Work Days, Restrictions and Transfers and Experience Modification Rate. Contractors on major projects are also given site specific awareness orientations or specific information about the job, which is provided in person at the job-site and through computer based training managed by a third-party. The computer based training covers PG&E's safety expectations and typical hazards associated with the work. There is also a module on Gas Safety Excellence, which is instrumental in communicating PG&E's expectations around quality and safety.

Once construction on a major project has started, PG&E oversees the contractor's performance and clearly communicates contract terms that hold contractors accountable for safety quality. This is done through regular job-site observations and meetings with the contractors to ensure their success. Job-site observations start during the pre-job walk-throughs to evaluate site specific hazards prior to starting work. PG&E schedules regular meetings with contractors to ensure expectations are met. Meetings consist of overall performance feedback, sharing of best practices, lessons learned, communication of new processes, and trends seen in the field. On a quarterly basis, PG&E's leadership and contractor leadership meet to discuss overall performance at a Company level. PG&E engages their leadership to understand potential opportunities to improve the overall program.

At all of the meetings, contractors are provided a dashboard on metrics that they are measured on. These metrics are communicated at the beginning of the year and managed throughout the year to ensure their success. Metrics include, At-Fault Dig in Rate, Public Safety, Near-hits, OSHA Recordable Injuries, Lost Work Day Cases and Preventable Motor Vehicle Incidents. The metrics are compared against and established to match Gas Operations

Safety metrics and industry standards. After the job is completed, PG&E evaluates the contractor's performance utilizing a scorecard developed by PG&E Sourcing department. The scorecard includes Safety performance and other contractual obligations. The purpose of the scorecard is to evaluate and manage contractors for future work.

5. Partnership With Local Unions

Union-represented employees make up almost 70% of PG&E's workforce, and are integral in the Company providing safe, and reliable gas service. As such, PG&E works collaboratively with its union partners to ensure its union-represented employees have a stable and productive work environment, and are able to voice their concerns to improve their jobs. In 2014, PG&E has been collaborating with union leadership on various projects such as updating the lines of progression, Mapping Advancement Program, and PG&E's leak survey optimization program.

The line of progression effort will update job duties, training and certification for almost every represented field based position. The line of progression changes will help thousands of union-represented employees have a clear vision of their career paths and the training necessary for these new roles.

Updating the Mapping Advancement Program entails a rewrite of PG&E's mapping training for union-represented mapping employees. PG&E developed a team of SME's (which were all union-represented employees), PG&E's Planning & Support team and Learning Academy to support this effort and update the program. The Mapping Advancement Program will enhance the required training program for all of our mapping technicians in order to progress to the senior mapping technician classification. Once the program is updated, it will help maintain the program with our changing business needs resulting in improved mapping, enhanced records, and safer operations. We are also developing a training program for Field Engineers and Field Engineer Technicians. This is a collaborative effort that involves union represented SME's and management. Once this training is complete, it will provide consistency and standardization to training new employees.

Another important example of collaboration between PG&E and union leaders is the leak optimization program, which incorporates advanced leak detection technology, and includes a streamlined and bundled approach to finding and fixing leaks. The benefits of this program include a significant reduction in leaks, improved work performance, enhanced system reliability, and increased public safety. Further, we are partnering with our union partners additional safety-related improvements, such as enhanced crew coverage, and the on-call processes to further improve response time, as well as use of GPS to confirm worker location.

III. PG&E's Safety Culture

A. PG&E's Corporate Safety Committees

PG&E recognizes that promoting a safety-first organization requires clearly articulated roles and responsibilities, highly-engaged employees, a skilled workforce, sufficient resources to successfully execute on investment plans, standards and procedures written in readily understood English, a rigorous QA/QC program, and a clear understanding of regulatory and industry requirements. PG&E is focused on implementing safety enhancement measures to provide safe and reliable service to its customers and a safe work environment for our employees. In order to foster these relationships PG&E has many committees dedicated to specific programs to ensure safety principles are established and followed. **Figure 9** illustrates the interrelationship between PG&E's Corporate and individual Line of Business safety committees.

**FIGURE 9 – SAFETY COMMITTEES
PACIFIC GAS AND ELECTRIC COMPANY**



PG&E's Board of Directors established the Nuclear, Operations, and Safety Committee, which is chaired by a member of the Board of Directors and has a primary focus on public and employee safety. The Committee's charter (**Attachment 18**) lays out the Committee's focus on public and employee safety, compliance, and risk management policies and practices (including integrity management for Gas Operations). Senior leaders, in particular those in Gas Operations, regularly engage the Board of Directors in discussions regarding safety.

The Chairman's Safety Council replaces the Chairman's Safety Review and the Executive Safety Steering Committees as outlined in **Attachment 19**. The Chairman's Safety Council is under the leadership of PG&E's Chief Executive Officer and is responsible for reinforcing the role of safety in all aspects of operations, and the PG&E's relationships with customers, the public, employees, and suppliers. The Chairman's Safety Council also reviews the company's overall safety strategy and its implementation.

The Gas Operations Safety Council is sponsored by the Senior Vice President of Engineering, Construction, & Operations. The Safety Council is a newly formed committee that provides overall governance of safety for the LOB, guides the department safety strategy, ensures compliance with Company safety standards, executes the Chairman's Safety Council's directives, and promotes positive safety culture change throughout Gas Operations. Members of the Safety Council include PG&E's Leadership, safety leads from Gas Operations departments, bargaining unit leads, a corporate safety culture lead, and Grassroots Safety team leads.

The Gas Operations Risk and Compliance Committee (**Attachment 20**) is chaired by the Executive Vice President of Gas Operations. This committee reviews all operations and processes within Gas Operations and the associated risks, including risks related to public safety. The committee also tracks progress and mitigation activities.

B. Employee Engagement

Engaging the workforce means demonstrating to all employees that the company values their ideas, input, and personal development, including providing training opportunities. PG&E created a strong line of sight between organizational objectives and the work performed on the gas asset system by employees. By aligning corporate strategies and work plans, PG&E supports a much more fluid bottom-up flow of ideas and feedback to enable continuous improvement in the business.

Gas Operation's executive leadership team visits offices and field locations to speak directly with employees and hear firsthand their thoughts on what PG&E is doing well and where improvements are needed. However, talking to and listening to employees alone is not enough to demonstrate to employees that PG&E's leadership wants their input and ideas of how to improve. To show the focus on engagement, PG&E leadership has created specific engagement activities around key aspects of work heavily leveraging employee feedback. The selection of new gas crew trucks that are replacing the aging fleet were almost entirely led by field employees. PG&E is in the process of building a new gas training facility with extensive employee engagement around design, layout, training areas, and equipment. Additionally, course content and technology are being led by cross functional employee teams. The company is also working hard to close the feedback loop by developing easy-to-use and centralized mechanisms to obtain employee feedback using the CAP. Gas Operations is using this information to develop processes to ensure meaningful employee input is incorporated into operations decisions.

PG&E also has established gas technical teams and Grassroots Safety Teams, which provide additional channels for obtaining input and recommendations on Gas Operation's processes.

1. Corrective Action Program

As part of PG&E's Gas Safety Excellence strategy PG&E implemented a risk-based CAP in 2013. CAP is the process that provides PG&E personnel—both employees and contractors—with the ability to identify and document issues found within the Gas System. CAP is also the means by which an employee can submit comments about the current state of the Gas Safety Plan. Employees have three methods to submit CAP items: (1) Employees can enter CAP items through a Toll-Free number; (2) web-portal via PG&E intranet; or (3) by paper submission.

CAP collects all gas related issues, concerns, and ideas (including operational events, audit findings, employee feedback and improvement ideas) in a central place. Issues submitted to CAP undergo a risk-based evaluation to determine the underlying cause. The issues are then prioritized based on the risk assessment tool (**Attachment 21**), and tasks are tracked in CAP through to completion (**Attachment 22**).

Each CAP Item is reviewed to ensure adequate information is provided and is effectively titled, risk ranked, categorized, and assigned to a work center. CAP Team Members are assigned work centers to coach work group evaluations, corrective action development, documentation, tracking, and closure. Any resulting corrective and preventive actions are tracked to completion. Upon the completion of a Critical or High Risk issue, each notification has an "Effectiveness Assessment" conducted within 6 to 12 months to ensure the effectiveness of the CAP item's countermeasure.

Objectives of the CAP Include:

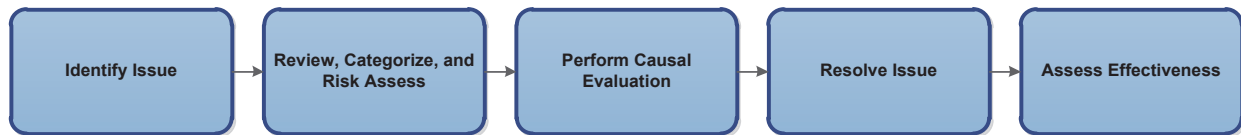
- Identifying problems, issues, concerns, and opportunities for improvement.
- Evaluating, classifying, analyzing, and investigating these issues.
- Developing and implementing corrective and preventive action plans.

Items submitted through CAP can come from a variety of sources including, but not limited to, the following items:

- Safety-related conditions.
- Gas incidents and emergency response exercises.
- Internal, external, and third-party audit findings.
- Equipment failures.
- Regulatory violations and reportable incidents.
- Advisory recommendations.
- Overpressure events.

The CAP process (**Figure 10**) allows for rigorous problem solving so that causes are properly identified and solutions are effective in eliminating those causes. An important part of CAP is quickly sharing information and lessons learned – which will support continuous learning and improve the safety of our operations.

**FIGURE 10 – CAP PROCESS
PACIFIC GAS AND ELECTRIC COMPANY**



Real-time reports enable detailed analysis and trending, which can help to prevent recurrences and improve the availability of gas assets, the safety of the public and personnel, and the reliability of the gas system. CAP provides transparent tracing of issues from identification through resolution and anonymous feedback capabilities.

The CAP Team Communication Campaign and User Training started training employees in October 2013 and completed user training for all Gas Operation’s Employees by July 2014. Since initiating CAP in 2013, there have been over 1,500 issues submitted by gas operations employees. Each closed issue brings PG&E one-step closer to achieving PG&E’s goal of being the “safest and most reliable utility in the nation.”

2. Compliance and Ethics Helpline

PG&E’s Compliance and Ethics Helpline is available to employees, contractors, consultants, and suppliers 24 hours a day, 7 days a week. The Helpline can be used for both guidance on conduct matters and legal and regulatory requirements or to report situations that may require investigation. Callers have the option of remaining anonymous with any call. In addition to the Helpline channel, the following methods are available to raise concerns and ask for guidance on a range of company policy topics:

- 24-hour Helpline phone service (third party managed)
- Web-based submittal service (third party managed)
- Letter, phone call, email message (including through the Compliance and Ethics Helpline mailbox), fax, or personal meeting with Compliance and Ethics staff

All concerns and questions are tracked, managed and prioritized to ensure identification of dispositions and solutions. All calls and emails received by the third-party vendor are prioritized to determine if immediate action is needed. Priority “A” calls require immediate action as defined by CDT-3001P-02, C&E Helpline Priority “A” Response Handling Procedure (**Attachment 23**).

3. Material Problem Reporting

In addition to the Helpline and CAP, PG&E maintains a material problem reporting (MPR) system that allows employees to report problems with any materials, tools, gas/electric/other equipment or infrastructure, and vehicles. Each MPR is logged in the appropriate database and reviewed by a subject matter expert to identify improvements. The Material Problem Reporting allows trends to be identified in a timely manner so that actions can be taken with emerging material problems. The system is used by field employees and receiving inspection personnel. Each write up is fully reviewed and responded to by an engineer. The submitter of the MPR and the writer receives feedback from that engineer in written form.

4. Grassroots Safety Teams

The grassroots safety philosophy hinges on management and union-represented employees sharing responsibility for safe practices and implementation of corrective actions. Leadership is the key to safety performance, and safety leadership comes from all levels of an organization. This team is an employee-led effort that promotes safe work habits, shares information and best practices, promotes open and honest communications, and finds innovative methods to perform work safely. Grassroots members, at all levels, have direct influence on the development and implementation of initiatives developed by the Senior Leadership.

The companywide Grassroots Safety Team structure allows for the sharing of grassroots based ideas across all LOB in order to identify best practices and improve safety performance. Each LOB is committed to supporting and maintaining a functioning Grassroots Team to gather ideas and feedback from employees on safety issues. Grassroots team members discuss issues and solutions with all LOB representatives as well as senior leadership for PG&E. The lead from the Grassroots safety team serves as a liaison to the LOB Safety Council to ensure alignment across all safety teams.

5. Near Hits Reporting

A Near Hit is defined as an unplanned event that did not result in harm or injury to employees, contractors or the public, but could have done so. PG&E encourages employees to share unsafe occurrences and hazardous situations beyond their own work groups, yards and offices, so we can learn from one another, take action and prevent the incidents from happening again. Examples of a Near Hit include potential damage to equipment or property, disruption of service, or personal safety/hazard conditions such as driving.

Near Hit sharing, used in a preventive, non-punitive manner, is an effective way to reduce employee, contractor and public safety incidents and injuries. This approach also creates a

safety climate where employees look out for one another and prevent incidents from occurring to co-workers, contractors and the public. All employees are encouraged to submit near hits and can do so via the PG&E intranet site, mail, phone, fax, or by contacting one of PG&E's grassroots safety teams or their Union. Gas Operations uses the CAP to report near hits and those items are then reported up to the corporate Near Hit program to consolidate lists.

By sharing near hits openly, we can learn from one another and take the actions necessary to prevent future incidents and injuries. PG&E is committed to improving the safety of our employees, contractors and our communities.

IV. Process Safety

Process Safety is the prevention and mitigation of unintentional loss of containment (i.e., releases of potentially dangerous materials or energy) through the use of robust processes and good equipment reliability. It is a blend of engineering and management skills used in a systematic and structured approach to identify, understand, and mitigate hazards and risks, which could impact the public, employees, environment, and asset. Process Safety prevents catastrophic accidents. The goal of Process Safety is to develop effective processes and ensure employees fully understand the implications of what they are doing. Process Safety provides value to external and internal stakeholders including the public, customers, regulators, and employees in a variety of other industries.

Process Safety requires engaging stakeholders so they can understand the of vulnerabilities of our everyday work and commit to Process Safety, understand hazards and risk, manage risk and learn from experience to ensure the safety of gas assets and operations. The fundamental benefit of Process Safety is a safer business. To promote Process Safety, PG&E developed a Process Safety Management System, which includes engineering and administrative controls to protect employees, the public, the environment and/or the assets and reduce the chance of low probability/high consequence incidents.

To stimulate Process Safety Management excellence and continuous improvement, PG&E implemented a Risk-Based Process Safety (RBPS) framework developed by AIChE's CCPS.

The RBPS management system approach recognizes that all hazards and risks are not equal; consequently, it advocates that more resources should be focused on more significant hazards and higher risks. The RBPS management system approach is built on four foundational blocks, which are further divided into a total of 20 elements (see **Figure 11**). As part of the deployment of the RBPS management system approach, PG&E performed Process Safety benchmarking and gap analysis for all the Process Safety elements.

**FIGURE 11 – RISK BASED PROCESS SAFETY 20 ELEMENTS
PACIFIC GAS AND ELECTRIC COMPANY**



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

Process Safety Foundational Blocks and associated Elements that constitute a sturdy RBPS management system.

First Foundational Block: Commitment to Process Safety

Commitment to Process Safety is the cornerstone of Process Safety excellence. PG&E recognizes that generally an organization would not improve without strong leadership and solid commitment; as such management has shown commitment to Process Safety. PG&E is working towards seeking that same commitment from the entire organization. PG&E realizes that a workforce that is convinced the organization fully supports safety as a core value will tend to do the right things, in the right ways, at the right times, even when no one is looking. PG&E is committed to consistently and continuously nurture and support safe behavior throughout the organization. Once it is embedded in the company culture, this commitment to Process Safety can help sustain the focus on excellence in the more technical aspects of Process Safety. To support Commitment to Process Safety effort, PG&E has developed and deployed a new standard for Management of Change and developing new standards and procedures for PHA and PSSR. PG&E will continue to deploy and/or improve standards as related to Process

Safety in order to: (1) operate and maintain safe gas operation assets; (2) consistently implement Process Safety practices; and (3) minimize legal liability.

As part of Commitment to Process Safety, PG&E performed a formal external benchmarking and gap analysis for critical to success elements of Process Safety, including Process Safety Culture and Compliance to Standards. In addition, to promote improvement, closure of the gaps, and the drive towards maturity, PG&E developed Process Safety roadmaps for each of the elements part of the Commitment to Process Safety foundation block. The first five elements are:

1. *Process Safety Culture*⁵¹
2. *Compliance to Standards*⁵²
3. *Process Safety Competency*
4. *Workforce Involvement*
5. *Stakeholder Outreach*

Second Foundational Block: Understand Hazards and Risk

PG&E recognizes that organizations that understand hazards and risk are better able to allocate limited resources in the most effective manner. As such, PG&E has deployed HIRA and PHA in order to evaluate risks within the gas operation activities and assets. Both HIRA and PHA are used to identify hazards and evaluate risk of assets, throughout their life cycle, to make certain that risks to employees, the public, the environment and/or the assets are consistently controlled within a set risk tolerance. The HIRA and PHA typically address five risk questions to a level of detail commensurate with analysis objectives, life cycle stage, available information, and resources. Based upon the level of understanding of these answers, PG&E can decide what actions, if any, are needed to eliminate, reduce, or control existing risk. The five risk questions are:

- What can go wrong?
- How bad can it be?
- How often might it happen?
- Are the proper safeguards in place?
- How can I better manage risk?

Key activities where PG&E evaluates for risks include facility design and modification, operational procedures, workforce competence, human factors, emergency arrangements,

⁵¹ Critical to success Process Safety element for which a formal benchmarking study was performed.

⁵² Critical to success Process Safety element for which a formal benchmarking study was performed.

protective devices, instrumentation and alarms, inspection and maintenance, permit to work, asset records and data quality, and third-party activities.

As part of Understanding Hazards and Risk, PG&E performed a formal external benchmarking and gap analysis for critical to success elements of Process Safety, including Hazard Identification & Risk Analysis. In addition, to promote improvement, closure of the gaps and the drive towards maturity, PG&E developed Process Safety roadmaps for each of the elements part of the Understanding Hazards and Risk foundation block. The next two elements are:

6. *Process Knowledge Management*

7. *Hazard Identification & Risk Analysis*⁵³

PG&E commits to using hazard and risk information to plan, develop, and deploy stable, lower-risk operations in order to promote long term success and a safer business.

Third Foundational Block: Manage Risk

PG&E Manages Risks by focusing on three issues:

- Prudently operating and maintaining processes that pose the risk;
- Managing changes to those processes to ensure that the risk remains tolerable; and
- Preparing for, responding to, and managing incidents that do occur.

As such, PG&E has deployed the PSSR which helps ensure that risks have been identified and addressed; that there is agreement on all startup requirements including training, drawings, spare parts and operating procedures before starting new equipment and facilities; and that there are alternatives to address problems.

As part of Managing Risk, PG&E performed a formal external benchmarking and gap analysis for critical to success elements of Process Safety, including Asset Integrity and Reliability and MOC. In addition, to promote improvement, closure of the gaps and the drive towards maturity, PG&E developed Process Safety roadmaps for each of the elements part of the Managing Risk foundation block. Elements 8 through 16 are:

8. *Operating Procedures*

9. *Safe Work Practices*

10. *Asset Integrity & Reliability*⁵⁴

11. *Contractor Management*

12. *Training & Performance Assurance*

⁵³ Critical to success Process Safety element for which a formal benchmarking study was performed.

⁵⁴ Critical to success Process Safety element for which a formal benchmarking study was performed.

13. *Management of Change*⁵⁵
14. *Operational Readiness/Pre-Startup Safety Review*
15. *Conduct of Operations*
16. *Emergency Management*

PG&E recognizes that managing risk helps the company deploy management systems that help sustain long-term, incident-free, and profitable operations.

Fourth Foundational Block: Learn From Experience

Learning from Experience involves monitoring and acting on internal and external sources of information. Despite PG&E's best efforts, operations do not always proceed as planned, so PG&E is turning its mistakes – and those of others – into opportunities to improve Process Safety efforts. The ways to learn from experience that PG&E promotes are to: (1) apply best practices to make the most effective use of available resources; (2) correct deficiencies exposed by internal incidents and near hits; and (3) apply lessons learned from other organizations.

To support Learning from Experience effort, PG&E is reviewing and revising the current incident investigation process into an integral end-to-end process for Gas Operations in order to comply with regulatory requirements, include a Process Safety perspective and provide effective governance with stakeholders' role, responsibilities and accountability.

In addition to recognizing opportunities to better manage risk, PG&E's PSM system promotes for a Process Safety culture and infrastructure to help employees remember the lessons and apply them in the future. PG&E is developing the following metrics to provide timely feedback on the workings of RBPS management systems:

- Total Count of Process Safety Incidents
- Process Safety Total Incident Rate
- Near Hits Process Safety Events
- Mechanical Integrity
- Management of Change
- Action Items Follow-Up

PG&E recognizes that management review, a periodic honest self-evaluation, helps sustain existing performance and drive improvement in areas deemed important by management.

As part of Learning from Experience, PG&E performed a formal external benchmarking and gap analysis for critical to success elements of Process Safety, including Measurement and Metrics. In addition, to promote improvement, closure of the gaps and the drive towards

⁵⁵ Critical to success Process Safety element for which a formal benchmarking study was performed.

maturity, PG&E developed Process Safety roadmaps for each of the elements part of the Learning from Experience foundation block. The remaining four elements are:

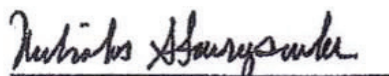
17. *Incident Investigation*
18. *Measurement & Metrics*⁵⁶
19. *Auditing*
20. *Management Review & Continuous Improvement*

V. Conclusion

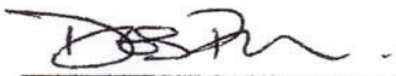
The 2014 Gas Safety Plan Update demonstrates how PG&E implements processes and procedures to achieve its commitment to becoming the safest and most reliable, natural gas company in the nation. The Gas Safety Excellence framework guides how PG&E operates, conducts, and manages all parts of its business by putting *safety* and people at the heart of everything it does; investing in the *reliability* and integrity of its gas system; and, by continuously improving the effectiveness and *affordability* of its processes. In addition, PG&E continuously invests in its facilities, employees, technology, and operations to enhance the long-term safety, reliability and affordability of its system.

⁵⁶ Critical to success Process Safety element for which a formal benchmarking study was performed.

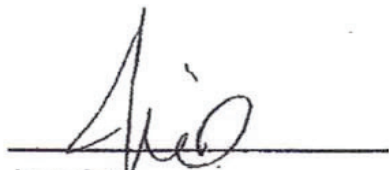
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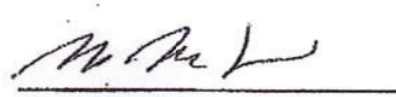
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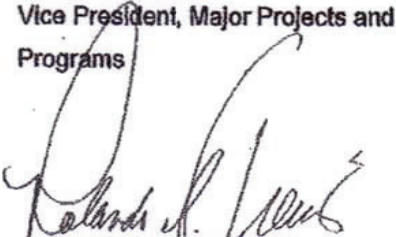
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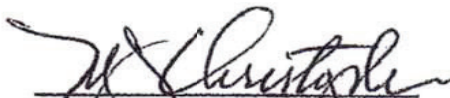
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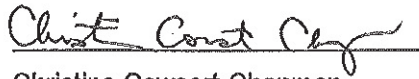
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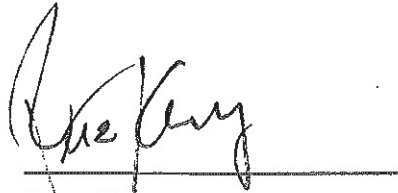


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APPENDIX B

(Appendix B consists of one (1) archival grade CD. The contents of the CD include Attachments 1 through 23 to Pacific Gas and Electric Company's 2014 Gas Safety Plan Update and Compliance Statement. The CD has been provided to the Commission's Docket Office for filing.)