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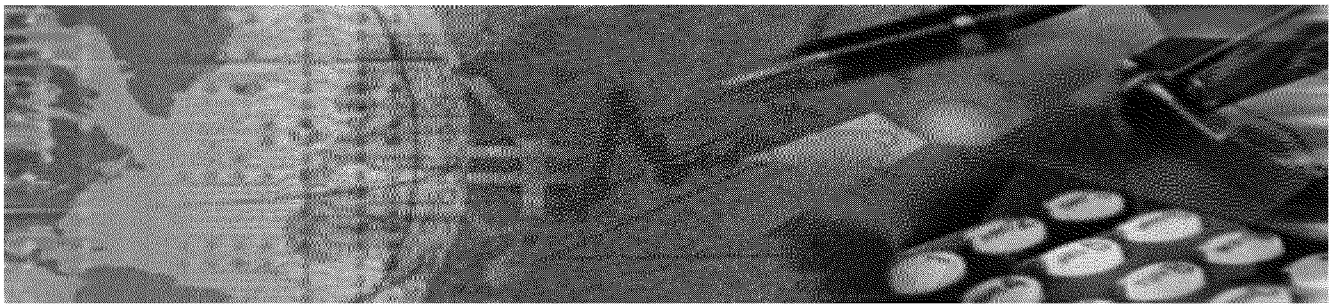
Assessment of Pacific Gas & Electric Company's Pipeline Safety Enhancement Plan



Prepared For Consumer Protection & Safety Division

December 23, 2011

Utilities Practice

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Assessment of Pacific Gas & Electric Company's Pipeline Safety Enhancement Plan

Prepared For

Consumer Protection & Safety Division

For Jacobs Consultancy,

Frank T. DiPalma
Director

December 23, 2011

Utilities Practice

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1.0 Executive Summary

1.1 Introduction

On August 26, 2011, in response to California Public Utilit ies Commission (CPUC or Commission) Decision (D).11-06-017, Pacific Gas & Electric Company (PG&E) submitted its Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan (Pipeline Safety Enhancement Plan or Implementation Plan or PSEP). The Implementation Plan is a multiphase, multiyear program that is in addition to PG&E's existing pipeline replacement and maintenance, risk mitigation, and integrity management programs.

The Implementation Plan has four major parts: pipeline modernization, valve automation, pipeline records integra tion, and interim safety enhancement measures. Expectations are that once fully implemented, PG&E's PSEP will significantly improve the level of integrity and operating safety associated with its natural gas transmission system.

1.2 Objective

The objective of this study was to review PG&E's Implementation Plan and determine if it is an appropriate response to the C ommission's D.11-06-017. Specifically , the proposed Implementation Plan must:

- Comply with the requirement that all in -service transmissi on pipelines have been pressure tested in accordance with 49 CFR 192.619, excluding 49 CFR 192.619 (c).
- Include a timetable for completion and interim safety enhancement measures for pipelines that must run at or near Maximum Allowable Operating Pressure, or above 30% System Minimum Yield Stress.
- State the criteria on which pipeline segments are identified for replacement rather than pressure testing.
- Contain a priority-ranked schedule for pressure testing pipeline not previously tested and for certain Maximum Allowable Operating Pressure reductions.
- Consider retrofitting pipeline to allow for in-line inspection tools and shutoff valves.
- Include expense and capital cost projections by component for each Plan year.
- Recommend a rate proposal with cost sharing between shareholder and ratepayer.
- Conduct workshops concerning the technical aspects of gas pipelines with representatives from Consumer Protection and Safety Division (CPSD) as participants.

1.3 Scope and Approach

Jacobs Consultancy was asked to review ce rtain aspects of PG&E's Implementation Plan. Specifically, to assess the Pipeline Modernization Implementation Plan's decision tree pipeline segment selection process, prioritization for pressure testing, use of remote control valves and automatic shutoff valves, pipeline records integration program , implementation plan program management approach and to comment on the overall reasonableness of PG&E's projected costs. We requested testimony, data and conducted a number of interviews with PG&E staff who auth ored, or are directly involved in executing the Pipeline Safety Enhancement Plan. In addition, we collaborated with the CPSD staff who participated in interviews, technical reviews and final report editing.

In formulating its opinion s Jacobs primari ly relied on the Commission's D.11-06-017 for stipulated requirements, its knowledge of existing industry standards and regulations and its expert judgment within the industry.

1.4 Conclusions and Recommendations

Using the approach outlined above , Jacobs Cons ultancy conducted its assessment in four prime focus areas of PG&E's Implementation Plan : Gas Transmission Pipeline Modernization Program, Gas Transmission Valve Automation Program, Pipeline Records Integration Program and Implementation Plan Management Ap proach and Estimate Risk Quantification. What follows is a brief summary of each area and our recommendations.

Gas Transmission Pipeline Modernization Program

Decision Tree Methodology

In order to define work to accomplish under the Implementation Pla n, PG&E developed decision trees using a deterministic threat model based on applicable pipe threats . PG&E developed a decision tree screening process to evaluate all 5,786 miles of PG&E's transmission pipeline for five relevant threat categories grouped into three individual decision tree queries. The individual decision tree queries are manufacturing defects for pre -1970 pipe; pipeline threats from fabrication and construction with a threshold date of 1960; and internal and external corrosion and latent third party or mechanical damage . PG&E uses pipe threats to determine a work prioritization system based on both known and unknown pipe segment properties. This allows the Company to assess and compare different parts of its transmission system based on threats and group them accordingly.

Prioritization Process

Work prioritization begins with the decision tree, which provides a phased high-level priority based on three threat group categories. The work is further prioritized by work type: pipe replacement, strength test and in-line inspection (ILI). This is complemented by consideration of population density, highest potential impact radius (PIR) per project segment and margin of safety. The annual schedule is developed by considering such factors as descending order of class location from Class 4 to Class 1, decreasing PIR's and percentage of high consequence area (HCA) pipe within each project. During Phase 1, which is currently underway, PG&E plans to complete approximately 350 projects.

This report found that PG&E's use of industry experts in the development of the threat based decision tree process provides a consistent and defined approach to validate threats ensuring that all decisions will be traceable and documented. PG&E has developed a prioritization and scheduling process that is flexible and addresses the safety aspects of the program, while attempting to reduce the disruption of gas supply to the customer. PG&E states that all US Department of Transportation defined transmission pipe will be evaluated through the Decision Tree process. At the time of Jacobs review, information to verify compliance with the decision tree and prioritization process was not available. In light of the ongoing dynamic nature of this process, periodically an audit will need to be conducted to verify the Decision Tree process results.

In developing a detailed MAOP database, PG&E has included data validation of all pipeline facilities. To date, not all pipeline facilities have been validated; therefore, PG&E has used existing GIS data, which may be not be accurate, towards planning included in its PSEP. In order to eliminate or minimize expenditures on pipeline replacement projects where updated data would not fully justify replacement, PG&E's engineering process, rightly, requires review of updated pipeline data to confirm to what capacity the need for the replacement project still exists.

In accordance with Commission General Order 112 (GO 112) for transmission pipe operating at or above 20% of its SMYS, and installed between 1961 and 1970, a strength test should have been conducted and records maintained to show compliance with GO 112. Where this is not the case and a new hydrotest is performed, the associated cost should be borne by the Company.

Our recommendation related to decision trees and prioritization is:

5.4.1 To ensure that PG&E is following their decision tree and prioritization process periodically an audit of a small number of projects should be undertaken to verify the process results.

5.4.2 PG&E should identify all transmission pipe installed between the effective dates of GO 112 and the federal regulations (generally between 1961 and 1970) where the strength test documentation is missing. For all such segments, the costs associated with all new pressure testing should be borne entirely by the Company.

Gas Transmission Valve Automation Program

Program Objectives

The Valve Automation Program will enable PG&E, either remotely or with local automatic control, to shut off the flow of gas quickly in response to a gas pipeline rupture that is detectible. The program addresses two types of automated valves that are intended to be employed: remote control valves (RCV) which shut-off gas flow after being remotely operated from the Gas Control Center and automatic shut-off valves (ASV) which have controls at the valve site and operate automatically to shut-off gas flow. To support the consistent placement of automated valves PG&E developed two decision trees for identifying segments for valve automation that consider population density and earthquake fault crossings. This program will also provide for replacement of mainline valves that impede the ability to use in-line devices to inspect for the integrity of the transmission pipeline system. The automation program will work in tandem with the Pipeline Modernization Program by focusing on areas where the potential consequences are greatest. PG&E proposes to implement the Valve Automation Program in two phases: Phase I, which runs from 2011 through 2014, will consist of approximately 228 isolation valves for replacement, automation or upgrade; and Phase II, which is intended to initiate in 2015, envisions automation of approximately an additional 330 valves.

While 49 CFR, Section 192.179(a), provides guidance for the installation of isolation valves, it does not specifically address spacing applicable to automated valves. However, PG&E used this regulation as a starting point for maximum spacing. In addition, PG&E conducted a study to examine how varying valve spacing impacts the time required to evacuate the gas through a break in the pipe after the section of pipe was isolated.

SCADA System Enhancements

PG&E will deploy systems and technologies that fully leverage valve automation to provide early warning of events, while preventing false valve closures. Gas Control operators will be given training, tools and information to allow for quicker detection and response to pipeline ruptures. SCADA enhancements will include additional information relating to pressure, flows and other critical gas system data; providing pressure measurement upstream and downstream of all automated valves, and other key sites. The enhancements will provide additional SCADA screens with more detailed information; additional information on manual valve positions; and implementing a new data historian and integrating GIS and SCADA with the data historian in order to provide gas operators with access to physical pipeline and geographical information.

This report found that PG&E's use of industry experts in the development of its valve decision tree process resulted in a verifiable, repeatable, and consistent approach in determining the locations for the placement of automated valves within its transmission pipeline system. This process will result in exceeding current industry accepted methods that establish an acceptable margin of pipeline safety. In addition, PG&E's proposed valve automation program exceeds the intentions of federal legislation currently under consideration. Consequently, PG&E should fully define the anticipated benefits of the Valve Automation Program from a risk avoidance perspective.

The decision trees employed by PG&E define RCV valve automation recommendations by population density and ASV's by earthquake fault crossings. However, pipeline industry experience has demonstrated a strong preference for RCVs over ASVs because of false closure issues related to ASVs . Consequently, we believe this issue warrants further research into the ASV's false clos ure rates and c ontinuing monitoring of the evolving state of ASV technology . Wherever ASVs are subsequently used, PG&E should develop contingency plans to respond to any adverse effects that may result from false closure of these valves.

This report found that PG&E has considered the implications to its SCADA system by incorporating the added monitoring and control capabilities required in a highly expanded automated valve program.

Studies have determined that gas evacuation time for a specific full pipeline breach or rupture can be calculated once the section of pipe is isolated. Requiring PG&E to be able to readily calculate and be able to convey this information to the first responder s, in order to allow emergency personnel to be able to make better informed site pr otection decisions, would be a prudent step for the CPUC to consider.

Our recommendations related to the Gas Transmission Valve Automation Program include:

6.4.1 PG&E should further define the benefits of the proposed Valve Automation Program in the conte xt of risk avoidance vs. cost and in comparison with other leading industry practices. PG&E should take into consideration that this program may exceed industry practices, but may represent a program that is lacking in the industry to provide a higher justification for the program and its cost.

6.4.2 PG&E should further research high false close rates experienced with ASVs; and define the potential implications as it applies to the contemplated expanded use in their transmission system.

6.4.3 PG&E should annually review the state of technology on ASV valve error rates and determine if there is a compelling case to change operation of RSVs to ASV mode.

6.4.4 In the event of a full pipeline breach or rupture and once the section of pipe is isolated, PG&E should be able to quickly determine the gas evacuation time and be able to convey this information to the first responder s to enable better site protection decisions.

Pipeline Records Integration Program

The program consists of two work efforts: first, Maximum Allowable Operating Pressure (MAOP) Validation and second, Gas Transmission Asset Management (GTAM). MAOP Validation involves collecting and verifying the pipeline strength tests and pipeline features data necessary to validate and re -calculate the MA OP for PG&E's gas transmission pipelines and pipeline system components. While GTAM involves the specific work efforts related to Information, Technology required to support the MAOP validation work effort in terms of the data definition, collection, stora ge, and retrieval capabilities that jointly meet the requirements for traceable, verifiable, and complete information related to PG&E's gas transmission infrastructure and to support operational efficiencies. In order to address the records management requirements PG&E will need to improved access to detailed information about all the components and pipe installed on PG&E's gas transmission system . The Company is not using the existing geographic information system (GIS) as a source for information at this point. To determine MAOP, PG&E is validating specifications, design documents, and complete pressure test records. PG&E plans to utilize an industry standard indexing process known as "linear referencing" to link physical attributes stored in the GIS wi th tabular asset information stored in SAP. Further, in order to continue to populate the asset system with current information, PG&E is planning to deploy over 800 mobile computing devices to facilitate consistent and accurate data collection. The existi ng GIS database will be compared and combined with the new information at some point in the future.

The GTAM effort involves the consolidation of various important pipeline records into two primary electronic systems, which will enable PG&E to integrate pipeline records going forward.

The GTAM project has four primary objectives, tracking all asset data, tracking all materials used, capturing operation and maintenance work management data and the ability to integrate all asset related information. The GT AM project will be executed in four phases (phase 0 through phase 3) over a period of approximately 3.5 years.

This report found that PG&E's plan to have data resident in native applications and linked minimizes data hand -offs and potential errors. PG&E h as defined several feedback mechanisms to provide plan amendments as needed as the MAOP and GTAM processes yield new information.

However, we noted the absence of any mechanisms aimed at dealing with data errors discovered within the existing GIS through comparison with GTAM data . Since these potential errors may not be discovered until well after the decision tree process has identified at risk segments, comparison of existing GIS data with GTAM data needs to be initiated early in the process and needs to continue to occur on a preset frequency.

This report also found that some of the information in the existing GIS system is not sufficiently detailed enough to permit analysis of MAOP and other data attributes. Consequently, to some extent expenses, associated with populating the original GIS, are likely to be incurred again.

It appears that PG&E has developed a GTAM and MAOP cost forecast using best available information and practices, but estimates, being Class 4, still contain a high level of uncertainty. Consequently, we believe it appropriate that PG&E revisit its cost estimates annually based on its progress and new knowledge gained through the data examination.

Our recommendations related to the Pipeline Records Implementation Program include:

7.4.1 PG&E has admitted that some of the information in the existing GIS system is not sufficiently detailed to permit analysis of MAOP and other data attributes. Consequently, to some extent the expense associated with originally populating the GIS will need to be duplicated. Since PG&E's existing GIS and Pipeline Records Program cannot be relied upon as a comprehensive and accurate source of gas transmission information, cost concessions in the Pipeline Records Integration Program should be considered to compensate for duplicative efforts.

7.4.2 Implement a feedback mechanism to ensure that errors discovered within the existing GIS data through comparisons with GTAM data are handled expeditiously particularly any that would result in a segment's MAOP prior certification to be in question.

7.4.3 PG&E should revisit its cost estimates at least annually and recalculate balance of project capital and expense requirements based on project progress and new knowledge gained through the data examination. The CPUC should be provided with a report in a format specified by the CPUC, with input from CPSD.

Implementation Plan Management Approach and Estimate Risk Quantification

Implementation Plan Management Approach

Some 273 cities in PG&E's service area will be impacted by the Implementation Plan. In a program of this size, complexity and duration, it has become a prudent practice for gas operators to establish a Program Management Office (PMO). The key objectives of the PMO are to monitor and assure the proper delivery of the defined scope of work, safety, quality, cost, and schedule. The major functions of PG&E's program management organization are Project Sponsor, Executive Steering Committee, Program Manager and PMO. Within the PMO are the following functions: program management, project controls, project support, quality assurance/quality control and Project management support. PG&E plans to retain Parsons, to initially help to implement its P SEP and teach PG&E the project management organization structure. Contingent on appropriate personnel being trained by working with Parsons, PG&E expects to manage the PMO with its own staff over a 12 to 18 month period.

Cost and Contingencies Estimate

It is generally recognized that budget level estimates are a combination of science and art, relying on historical data and experience. Care must be taken not to include estimating allowances in the baseline cost to address increased likelihood of unfore seeable conditions. These costs are captured in the contingencies estimate. When indicating a contingency estimate, a confidence level is referenced. Factors considered in choosing a confidence level should be based on such factors as risk assumptions, project complexity, project size, and project criticality.

PG&E used a quantitative risk assessment approach to estimate contingencies using stochastic modeling and analysis, a well-accepted industry practice. The Company has stated that th e approach used to estimate allowance and risk -based contingency is consistent with the approach included in other PG&E applications previously approved by the Commission.

This report b elieves establishing a PMO for a project of this size is appropriate and finds both the governance and control functions are consistent with industry practices. The organization structure itself appears lean with several key positions yet to be defined. At the time the Implementation Plan was submitted, PG&E was developing a detailed set of program processes, controls and management tools. Typically, these tools are referred to as program execution plan or program management plan.

We believe the baseline cost estimate development and approach to estimate contingencies is based on well e stablished cost estimating practices . PG&E has adopted a 90% confidence level, which results in a PMO total cost contingency of $6.1 million or 17.5% of the total baseline cost. The total contingency on the PSET is $380.5 million or 21.1% of the total base line cost. However, f rom the information reviewed , there d oes not appear to be a project mitigation strategy that addresses risks covered by the program's contingency nor does it appear that PG&E has established a reporting mechanism to the CPUC. In additi on, g iven the repetitiveness of certain PSEP activities, such as valve replacement , it is not clear whether a repetitive learning curve is included the quantitative risk assessment approach. Consequently, we believe this model should be periodically updated and at least annually, a copy should be provided to the CPUC.

Overall, the Implementation Plan schedule is achievable, but aggressive. The aggressive schedule results in additional risk that the total estimated cost of the Program may exceed estimates.

Our recommendations related to the Implementation Plan Management Approach and Estimate Risk Quantification:

8.4.1 PG&E should be required to provide a copy of its PMO project execution/ management plan for the PSEP in a format specified by the CPUC.

8.4.2 PG&E should report to the CPUC monthly the forecast and actual contingency draw down in a format specified by the CPUC.

8.4.3. PG&E should update and run the quantitative risk assessment (QRA) model annually and provide a report in a format specified by CPUC.

8.4.4 Given the general recognition that the PSEP schedule is aggressive, PG&E should undertake the development of schedule contingency estimates based on the current Program completion goal as well as the schedule contingency estimates if the program duration were to be extended by 6 months or by 12 months.

8.4.5 There are numerous risks identified in connection with implementing the PSEP, PG&E should develop a risk mitigation matrix describing significant risks, their potential financial impact, m anagement's mitigation strategy and the individual charged with responsibility to continually track and determine the effectiveness of this strategy.

2.0 Background

On September 9, 2010, a 30-inch diameter natural gas transmission pipeline, owned and operated by Pacific Gas and Electric Company (PG&E or Company), ruptured in the city of San Bruno, California, killing eight people, injuring many others, and causing significant property damage. The information gathered, because of the National Transportation Safety Board's (NTSB) investigation, concluded that the rupture was initiated at the long seam of a small pipeline segment.

This incident, along with a number of other pipeline incidents this past year, has caused the natural gas pipeline industry and those who regulate it, including the California Public Utilities Commission (CPUC or Commission), to reassess existing pipeline safety standards and best practices. Specifically, the Commission issued on February 25, 2011, an Order Instituting Rulemaking (OIR) 11-02-019 to adopt its own Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Rate Making Mechanisms. The rulemaking was intended "to establish a new model of natural gas pipeline safety regulation" in California. Then on June 9, 2011, the Commission issued D.11-06-017, requiring Southwest Gas Corporation, Southern California Gas Company, San Diego Gas and Electric Company, and PG&E to file a Natural Gas Transmission Pipeline Replacement Pressure Testing Implementation Plan, referred to within this report as the Pipeline Safety Enhancement Plan (PSEP) or Implementation Plan. The Commission's goal of the Implementation Plan was to cost-effectively replace or test, in an orderly manner, all gas transmission pipelines that had not been sufficiently pressure tested.

On August 26, 2011, PG&E submitted its Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan. The PG&E Implementation Plan (also referred to as PSEP) is a multiphase, multiyear program developed to comply with the CPUC decision. PG&E states that the work contained in its PSEP is in addition to its existing pipeline replacement and maintenance, risk mitigation, and integrity management programs.

The four main components to PG&E's PSEP are as follows:

1. Gas transmission pipeline modernization - a known safety margin will be established for every gas transmission pipeline segment and each segment will be verified through strength testing requirements, or replaced. Also, pipelines will be retrofitted to accommodate the use of in-line inspection tools.
2. Valve automation - automated valves will be installed in highly populated areas and where active seismic faults exist. Utilizing an upgraded Supervisory Control and Data Acquisition (SCADA) and automatic shutoff valves, PG&E will be able to remotely or automatically shutoff the flow of gas in the event of a pipeline rupture.

3. Pipeline records integration - collection and verification of all pipeline strength tests and pipeline features data will be gathered and analyzed to calculate the Maximum Allowable Operating Pressure (MAOP) . A new electronic data management system will be developed.
4. Interim safety enhancement measures - prior to testing or replacement PG&E will validate the MAOP , expand its practice of reducing pressure on certain pipelines and increase the number of patrols and leak surveys.

To support the pipeline modernization component of the Plan, PG&E will conduct extensive customer and community outreach regarding outage s and potential public disruptions. The Company will also employ a program management office to provide oversight, control costs, and maintain a high level of quality. The implementation plan also provides a regulatory scheme to recover costs required for Plan implementation. PG&E is not seeking cost recovery for its 2011 Implementation Plan expenditures.

Under the Implementation Plan, the work is divided into two phases:

- Phase 1 - includes all non-pressure tested urban pipelines operating at greater than 30% system minimum yield strength (SMYS) and pipe with known manufacturing related threats operating at less than 30% SMYS. Phase 1 was initiated in 2011 and is planned to be completed by 2014.
- Phase 2 - includes all non-pressure tested urban pipe operating at less than 30% SMYS, previously pressure-tested pipe, and all Class I non-HCA rule pipelines. Phase 2 is to be implemented in 2015 and continued until all 5,786 miles of natural gas transmission pipelines have been addressed.

3.0 Objective

The objective of the study was to review PG&E's Implementation Plan and determine if it is an appropriate response to D. 11-06-017. The Commission's decision contains 13 specific orders, the first three of which deal with related issues, but are not specific Implementation Plan requirements. The remaining 10 orders deal with various aspects of the Implementation Plan. A condensed version of these 10 orders follows:

- By August 26, 2011, a proposed Implementation Plan must be filed to comply with the requirement that all in-service transmission pipelines have been pressure tested in accordance with 49 CFR 192. 619, excluding 49 CFR 192. 619 (c).
- Must include a timetable for completion and interim safety enhancement measures for pipelines that must run at, near Maximum Allowable Operating Pressure, or above 30% System Minimum Yield Stress.
- State the criteria on which pipeline segments are identified for replacement rather than pressure testing.
- Contain a priority-ranked schedule for pressure-testing pipeline not previously tested and certain Maximum Allowable Operating Pressure reductions.
- Must consider retrofitting pipeline to allow for in-line inspection tools and shutoff valves.
- Must include best available expense and capital cost projections by component for each year of the Implementation Plan.
- Recommend a rate proposal for the Implementation Plan with cost sharing between shareholder and ratepayer.
- Conduct workshops concerning the technical aspects of gas pipelines that have not been pressure tested. Representatives from Consumer Protection and Safety Division are to be included as active workshop participants.

4.0 Scope and Approach

4.1 Scope

In connection with Commission orders in D. 11-06-017, Jacobs Consultancy was asked to review certain aspects of PG&E's Implementation Plan. Specifically, Jacobs was requested to assess the Pipeline Modernization Implementation Plan Decision Trees, prioritization for pressure testing, use of remote control valves and automatic shutoff valves, the pipeline records integration program, and the Implementation Plan management approach. In addition, we were asked to comment at a high level on the overall reasonableness of PG&E's projected costs.

4.2 Approach

Our approach to reviewing PG&E's Pipeline Safety Enhancement Plan consisted of collecting, rationalizing, and performing an analysis of various aspects of their Implementation Plan. Having supported the Independent Review Panel in its assessment of the San Bruno incident, we were able to readily apply that background and knowledge, providing both context and perspective regarding PG&E's Implementation Plan. We requested data and received responsive information from PG&E and we conducted a number of interviews with PG&E staff who authored, or are directly involved in executing the Pipeline Safety Enhancement Plan. In addition, we collaborated with the CPUC staff who participated in interviews, technical reviews and final report editing.

Since the Implementation Plan's key objective is to "establish a new model for pipeline safety regulation", there is no standard for direct comparison. Therefore, in formulating our opinion, Jacobs primarily relied on the D.11-06-017 orders for stipulated requirements, its knowledge of existing industry standards and regulations, and expert judgment within the industry.

5.0 Gas Transmission Pipeline Modernization

5.1 Discussion

In this section, we examine:

1. The approach and structure of the decision trees PG&E used to determine the actions required to meet the requirements of D.11-06-017.
2. The methodology for prioritization flowing from the results of the decision tree process.

Our findings, conclusions and recommendations are based on a review of Pacific Gas and Electric Company's (PG&E) Pipeline Safety Enhancement Plan, Chapter 3 - Gas Transmission Pipeline Modernization Program and supporting attachments. The information contained in the documents reviewed, was augmented by an interview with Todd Hogenson and Jerrod Meier conducted on December 7, 2011. Also in attendance at the interview from PG&E were Chuck Marre, Bill Mullein, Kerry Klien and Dan Menegus.

5.1.1 Decision Tree Methodology

In order to define work to be accomplished under Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan, referred to as the Pipeline Safety Enhancement Plan (PS EP) or Implementation Plan, PG&E developed decision trees using a deterministic threat model based on applicable pipe threats . The Decision Tree was developed to evaluate all 5,786 miles of PG&E's transmission pipeline for five relevant threat categories grouped into three individual decision tree queries: Manufacturing T hreats, Fa brication and Construction Threats and Corrosion and Latent Mechanical Damage Threats.

The decision tree takes its inputs from the existing ESRI -based geographic information s ystem (GIS). The first level of filtering limits inputs to pipelines operating at over 60 PSIG. The second initial filtering identifies if the pipeline meets transmission criteria based on US Department of Transportation (USDOT) criteria[1]. The third fil ter identifies pipeline that has MAOP established based on verifiable calculations or strength testing records. All remaining pipelines are subject to the decision tree for evaluation and eventual prioritization.

As a means of grouping, phasing and prio ritizing pipe sections, PG&E uses pipe threats to determine a work prioritization system based on pipe segment properties both known and unknown. The decision tree also used the individual pipe characteristics such as type of steel, operating pressure, land use, proximity to people, and threat. PG&E has developed the decision tree to help identify phases of work, and to provide an assessment method for mitigation for five

[1] Appendix A of PG&E Risk Management Procedure 6 titled *Gas Transmission Integrity Management Program* (RMP-06).

of the nine threat categories as described in ASME publication B31.8S, Appendix A and incorporated into 49 CFR, Subpart O. The five threat categories are:

1. External corrosion
2. Internal corrosion
3. Manufacturing-related defects
4. Fabrication/ construction-related threats
5. Latent third-party and mechanical damage threats

PG&E intends to handle the remaining threats of Stress Corrosion Cracking, Equipment Failure, Incorrect Operations – Human Error , Weather-Related and Outside Force are through its existing Transmission Integrity Management Program, Pipeline Risk Management Program and operations/maintenance procedures and standards. The five threat categories were further grouped by Manufacturing Threat, Fabrication and Construction Threat and Corrosion/Latent Mechanical Damage Threats , in order to derive the three individual decision trees that PG&E then used to query its existing GIS.

PG&E uses the decision tree to query the Company's existing GIS pipe information to define and categorize pipe segments in a sequential decision process against the three threat groups. This allows PG&E to assess and compare different parts of its transmission system on the basis of threats and group them accordingly. PG&E used industry studies, publications and experts as well as PG&E operational history to develop thresholds for querying the GIS data.

The Decision Tree that addresses pipeline manufacturing related threats is for pre-1970 pipe. This date was selected to reflect improvements in several areas:

- Changes in pipe metallurgy
- Plate welding to form pipe (longitudinal welds)
- Increase of pipe mill test pressures and other pipe inspection criteria combined to minimize the threats associated with imperfections introduced in the pipe manufacturing process.
- Establishment of minimum pipeline manufacturing, design, construction, testing, and maintenance and operation safety standards for all pipeline operators by Publication in 1971 of federal natural gas transportation pipeline safety regulations, 49 CFR Part 192.
- Pre-1970 pipe with a manufactured long seam performed using low frequency Electric Resistance Weld (LF-ERW), spiral weld, Single Submerged Arc Weld (SSAW), A.O. Smith flash weld, lap weld, hammer weld, or any pipe with a longitudinal joint efficiency factor less than one is considered a manufacturing threat.

To reduce this threat, system pipe that has not been strength tested to 49 CFR 192, Subpart J, operates at or greater than 30 percent of SMYS and is located in a populated area will be replaced. Pipe that operates below 30 percent of SMYS in a populated area will be strength tested and rural area piping will be checked for fatigue cracks in Phase 1 and strength tested in Phase 2.

The Decision Tree that addresses pipeline threats from fabrication and construction has a threshold date of 1960 intended to reflect fabrication and construction improvements that resulted from:

- Publication and industry use of ASME B31.8 s, formally known as ASA B31.8, published in 1955 and 1958
- CPUC's enactment of GO 112 in 1961
- Widespread use by 1960 of Shielded Metal Arc Welding for gas transmission
- Improved construction and quality control practices

Criteria will be developed to determine if pre-1960 vintage anomalous wrinkle bends and excessive pups, vintage miter bend greater than three degrees, compression joints and non-standard fittings are to be replaced as they are found or be subjected to a formal Engineering Condition Assessment (ECA).

Pipe joined by welding practices that could result in workmanship flaws or poor metallurgical properties, or weld joint designs such as bell-bell-chill rings and bell-and-spigot, and operating above 30 percent of SMYS will be removed from service or strength tested and in-line inspected.

Internal and external corrosion and latent third-party or mechanical damage refers to damage that is unknown to PG&E because in the case of corrosion, it is not visible and not known until it results in a leak or other failure. In the case of third-party damage, it is often unknown as the party that caused the damage was either unaware that the damage occurred or chose not to report that the damage occurred. This decision tree cannot "test" for these risks, but it does specify testing, in-line inspection (ILI) or close interval survey (CIS) actions, which can help in identifying the risk related damage, in one of the project phases depending on the pipeline segment attributes including stress and HCA parameters.

The Assessment methods for this threat group include:

- Strength testing
- Wall loss detection technologies (ILI)
- Remaining strength calculations

- Close interval survey (CIS) and direct current variance gradient (DCVG) technologies will be used to detect locations where active external corrosion may be occurring or coating damage has occurred.

Where these assessments are either not feasible or cost effective, then the pipe is intended to be replaced.

The decision tree will be used to validate and ensure the margin of safety for the pipeline system. The methods to validate margins of safety include:

- Pipeline replacement
- Strength testing
- Fitting replacement

While the methods to ensure margin of safety is preserved include:
- In-Line Inspection
- External or Internal Corrosion Direct Assessment
- Non-Destructive Testing or Other Testing Method

5.1.2 Prioritization Process

This section addresses the prioritization process and examines its consistency with and support by the decision tree, if scheduling is appropriate, solutions for any prioritization changes and what projects could be deferred or not done.

Work prioritization begins with the decision tree that provides a phased high-level priority based on three threat group categories. The work is further prioritized by work type:
- Pipe replacement
- Strength test
- ILI

This is complemented by consideration of:
- Population density of a pipe segment
- Highest potential impact radius (PIR) per project segment
- Margin of safety

A factored prioritization system that is hierarchically based is used to develop an annual schedule. The factors considered are all grouped from the highest to lowest:
- Descending order of class location: Class 4 (highest population density) to Class 1 (lowest population density)
- Decreasing PIR broken out into four Tier Groups

- Percentage of high consequence area (HCA) pipe within each project

During Phase 1, which is currently underway, PG&E plans to complete approximately 350 projects. This necessitated developing a structured plan for scheduling and execution. During the scheduling process, the following were considered:

1. Projects in order of descending margin of safety for the pipeline, considering interim safety enhancement measures and normal operating conditions.
2. Evaluating the interactive nature of the threats. A single threat category may not pose a significant threat to the pipeline segment, but multiple threats can contribute to a compounding effect, which may elevate the priority of any remedial measures.
3. Projects that have a significant safety component where pressure reductions would require curtailments of critical gas service.
4. Projects with little or no expected permitting restrictions or delays. PG&E will make reasonable efforts to schedule and sequence work in order to maintain customer service and minimize customer impact.
5. Coordination of work with the valve automation projects and other gas transmission pipeline work and maintenance to ensure efficient use of resources and minimize overall gas system impacts.

In cases where pipeline replacement is indicated by the decision tree process, PG&E intends to perform additional analysis steps to ensure that replacement is truly needed. First, data available from the maximum allowable operating pressure (MAOP) data records validation work stream in conjunction with the Gas Transmission Asset Management project (GTAM) will be reviewed. If a pipeline features list (PFL) exists, the team will carefully review a ll the PFL data. If a PFL does not exist at that point in the timeline, the MAOP team will be asked to accelerate the review process for the segment(s) in question. If this is not feasible within the overall project plan, the team will then perform field validation prior to planning the replacement.

The prioritization process also accommodates pipeline segments with components known to have questionable data, such as taps, to a later period in the overall plan. The intent is that it is more probable that the MAOP data validation work now underway may, by then, develop better data for those elements to permit a more accurate determination of the need for replacement or testing. Once that information is available, PG&E will re -asses the priority for thos e pipeline segments.

As with any program of this size and scope there will be a need for scope shift or change as pipe segment and attribute data are eventually validated and/or corrected. As PG&E develops lessons learned about a particular pipe type, those lessons will need to be applied to update the program. Projects that may become delayed , due to significant permitting or engineering challenges, are intended to have engineering and permitting activities begin early in the Pipeline Program, since permi tting may take up to 18 to 30 months before construction can begin. Individual project scheduling may have to be revised to account for project delays that may affect the prioritization or completion of certain work. PG&E plans to update the source database and project scope on a continuous basis and to provide semi-annual reports to the CPUC. This will be used to refine the prioritization and schedule for certain projects.

5.2 Findings

- PG&E relied on outside experts along with their internal knowledge to devel op the decision tree process and model. In particular, Kiefner & Associate were contracted to develop the model and EN Engineering, which was retained to assist in the valve replacement work effort, collaborated in developing the decision tree.
- Decision Trees define the work to be done and were developed to address specific pipe threats.
- PG&E utilized industry studies and experts to help define threats and mitigation.
- PG&E developed three threat groups covering five threat categories to incorporate into the decision tree process.
  - PG&E has a multi level prioritization system that is focused on safety of pipeline segments, without documented strength tests, that are operating in populated areas.
- The schedule is intended to be developed using a highest to low est factored priority system.
- Work of other projects and programs will be coordinated during the scheduling process.
- PG&E will use lessons learned to refine the prioritization and scheduling process.
- Mitigation strategy for each threat group addresses all government regulations and safety concerns.
- The Decision Trees query the existing GIS database using a sequential decision process.
- The threat decision process begins by determining if a segment is transmission as defined by the USDOT.

5.3 Conclusion

- PG&E has reached out to industry experts to lead the development of its decision tree process and utilized other industry experts to contribute to the decision tree design. We believe this process is well defined, consistent, and that it will allow PG&E to validate threats and ensure that all decisions will be traceable and documented.
- PG&E proposes to utilize industry accepted and proven methods to establish a margin of pipeline safety.

- The prioritization and scheduling process is flexible and address es the safety aspects of the program.
- The prioritization process includes a further data validation between the existing GIS data and a detailed MAOP data validation database, under development, to minimize expenditures on pipeline replacement where not fully justified.
- Projects are scheduled to minimize the disruption of gas supply to the customer.
- It appears that all DOT Classified transmission pipe on the PG&E system will be subjected to screening in the Decision Tree process.

5.4 Recommendation

5.4.1 To ensure that PG&E is following its decision tree and prioritization process, periodically an audit of a small number of projects should be undertaken to verify the process results.

6.0 Gas Transmission Valve Automation Program

6.1 Discussion

In this section we review the approach and structure of the valve automation program, and the appropriateness of the degree of automation and proposed enhancements of the Supervisory Control and Data Acquisition system (SCADA).

Our findings, conclusions and recommendations are based o n a review of Pacific Gas and Electric Company's (PG&E or Company) Pipeline Safety Enhancement Plan, Chapter 4 - Gas Transmission Valve A utomation Program and supporting work papers. The information contained in the documents reviewed was augmented by an interview with Dan Menegus and Richard Geraghty, conducted on December 7, 2011. Also in the interview from PG&E were Chuck Marre, Bill Mullein and Kerry Klein.

The objective of the Valve Automation Program is to enable PG&E , either remotely or with local automatic control, to shut off the flow of gas quickly in response to a gas pipeline rupture that is of a magnitude capable of being detected. This program will also replace mainline valves which impedes the ability to use in -line devices to inspect for t he integrity of the transmission pipeline system. PG&E proposes to implement this program in two phases; Phase I, 2011 through 2014, is the subject of the current rate case and has identified approximately 228 isolation valves for replacement, automation o r upgrade. Phase II is intended to initiate in 2015 and will be specified as to scope, schedule and cost at a later date. This phase envisions automation of approximately an additional 330 valves

The Valve Automation Program will work in tandem with the Pipeline Modernization Program by focusing on areas where the pote ntial consequences are greatest. The prioritizations for the installation of automated valves on pipeline segments are based on:

1. Population density (i.e., class location, presence of high consequence areas (HCA).
2. Potential Impact Radius (PIR) of the pipeline.
3. Criteria for earthquake fault crossings.

The second focus of the program is to provide suitable enhancements to the SCADA system to provide the information and tools to assist PG&E's operators in its Gas Control Center to better identify sections of pipeline which require isolation and more quickly respond in taking the actions if, and when, necessary. .

This program will significantly expand the Company's use of automated isolation valves. PG&E's program intends to use two types of automated valves:

1. Remote Control Valves (RCV) which shut -off gas flow after being remotely operated from the Gas Control Center.
2. Automatic Shut -off Valves (ASV) which have controls at the valve site that operate automatically (without Gas Control Center intervention) to shut -off gas flow (primarily to be used in areas of earthquake faults).

To evaluate the placement and type of valve to be used in a given circumstance PG&E contracted EN Engineering (ENE)[2] to assess and determine industry trends . During the engineering company's independent review, the following tasks were performed:

- Review industry literature on the topics of ASVs and RCVs.
- Conduct an assessment of transmission pipeline operators to determine the extent to which ASV and RCV equipment is utilized.
- Review and provide information on the use of ASV and RCV equipment on natural gas transmission pipelines.

ENE contacted twenty-five interstate, intrastate and local distribution companies with gas transmission pipelines . Twelve companies responded to a brief questionnaire , the mix of responding companies were:

- six interstate
- one intrastate
- two interstate/intrastate
- two intrastate/LDC
- one LDC

These twelve companies operate a total of 68,0 00 miles of transmission pipeline with individual companies operating as few as 200 miles to as many as 25,000 miles. PG&E states that the companies, which responded, expressed a strong preference to use RCVs over ASVs . A primary concern with the use of R CVs is the dependence on communication and power in order to operate the valve. While ASVs have the advantage of rapid response, more than 85% of the survey respondents with ASVs installed on their system had experienced false closures. Most respondents rely upon the requirements of 49 CFR §192.179 for determination of valve spacing.

For future flexibility, PG&E plans to install valves that can be configured to operate in either RCV or ASV mode. The Company plans to primarily configure the valves in RCV mode in

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[2] ENE is ISO 9001:2008 Quality Management Systems qualified and their professional staff average more than 25 years of experience. The staff for the PG&E project consisted of Mr. Ahdrejasick a PE in Ill, with 27 years experience who previously worked in senior management at Peoples Gas , Mr. Armstrong who has 42 years experiences, and also worked in senior management at Peoples Gas, Ms. Hudson a PE in Ill with 10 years experience and Ms. Sus with 10 years experience

highly populated areas and ASV mode in highly populated areas were pipelines crosse active earthquake faults and the fault poses a significant threat to the pipeline.

6.1.1 Decision Trees

PG&E developed two decision trees for identifying segments for valve automation to respond to population density and earthquake fault crossings. As a starting point for its determination process, PG&E used US Department of Transportation (USDOT) defined gas transmission pipeline segments (i.e., those operating at s tress level s of 20 percent or more of Specified Minimum Yield Strength (SMYS)) within Class 3 and 4 areas that exceed minimum threshold criteria for pipe size and operating pressure , as defined using a PIR calculation. PG&E also includes all 16-inch and la rger pipelines operating at a pressure above 240 pounds per square inch gauge (PSIG), operating in this process. Minimum threshold criteria are reduced to recognize the higher potential consequence for higher populated areas such as Class 3 HCA and Class 4 areas. PG&E had ENE review that its criteria was sound from an engineering and pipeline safety viewpoint. The decision trees process was a key tool in identifying pipeline segments that require automated valves; however, PG&E states this process is always augmented with practical engineering judgment.

The Population Density Decision Tree is utilized to identify all Phase 1 and Phase 2 pipe segments that will be automated.. The criteria embodied in the model include:

- Class 3 with a PIR greater than 200’
- Class 3 with more than 50% of segment classified HCA and with PIR greater than 150’
- Class 4 with PIR greater than 100’[3]

For the Earthquake Fault Crossing Decision Tree , PG&E will install automated pipeline isolation capability on all pipeline earthquake fault crossings in Class 3 and 4 areas, and Class 1 and 2 HCA areas where:

- The pipe has a PIR value of > 150 feet.
- The earthquake faults are considered to be active.
- The pipe has greater than a low threat of rupture under maximum anticipated magnitude event conditions.

Within the Earthquake Fault Crossing Decision Tree there are two alternatives. Where fault crossings were deemed a significant or high threat to the pi peline, ASVs will be installed and where only a low threat exists, the fault crossin g will be able to be isolated with RCVs installed at the same general spacing as for valves equipped with RCVs in the Population Density Decision Tree.

6.1.2 Valve Spacing Determination

While 49 CFR, Section 192.179(a), provides guidance for the installation of isolation valves, it does not specifically address spacing applicable to automated valves. However, PG&E used this regulation as a starting point for maximum spacing since it was developed taking into account typical operational impacts of pipelines in various class locations.

The code requires[4]:
Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

1. Each point on the pipeline in a Class 4 location must be within 2 1/2 miles (4 kilometers) of a valve.
2. Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.
3. Each point on the pipeline in a Class 2 location must be within 7 1/2 miles (12 kilometers) of a valve.
4. Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

PG&E had ENE analyze how varying valve spacing impacts the time required to evacuate the gas through a break in the pipe after a the section of pipe was isolated. The study determined that if valve spacing was limited to Class 3 requirements of 8 miles, the impact on gas evacuation time was increased approximately two minutes when compared to five mile spacing. PG&E decided to use an approximate spacing of 8 miles for Class 3 locations and to stay aligned with the code guidance to utilize approximate five mile spacing in Class 4 areas. These maximum distances may be slightly exceeded by PG&E in order to allow a valve to be installed in a more accessible or lower public impact area.

6.1.3 SCADA System Enhancements

PG&E will deploy systems and technologies that fully leverage valve automation to provide early warning of events, while preventing false valve closures. Gas Control operators will be given training, tools and information to allow for quicker detection and response to pipeline ruptures. To accomplish this PG&E will include:[5]

1. Additional SCADA monitoring points for pressures and flows to enhance understanding of pipeline dynamics.

[3] All PG&E Class 4 pipe segments classified as gas transmission have a PIR value greater than 100 feet, therefore all Class 4 pipe segments are identified for automation.
[4] PACIFIC GAS AND ELECTRIC COMPANY CHAPTER 4 GAS TRANSMISSION VALVE AUTOMATION PROGRAM Page 4-22
[5] PACIFIC GAS AND ELECTRIC COMPANY CHAPTER 4 GAS TRANSMISSION VALVE AUTOMATION PROGRAM

2. Detailed SCADA viewing tools that provide a comprehensive understanding of individual pipeline conditions in real-time and the potential effects (e.g., downstream pressures and flows) if a pipe line segment is isolated, as well as provide increased understanding of pipeline configuration and constraints.
3. Specific pipeline segment shutdown protocols to provide clear instructions on actions to be taken to quickly and effectively isolate a segment.
4. Situational awareness tools, which utilize advanced composite alarming, and best practice alarm management methodology to highlight issues requiring immediate gas operator action.
5. Interactive tools that will allow gas operators to quickly access GIS physical pipeline information in relationship to SCADA points, and to geographically locate SCADA points.
6. Training simulation tools to prepare gas operators for potential pipeline rupture scenarios.

PG&E will use the Independent Review Panel (IRP) Report's suggestion and have an external party review the SCADA system to ensure effective execution of these actions, and to identify additional improvement opportunities.

6.1.4 Scope of SCADA Enhancements

When a leak or rupture occurs there are two steps that need to be taken to determine the overall response time required to isolate and depressurize a pipeline segment. The two steps are:

1. Leak or rupture has to be detected.
2. Decision has to be made to isolate a pipeline segment.

The SCADA enhancements address these steps and fall into three categories.

1. Additional information relating to pressure, flows and other critical gas system data will be provided by the SCADA system. This information will enhance controllers' knowledge of gas system conditions and support early detection, better understanding and pinpointing of a significant breach in the integrity of the line.

    - Providing pressure measurement upstream and downstream of all automated valves, and additional flow monitoring at key sites along the automated pipeline sections. This would result in available pressure data at approximately 5-8 mile spacing along the pipeline, and flow data at approximately 15-20 mile spacing along the pipeline and at major crossties to interconnected pipelines.
    - Additional SCADA screens with detailed information regarding the pipeline system including pressure, flow, rate of pressure and flow change, current system configuration, connected major customers and loads, and key system operational requirements.

- Additional information on man ual valve positions with a specific focus on valves affecting gas routing. This will likely be accomplished by a combination of adding SCADA points for valve position of select manual valves and providing an electronic "pin map" tool[6] for valve positions not communicated via SCADA.
- Building advanced applications for the new data historian being implemented in 2011 as part of an enterprise wide Information Technology project and in conjunction with Control Room Management (CRM). These advanced applications would integrate real -time data with other disparate data and turn it into actionable information by gas operators.
- Integrating GIS and SCADA data historian providing Gas Operators with access to physical pipeline information and geographical reference for SCADA data points.

2. Additional training for operators in detection of events and proper response to specific events.

    - Development of specific line rupture training exercises involving the use of ASVs and RCVs using the training modeling software purchased by the CRM initiative.
    - Creation of specific job aids, pipeline shutdown plans and protocols to facilitate identification of line breaks and provide direction to the operator on proper response.

3. Advanced SCADA logic, tools and technologies that identi fy abnormalities and bring them to the attention of the operator.

    - Advanced composite alarm logic and filtering that performs calculations involving multi-site data to identify specific types of emergency action situations.
    - Evaluation and potential imple mentation of an on -line simulator that would perform sophisticated transient flow simulation for the pipeline system to alert the controller to potential abnormal or emergency operating conditions on the pipeline, such as a large leak or partial line break, and notify the operator.
    - Evaluation and potential implementation of various detection technologies connected to the SCADA system, such as leak, pipeline damage and ground movement, that could provide proactive identification of developing risks.
    - Evaluation of redundant communications between field valve automation sites and the Gas Control Center, and the available communication technologies available to accomplish this redundancy. PG&E's gas SCADA system typical communication methods of dedicated lease lines and PG&E owned RF MAS radio system are expected to have a very high level of availability after an

[6] SCADA screens that allow for the manual input of the open or closed position of valves

earthquake, but redundant communications would provide backup assurance during an earthquake or for other circumstances that could cause a potential single cause communications failure.

6.1.5 Operation and Maintenance Additions

For every new automated valve , pressure-sensing device and flow meter that will be installed there will be additional maintenance above and beyond what is required for a manual valve. This is a result of the additional communications, instrumentation, and controls equipment required by the automation. Additional maintenance required with an automated valve includes:

- Performing calibration and accuracy verification for the pressure transmitters.
- Performing inspection and testing of the SCADA remote terminal unit (RTU) for communicating with the valve.
- Performing annual inspection of the instrumentation and control equipment used in valve automation and control including the valve actuat or, valve position switches, sole noid valves, local control panel and other auxiliary equipment associated with valve control.
- Performing full end-to-end operability testing of the remote controls for automated isolation valves . This is a new requirement t hat will apply to all existing and new automated isolation valves.
- Providing training for technicians on the new equipment and on annual segment shutdowns.
- Maintenance of RTU sites
- Increased Gas Control facilities and staffing

6.1.6 ENE's Review of the Proposed Valve Automation Program

As previously noted, PG&E used the services of ENE to perform a review of its intended use of ASVs and RCVs within its proposed Valve Automation Program. Highlights from ENE's report[7] follow:

- PG&E's proposed Valve Automation P rogram exceeds current pipeline industry regulations.
- Currently, there are no prescriptive requirements in the prevailing pipeline code, Title 49 CFR Part 192, which require operators to install automated valves.
- Concurs with the Valve Automation Program 's focus on the potential benefits to the public and emergency responders, particularly those related to minimizing property damage, which can be achieved by a quick isolation of the natural gas fuel source.
- Concludes that PG&E 's Valve Automation Program will enhance public safety in areas with a long lead time for emergency response or during catastrophic outside force events such as earthquakes.

[7] 012 - Attachment4B - GasPipelineSafetyOIR_Test_PGE_20110826_216568.pdf

- Once PG&E installs the automated valves, it is the opinion of ENE that PG&E will have an industry-leading Valve automation program.
- Does not recommend any additional elements for inclusion in the Valve Automation Program.
- Recommends that the Commission should approve the Valve Automation Program.

6.2 Findings

- PG&E relied on outside experts along with their interna l knowledge to develop the decision tree process and model. In particular, ENE, which was retained to assist in the valve replacement work effort, collaborated in developing the decision tree.
- PG&E will initiate a comprehensive review and investigation of its SCADA system and may adjust the previously described plans based upon the outcome of the study.
- Decision Trees define valve automation recommendations based population density and earthquake fault crossings, but these decisions are moderated by pract ical engineering judgment.
- PG&E's proposed valve automation program exceeds current industry regulations and practices.
- By retrofitting the valve automation program to existing pipelines, PG&E'S proposal exceeds recently passed House and Senate legislation, currently under consideration by the Federal Government.
- ENE survey found that survey respondents had a strong preference to use RCVs over ASVs because of false closures.
- The population decision tree has a logical block for PIR under Class 4 pipe, but PG&E classifies all Class 4 pipe with a PIR of greater than 100, rendering this logic block ineffective.
- Various studies conducted by ENE and the Company determined that gas evacuation time for a specific full pipeline breach or rupture can be readily calculated once the section of pipe is isolated.

6.3 Conclusions

- PG&E has reached out to industry experts to lead the development of the decision tree process and utilized other industry experts to contribute to the decision tree design.
- PG&E proposes to exceed industry accepted and proven methods to establish a margin of pipeline safety.
- PG&E has considered the implications to its SCADA system to incorporate the added monitoring and control capabilities required in a highly expanded automated valve program.

- The presence of a PIR >100 logic block in the population decision tree does not impact the results of analyzing pipeline segments with the model since all PG&E Class 4 pipe PIR is considered >100.
- PG&E needs to determine in advance, and have readily available to provide to first responders, gas evacuation times, under differing scenarios (i.e., a full line breach after the last isolation valve required for isolation is shut down) for each length of pipeline that will be capable of being isolated using automated valves.
- Studies have determined that gas evacuation time for a specific full pipeline breach or rupture can be readily calculated once the section of pipe is isolated. By conveying this information to the first responder, emergency personnel would be able to make more informed site protection decisions.

6.4 Recommendations

6.4.1 PG&E should further define the benefits of the proposed Valve Automation Program in the context of risk avoidance vs. cost and in comparison with other leading industry practices. PG&E should take into consideration that this program may exceed industry practices, but may represent a program that is lacking in the industry to provide a higher justification for the program and its cost.

6.4.2 PG&E should further research high false close rates experienced with ACVs; and define the potential implications as it applies to the contemplated expanded use in their transmission system.

6.4.3 PG&E should annually review the state of technology on ASV valve error rates and determine if there is a compelling case to change operation of RSVs to ASV mode.

6.4.4 In the event of a full pipeline breach or rupture and once the section of pipe is isolated, PG&E should be able to quickly determine the gas evacuation time and be able to convey this information to the f irst responders to enable better site protection decisions.

7.0 Pipeline Records Integration Program

7.1 Discussion

PG&E's "Pipeline Records Integration Program" is a component of PG&E's Pipeline Safety Enhancement Plan (or Implementation Plan). This program will also satisfy the two Independent Review Panel (IRP) data management recommendations:

- First, PG&E committed to work with records management industry experts to conduct a thorough study of its data and records management systems and to take action to implement changes where possible. PG&E will conduct this study and will install the foundational systems and architecture to effectively manage the gas transmission systems information.
- Second, the IRP Report recommended that PG&E, upon obtaining the results of this review, undertake a multiyear program that collects, corrects, digitalizes, and effectively manages all relevant design, construction, and operating data for the gas transmission system. The Pipeline Records Integration Program will establish the infrastructure that will help PG&E address past gas transmission recordkeeping deficiencies if they are identified in the future.

The program consists of two work efforts: 1) Maximum Allowable Operating Pressure (MAOP) Validation and 2) Gas Transmission Asset Management (GTAM), as described in the following.

MAOP Validation involves collecting and verifying the pipeline strength tests and pipeline features data necessary to validate and re -calculate the MAOP for PG&E's gas transmission pipelines and pipe line system components. This does not involves utilization of the existing pipeline geographic information system (GIS) data, which is at the segment level and extending the asset information to the component level, in essence extending the granularity of the information for the pipeline system segments.

GTAM involves the specific work efforts related to Information Technology (IT) required to support the MAOP validation work effort in terms of the data definition, collection, storage, and retrieval capa bilities that jointly meet the requirements for traceable, verifiable, and complete information related to PG&E's gas transmission infrastructure and to support operational efficiencies.

7.1.1 Background

PG&E operates approximately 6,700 miles of natural gas tra nsmission and distribution pipelines, comprised of over 36,600 individual pipe segments. Documents are maintained somewhat overlapping in electronic document form and paper form. PG&E maintains its asset technical records at or among its 90 field offices and in one of two records centers. Additional electronic or hard copies are maintained at various offices or by individual work groups. The existing ESRI[8]-based GIS system is able to collect and maintain approximately 200 attributes for each pipe segment, including, for example, pipe diameter, wall thickness, pipe grade, yield strength, length, year installed, pipe coating, coating condition, joint type, joint efficiency, manufacturer, SMYS, MAOP, pressure-test date, test medium, test pressure, cathodic protection, nearby land features, land development, nearest valves, city, soil type, surface material (such as asphalt or dirt), inspection records, maintenance records, leak history, and mapping information. There are currently over three million data entries within the GIS. Financial records for the pipeline system reside in PG&E's SAP system.

7.1.2 Driving Factors

There are two primary factors that are driving the need to achieve the MAOP validation and develop the GTAM:

1. On January 3, 2011, the NTSB issued an urgent recommendation recommending that all pipeline operators validate —through records—the MAOP of all gas transmission lines located in HCAs. The recommendation included wording requiring the standard for this search should be that all information used to calculate a pipeline's MAOP should be "*traceable, verifiable, and complete*." This choice of wording adds specificity to existing gas pipeline safety recordkeeping requirements and, in the case of pipelines that had been "grandfathered" under 49 C.F.R. § 192.619(c), significantly modifies existing requirements and portrays the highest standards for records management, similar to that employed in the nuclear power and aircraft industries.
2. On January 3, 2011, the CPUC issued a letter directing PG&E to meet the safety recommendations included in the NTSB's January 3, 2011 letter. On January 14, 2011, the CPUC issued Resolution L-410 ratifying the directives of the CPUC's January 3, 2011 letter to PG&E.

7.1.3 Program Objectives

PG&E has stated the objective of the Pipeline Records Integration Program is to address the changing records management needs of PG&E's gas transmission business. PG&E's gas transmission business will need improved access to detailed information about all the components and pipe installed on PG&E's gas transmission system.
There are four important areas to be addressed:

1. Maintain reliable information by consolidating the information and functionality of the different gas transmission systems into SAP and GIS, which are PG&E's core enterprise systems (the Core Systems).

[8] ESRI is a provider of GIS and related software and services, widely used in a variety of industries. Please see www.esri.com

2. Enhance the Core Systems to enable engineering and integrity management analysis using the data maintained in the Core Systems.
3. Trace all materials used in pipeline construction, including manufacturers test results validating the characteristics of the components, from the time it is received from the manufacturer through its useful life.
4. Enable the field force to electronically access and update work orders and associated gas transmission asset data pertaining to maintenance and inspection work.

7.1.4 PG&E's Methodology and Approach

In order to meet the objective expressed above, PG&E has embarked on an approach that focuses on a deep dive into existing paper records, including structural test pressure reports, as-built drawing s, pipeline features list (PFL), etc. PG&E is reviewing the documents and building an indexed catalog into a database. There are many layers of control and quality assurance.

PG&E is not using the existing GIS (ESRI -based) as a source for information at this point. To determine MAOP, PG&E is validating specifications, design documents, and complete pressure test records. For segments where MAOP cannot be document verified, PG&E tags these segments for further evaluation as described in Section 3 above.

The data resulting from this deep dive are being assembled into a side database within the existing GIS for two purposes: first, to support the MAOP validation process and second, to comprise the detailed asset records going forward to meet the *traceable, verifiable, and complete* requirements. The existing GIS database will be compared and combined with the new information at some point in the future.

7.1.5 MAOP Validation

The MAOP Validation project involves collecting and verifying the pipeline strength tests and pipeline features data necessary to validate and re-calculate the MAOP for PG&E's gas transmission pipelines and pipeline system components. Tasks 1 and 2 below are required by Federal code and Task 3 was added to comply with CPUC directives.

1. Comprehensive search for strength test records.
2. MAOP validation of HCA[9] pipeline segments without prior strength test.
    a. Source Data
    b. Data Review
    c. PFL Build and Quality Control and Assurance
    d. MAOP Validation

[9] Currently, the CPUC defines HCA to include all Class 3 and 4 piping, as well as HCA piping near all identified sites (as that term is defined in 49 CFR, Part 192, §192.903).

3. MAOP validation of all remaining pipelines in PG&E's Gas Transmission System.

7.1.6 GTAM

The GTAM effort involves the consolidation of various important pipeline records into two primary electronic systems (SAP and PG&E's Geographic Information System), which will enable PG&E to integrate pipeline records going forward. PG&E's current underlying technology infrastructure is fragmented and consists of many proprietary systems that each contains different types of data pertaining to different types of gas transmission assets.

The GTAM Project has four primary objectives:

1. All asset data (location/connectivity, specification/features, and maintenance/ inspection history) will be tracked, managed, and stored using an industry "best practice" for characteristics, and event history at specific reference points along the entire length of gas transmission pipelines.
2. Materials (e.g., pipe and components) procured for the gas business will be tracked in a traceable chain from receipt by PG&E through the operating life of the component. Key features that would be tracked include the manufacturer, characteristics of the component, manufacturer ratings, and factory test results.
3. Work management and data capture necessary for maintenance and inspection will be significantly enhanced by the new data system. This will be accomplished by eliminating paper-based maintenance and inspection work processes and implementing automated processes to manage leak survey, mark and locate, and preventative/corrective maintenance work.
4. The project will ensure that tools are in place that enable integration of all underlying asset data (including event history such as leaks, dig-ins, etc.) to provide the full picture of pipeline asset health and condition. This will substantially upgrade PG&E's ability to perform pipeline risk and integrity analytics.

The GTAM Project consists of five key components:

1. Develop business requirements for the new systems and processes.
2. Collect, digitize, validate, and migrate pipeline data into integrated electronic information management systems, SAP, and GIS.
3. Upgrade the existing GIS system to track component-level information.
4. Upgrade the interfaces among information management systems.
5. Develop and implement mobile GTAM technology.

The GTAM project will be executed in four phases (phase 0 through phase 3) over a period of approximately 3.5 years:

1. **Phase 0:**
   a. Assess industry "best practices" related to the management of gas transmission asset data.
   b. Evaluate various gas transmission hardware, software, and data models.
   c. Assessment of current information technology architecture.
   d. Design of the target-state system architecture.
   e. Move leak reporting data from IGIS to SAP.
   f. Deploy mobile workstations to Mark and Locate and Leak Survey workers.

2. **Phase 1:**
   a. Implement a linear [10] event-based GIS data model and leverage information from the MAOP validation effort and the existing GIS system.
   b. Implement additional mobile technologies for gas maintenance and inspection and leak survey and reporting work.
   c. Integrate GIS and SAP.
   d. Implement leak -survey and reporting workflows in SAP and eliminate paper-based processes.
   e. Enable remote access to pipeline asset data and tools to record leak information in the field along with back office functionality to validate data collected in the field.
   f. Implement sophisticated gas transmission Pipeline Integrity/Risk Management tools enabling engineers to perform risk analyses across the gas transmission asset base to rank assets based on probability of failure.
   g. Deploy a foundational document management system to store and retrieve source documents to enhance traceability and data verification.
   h. Implement a single technology platform and redesign work processes to integrate material ordering, receiving, inspection, issuing, installation, and maintenance information across functions and sites.

3. **Phase 2:**
   a. Extract, convert, and import legacy pipeline, line equipment (e.g., valves) and corrosion maintenance data to a common SAP platform.
   b. Implement processes and technology to record materials installed on pipeline replacement projects.
   c. Integrate SAP and GIS systems pertaining to pipeline, line equipment, and corrosion data.

d. Implement workflows in SAP for pipeline, line equipment , and corrosion maintenance and inspections, and eliminate paper-based processes.

e. Enable mobile technology for work notifications and field completion for pipeline, line equipment, and corrosion maintenance and eliminate current paper-based processes.

f. Implement new tools to more effectively manage the gas transmission project portfolio.

g. Develop interfaces between GIS and Gas System planning software.

4. **Phase 3:**

a. Extract, convert, and import legacy station[11] asset data to a common SAP platform.

b. Integrate station asset data within the Core Systems to provide additional efficiencies and quality improvements in the way gas transmission asset data are captured, maintained, and analyzed.

c. Implement automated workflows in SAP for station asset maintenance and inspections and eliminate current paper-based processes.

d. Enable mobile applications for creating work notifications and completing field work for station asset mainten*ance and eliminate current paper-based processes.*

e. Deploy a mobile GIS system enabling workers to remotely update, correct, and "redline" asset data.

f. Implement the SAP Project Portfolio Module to manage the gas capital projects portfolio (e.g., new construction, pipeline replacement, etc.).

7.1.7 Data and Information Flow Considerations

The new GIS is also ESRI -based and is organized as PODS [12], which is an industry standard. For the deep -dive data being developed for the MAOP validation, PG&E is using a different indexing methodology called linear referencing in which each pipe component has a starting point and a length. This method , which is used by railroads, roadways, and other industries whose systems represent linear elements, provides much more flexibility than listing by segments alone. This methodology provides the ability to track pipelines at the component level in a "connected" model, indexed by a length vector. This permits a more accurate depiction of the pipeline and more accurate geo -referencing. Further, this method permits linking of related documents, such as as -built drawings, leak test reports, specification sheets, etc., that are accessible through drill -down actions within the GIS. PG&E is utilizing a product named Intrepid[13] as the interface to assemble the data and place it in the ESRI GIS using PODS. The

[10] Refers to linear referencing, a method of storing data that adds a new dimension to line features. Please see http://training.esri.com/gateway/index.cfm?fa=catalog.webCourseDetail&CourseID=1296

[11] Stations include: regulator equipment, manual and automated valves, telemetry, and ancillary equipment,

[12] http://www.pods.org/

[13] http://www.col-col-geospatial.com/

data that is being assembled is going into a separate database from the existing GIS data and is at a more granular level (pipe component vs. pipe segment).

This new GIS system wil l be linked to SAP using linear referencing as the "glue" to allow geo - referenced data to remain in the GIS and tabular data to reside in a database, such as SAP, made for that purpose. There will still be layers in the GIS for control of other physical elements.

The current GIS is being referenced to indicate that new segment information is resident in the other dataset, but no direct accuracy comparisons are being done during data collection and inputting. Once the inputs are completed, PG&E plans to us e a system called Compass that is currently in development to align the current and new database in the GIS and that will provide the ability to do additional quality control.

Document management is currently handled by a product called Documentum (this i s a company-wide system, the use of which, originated in PG&E's Nuclear Program). It is transparently linked; for example, scanned image data can be displayed in GIS and linked to Documentum for access and display.

Work management automation varies, some groups have it and some do not; for example, GSRs have vehicle-mounted devices while maintenance and construction do not and rely on paper. Planning to go to Android -based tablets for leak survey crews; these tablets will link automatically to Ventrex. T his can eliminate the need for the field workers to carry plat maps, Easytec phones, (GPS), and cameras.

Once the four phases for the GTAM project are successfully implemented, the overall system architecture will be integrated into SAP and GIS, and a num ber of PG&E's non -enterprise legacy systems (including PLM, Gas FM, IGIS, NLIS, and Gas Transmission GIS 1.0) will be retired.

7.1.8 Cost Information

PG&E developed the cost information for the two project requirements as described below and as summarized in the following table:

MAOP: Initially modeled work required. As work progresses, PG&E monitors actual costs and reflects changes back into the model. MAOP is 100% expense.

GTAM: The cost estimate started with IT templates and added in gas operations elemen ts, change management, and training requirements. GTAM is 83% capital.

PG&E developed its baseline cost estimate for each component project costs using common estimating practices for similar projects and accepted industry standards. These estimates are supported by a Basis of Estimate (BOE), setting out the assumptions upon which the estimates are based. The Total Cost Management (TCM) Framework developed by the Association for the Advancement of Cost Engineering (AACE) [14] International identifies a BOE as a required component of a cost estimate.

Based on Testimony Chapter 7, Implementation Plan Management Approach and Estimate Risk Quantification[15], a study done by PriceWaterhouseCoopers (PwC), PG&E undertook to quantify, using industry standard risk analy sis, the potential financial risk associated with the overall program. It appears that PG&E/PwC evaluated all program elements in accordance with risk modeling. It is not stated the granularity to which this analysis reached. For example, for the GTAM c apital cost risk evaluation, did the analysis reach down to the component level of software and systems needed, tablet/PC specifications for field deployment, etc.?

The program elements related to MAOP and GTAM were assigned a Class 4 AACEI score along with an expected error range [16] for each component. In our experience, software or system related projects rarely experience under -budget variances, so we would be inclined to look for budget overruns up to 30% or 40%. This is consistent with the risk asse ssment completed by PwC.

The baseline cost estimates are shown in the following table:

Figure 1 - Pipeline Records Integration Program Cost Projections

Description	2011(a)	2012	2013	2014	Total
Capital Costs (GTAM)	$7.4	$42.3	$27.2	$25.7	$102.6
Expenses (MAOP+GTAM)	55.7	88.1	32.4	7.2	183.4
GTAM	0.5	5.8	7.5	7.2	21.0
MAOP	55.2	82.2	24.9	0.0	162.3
Total Program Cost	**$63.1**	**$130.4**	**$59.6**	**$32.9**	**$286.0**
(a) The 2011 amounts will be funded by shareholders					

7.1.9 GTAM Cost Estimates

[14] AACE International Recommended Practice No. 17R -97, Cost Estimate Classification System, TCM Framework: 7.3 – Cost Estimating and Budgeting, August 12, 1997, p. 1.
[1515] 015 - Ch07 - GasPipelineSafetyOIR_Test_PGE_20110826_216571.pdf
[16] Please refer to Table 7-6 in 015 - Ch07 - GasPipelineSafetyOIR_Test_PGE_20110826_216571.pdf

Forecasts for labor, materials and equipment are generally based on PG&E's labor rates and vendor estimates for materials and equipment. Additionally, PG&E forecasts costs for other technology -specific work identified by field personnel, focused program equipment replacements, and carry-over from multi-year projects.

Labor expenses total $21 million over 4 years or about $5.3 million per year. This could represent 35 -50 FTE's to handle all or parts of: Change Management, Training, Roadmap, Preliminary Design, and Project Management.

Capital costs amount to about 83% of the overall GTAM project cost as shown below[17]

Figure 2 - GTAM Project Cost Assumptions by Cost Component

TABLE 5-6
PACIFIC GAS AND ELECTRIC COMPANY
GTAM PROJECT COST ASSUMPTION BY COST COMPONENT
($ IN MILLIONS)

Line No.	Cost Component	Forecast
1	Labor – Change Management/Training	$17.0
2	Labor – Roadmap/Preliminary Design	3.8
3	Labor – Software Development, Testing, Deployment	35.6
4	Labor – Data Conversion/Prep/Validation	32.9
5	Labor – Project Management	8.0
6	Hardware	16.2
7	Software	10.1
8	Total	$123.6

If we assume that lines 1 and 2 are PG&E labor, which corresp onds to the expense part, then the rest is hardware/software and contract labor:

- Hardware + Software = 26.3 or 21% (26% of capital)
- Contract labor = 68.5 or 55% or (67% of capital)

7.1.10 MAOP Cost Estimates

MAOP has only an expense component and the expenses a re spread over approximately 3.5 years, the largest spend is in 2012. The components of the MAOP project are shown in the table below[18].

[17] 013 - Ch05 - GasPipelineSafetyOIR_Test_PGE_20110826_216569.pdf, page 5-26
[18] 013 - Ch05 - GasPipelineSafetyOIR_Test_PGE_20110826_216569.pdf, page 5-14

Figure 3 - MAOP Validation Project Cost Assumptions by Order

TABLE 5-3
PACIFIC GAS AND ELECTRIC COMPANY
MAOP VALIDATION PROJECT COST ASSUMPTIONS BY ORDER
($ IN MILLIONS)

Line No.	Activity	Forecast Costs
1	Document Preparation (#41464520)	$54.9
2	PFL Build and MAOP Calculation (#41463067)	66.0
3	Excavations/NDE (#41489483)	7.5
4	ISTS Applications Support (#41463070, 41502220)	6.9
5	ISTS Infrastructure Support (#41463069)	3.1
6	Project Management (#41463068)	20.6
7	Project Overheads (#41463071)	3.3
8	Total	$162.3

This is a labor-intensive project and involves 300 FTE's or more from PG&E and contractors as shown in the table below.

Figure 4 - MAOP Labor by Item

Item	Cost	Personnel
Document Preparation	$54.9	98
PFL Build	$66.0	170
PM	$20.6	31

7.2 Findings

- The project is addressing two CPUC-driven mandatory requirements to ensure that MAOP ratings for all HCA pipeline segments are documented through a records search and required pressure testing. PG&E plans to go beyond those requirements and extend the project to all pipeline segments.
- Developing pipeline component data from specification sheets and historical information is a feasible approach to ensuring data integrity and efficacy, provided it is scrubbed adequately against existing segment-level information contained in the existing GIS.
- PG&E is not using the existing GIS (ESRI-based) as a source for information at this point. To determine MAOP, PG&E is validating specifications and design documents.
- PG&E is planning to utilize an industry standard indexing process called Linear Referencing, which is optimized for linear systems like roadways, pipelines, etc. This indexing system will permit cross-linking pipeline assets between the GIS physical attribute system and the SAP financial and other asset data system.

- PG&E is incorporating system consolidation and simplification through the adoption of mobile computing (computers or tablets) in the field that will replace at least three disparate types of equipment.
- Challenges or risks to these program elements include:
  - **MAOP**: Ensuring alignment and management of two separate databases.
  - **GTAM**: Change management; the project will touch at least 2,000 people and their processes. System items should be less challenging.
- The primary driver for the project(s) is safety and providing data that is reliable, accessible, and traceable (an NTSB requirement).
- Efficiencies and cost benefits have not been quantified, but are being evaluated.
- The potential labor and other savings were not a priority during development of the current rate case, but will be an element of the next rate case.
- To date, MAOP costs are running higher than original estimate but within the contingency level.
- PG&E has developed a cost forecast using its best knowledge and practices with information available today regarding the status and quality of automated systems data and paper-based data records.
- The cost estimates for the GTAM project are split between capital and expense based on labor and procurement categories and capital includes contract labor.
- Project Management is 12.6% of the MAOP project cost and while this is higher than typical project management percentages, we believe it is appropriate considering the additional oversight a project of this complexity will require.
- The overall costs, as discussed above, are qualified as Class 4 estimates, which range up to a 30% to 40% high estimate excursion.

7.3 Conclusions

- Having data resident in native applications and linked minimizes data hand-offs and potential errors. In addition, this method reduces data latency from the time work is completed until the records are updated.
- Consistency of records will be a necessary and valuable asset for operations and integrity management.
- PG&E has admitted that some of the information in the existing GIS system is not sufficiently detailed to permit analysis of MAOP and other data attributes. Consequently, to some extent the expense associated with originally populating the GIS will need to be duplicated.
- PG&E will depend on the existing GIS records to populate the decision tree model, but will depend on the MAOP data validation and GTAM project to provide more granular

information in cases where pipeline segments are flagged for replacement by the decision tree, to permit a more detailed verification of the need for replace ment. This is one of the feedback mechanisms where PG&E intends to maximize the availability and use of system data.

- However, while PG&E indicated that it will provide a feedback device to amend the MAOP testing plan on an as needed basis as new informati on is discovered, we did not see any mechanism aimed at dealing with data errors discovered within the existing GIS through comparison with GTAM data. These potential errors may not be discovered until well after the decision tree process has identified a t risk segments. We did not see an integrated method to ensure that at risk pipeline sections discovered though data comparison would be re-inserted into the evaluation models for appropriate action. .
- PG&E intends to utilize a validation tool called Comp ass to integrate the component level database and the segment database. Use of this type of tool will provide validation and quality assurance in developing a composite GIS representation of the pipeline system.
- It appears that PG&E has developed a cost forecast using best available information and practices, but estimates, being Class 4, still contain a high level of uncertainty.
- The split between expense and capital for the GTAM project appears reasonable based on Jacobs' experience.
- The balance between software development and data conversion for the MAOP project is in line with what Jacobs has seen in the industry.

7.4 Recommendations

7.4.1 PG&E has admitted that some of the information in the existing GIS system is not sufficiently detailed to permit analysis of MAOP and other data attributes. Consequently, to some extent the expense associated with originally populating the GIS will need to be duplicated. Since PG&E's existing GIS and Pipeline Records Program cannot be relied upon as a comprehensiv e and accurate source of gas transmission information, cost concessions in the Pipeline Records Integration Program should be considered to compensate for duplicative efforts.

7.4.2 Implement a feedback mechanism to ensure that errors discovered within the existing GIS data through comparisons with GTAM data are handled expediti ously particularly any that would result in a segment's MAOP prior certification to be in question.

7.4.3 PG&E should revisit its cost estimates for GTAM and MAOP at least annually and recalculate balance of project capital and expense requirements based on project progress and new knowledge gained through the data examination. The CPUC should be provided with a report in a format that it specifies.

8.0 Project Management Office, Schedule , and Cost

8.1 Discussion

In this section, we examine the program management structure, and contingencies estimate.

Our findings, conclusions and recommendations are based on a review of Pacific Gas and Electric Company's (PG&E or Company) Pipeline Safety Enhancement Plan, Chapter 7 - Implementation Plan Management Approach And Estimate Risk Quantification and supporting work papers. The information contained in the documents reviewed were augmented by a teleconference interview with Brian McDonald and Steve Whelan conducted on December 8, 2011. Also on the teleconference call from PG&E were Chuck Ray and Carrie Cline.

PricewaterhouseCoopers LLP (PwC) assisted PG&E in structuring its overall Pipeline Safety Enhancement Plan (Implementation Plan or PSEP) management approach, governance structure, and control environment. PwC al so analyzed the preliminary estimates to assess the risk profile of each major component project's cost estimate and advised PG&E regarding reasonable contingency amounts given the current level of program cost estimates.

8.1.1 Program management structure

The Implementation Plan will impact some 273 cities in PG&E's service area. In a program of this size, complexity and duration, it has become a prudent practice for gas operators to establish a program management office (PMO). The key objectives of the PMO are to deliver the defined scope of work (project and program) , safety (employee, contractor, public and system), quality, cost , and schedule. A program management organizational structure is designed to deliver these objectives.

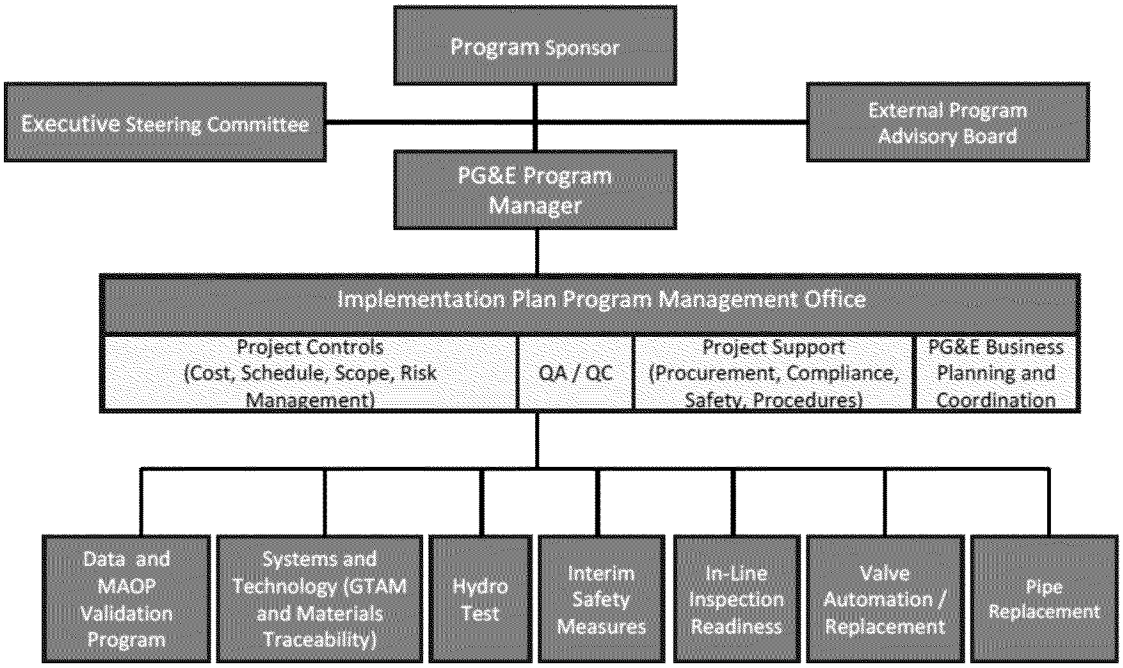
While the specific structure of a program management organization can somewhat vary based on a given program's size, complexity, and client needs, the PG&E program management organization structure, as shown in Figure 2, is consistent with industry practices, as are the roles and res ponsibilities of the major functions. The major functions of PG&E's programs management organization are:

- Project Sponsor
- Executive Steering Committee
- Program Manager
- Program Management Office (PMO)

While the PMO is comprised of the following functions:

- Program management
- Project controls (cost, schedule, scope, risk management, project managers)
- Project support (procurement, compliance, safety, procedures)
- Quality assurance/quality control
- Project management support

Figure 5 - PG&E Program Management Organization Structure



Much of the Implementation Plan work overseen by the PMO will be incremental to existing PG&E work related to pipeline operations and maintenance requirements. The PMO is responsible for the overall pro gram execution and to coordinate both inter -departmentally and geographically the multi - projects or work streams.

To accomplish the program execution, the total incremental full time equivalent Project Management Office staff per month is expected to be 22.25 (including the business planners) plus 4 external advisors, beginning in 2012. The PMO staffing estimate shows Project Controls having 11 full-time equivalents (FTEs) and Project Support having five FTEs.

PG&E plans to retain Parsons , a professional services firm with experience in setting -up, resourcing and running a PMO , to initially help the Company implement its PSEP and learn the project management organization structure. Employing an experienced firm in this manner brings with it several advantages:

- Proven structured control systems and processes
- Disciplined, experienced resources
- Capacity to transfer knowledge and leading industry practices

PG&E is working on a plan where by the PMO activities would transition from the outside contractor to PG&E. Contingent on appropriate personnel being trained by working with Parsons, PG&E expects that the transition could occur over a 12 to 18 month period.

8.1.2 Cost and Contingencies Estimate

The Association for the Advancement of Cost Engineering AACE International defines Contingencies as:

> "Contingency is a cost element of the estimate used to cover the uncertainty and variability associated with a cost estimate, and unforeseeable elements of cost within the defined project scope. Contingency covers ina dequacies in complete project scope definition, estimating methods, and estimating data. Contingency specifically excludes changes in project scope, and unforeseen major events such as earthquakes, prolonged labor strikes, etc. The amount of contingency in cluded in the estimate should be identified, as well as the methods used to determine the contingency amount. If risk analysis techniques were utilized to develop the contingency amount, the associated confidence level should also be identified."[19]

The pro gram management cost estimate is composed of four elements: incremental PG&E cost, contractor cost, mobilization cost, and office rental. These costs include both labor and material.

There are a myriad challenges facing the PSEP, which if not addressed could have adverse effects on the Implementation Plan budget, cost, and schedule. The most significant risks PG&E has identified include:

- Permits, both environmental and general, cannot be obtained in a timely manner to complete projects within an established clearance period
- Issues coordinating gas supply with other internal operating, maintenance and gas transportation activities disrupts scheduled work
- A level of outreach appropriate for each community's needs is not achieved
- Sufficient levels of skilled and qualified contractor labor cannot be retained

It is generally recognized that budget level estimates are a combination of science and art, relying on historical data and experience. Care must be taken not to include estimating allowances in the baseline cost to address increased likelihood of unforeseeable conditions. These costs are captured in the contingencies estimate. When indicating a contingency estimate, a confidence level is referenced. Factors considered in choosing a confidence level should be based on such factors as risk assumptions, project complexity, project size, and project criticality.

PG&E used a quantitative risk assessment approach to estimate contingencies using stochastic modeling and analysis, a well accepted industry practice. The Company has stated that the approach used to estimate allowance and risk-based contingency is consistent with the approach included in other PG&E applications previously approved by the Commission. We cannot validate this statement strictly with the information provided in the Pipeline Safety Enhancement Plan document.

8.2 Findings

8.2.1 Program Management Structure

- The governance approach and project control functions indentified in the PMO are consistent with industry practices: project controls, quality assurance/quality control, project support, and project managers. However, in organizations with a strong safety culture, the role of safety is a key PMO function, reporting to the Project Manager or higher level.
- The liaison, coordination between the PMO and PG&E operating departments is PG&E Business Planning and Coordination unit. This team serves as a conduit, integrating the PMO activities with PG&E Gas Operations.
- The inclusion of an external advisor function in the Program Management Organization structure has become more common. The roles and responsibilities of the external advisor vary depending on the challenges facing the company.
- PG&E plans to establish a separate PMO campus in Walnut Creek for back office activities such as engineering, cost control, quality assurance/quality control, etc. Front office, which consists primarily of work execution, is expected to be conducted regionally.
- The relationship between the Quality Assurance/Quality Control team and the work site inspectors is not clear.
- The objective of the Advisory Board to "Confirm project and Program participants are properly implementing established procedures and processes for their respective areas of responsibilities" appears to be similar to what is typically a quality assurance/quality control function.

[19] AACE International Recommended Practice No. 34R-05, TCM Framework: 7.3 – Cost Estimating and Budgeting, 2007, p.4

- The responsibility for compliance with requirements specified in CPUC decisions is not established. This is typically either an internal auditing or external advisor responsibility.
- PG&E suggests that a "potential role of the External Program Advisory Board is to coordinate the information and document flow between the PMO and external parties…" This role could be a conflict with the primary objective of an external advisor, that of independent opinion, compliance, and oversight.
- To address program resourcing and governance needs, PG&E has or plans to retain outside service for the following:
    - Project management company (Parsons)
    - Outside auditor as part of the Advisory Board
    - Specialist systems integration vendor
    - Construction Management partner
    - Draw down of project contingency funds

- PG&E is dedicating resources to manage and coordinate engineering, permitting, procurement and construction. Included within construction are field services, quality and safety management. The number of FTEs and cost for these functions are not quantified.
- At the time the Implementation Plan was submitted, PG&E was developing a detailed set of Program processes, controls and management tools to execute the PSEP. Typically these tools are referred to as a program execution plan or program management plan.
- There is an expectation that the PMO function will be transitioned to PG&E at some point.
- The information needs of external stakeholders will be determined by PG&E, Parsons and the External Program Advisory Board. There is no indication that PG&E will directly seek the reporting needs of the CPUC or other external stakeholders.
- PG&E is looking to expand the number of construction contractors to six or seven firms. To offset the potential loss of contract labor, the Company is examining how to keep contractors engaged during the winter construction period from November through January.
- An executive project committee is in place to reviews all project with a value of $20 million or greater.

8.2.2 Cost and Contingencies Estimate

- The program management cost includes incremental PG&E costs for the Program Manager and Planning Coordinator positions. It is not clear where incremental PG&E in-house costs for Engineering, Permitting, Safety, Field Inspectors or other departments, which are expected to assign resources to support the PSEP, are included in the program cost.
- We understand that the mobilization cost is based on PG&E's contract with Parsons. There is no discussion about similar costs for other contractors likely to be engaged in the PSEP. It is not clear whether the mobilization cost also included demobilization.

- The baseline estimate development and approach to estimate contingencies is based on well established cost estimating practices.
- PG&E is working with its PMO contractor to better define project level scope of work.
- PG&E indicted in the interview that material risk will not be significant because the Company has mitigated much of the risk by securing the major program material components from manufacturers – steel pipe and line valves – to mitigate this risk.
- Most of the cost estimates are budgetary level estimates (-15/+30). However, the Gas Transmission Asset Management project (GTAM) cost estimate appears to be an order - of-magnitude estimate. Referred to Section 7 - Pipeline Records Integration Program for additional discussion on GTAM.
- Some project streams, such as valve replacement and PMO activities will be largely repetitive. It is not clear whether a repetitive learning curv e is incorporated in the quantitative risk assessment approach.
- The analysis of PG&E's cost estimating approach found additional estimating allowances had been included to address the likelihood of unforeseeable conditions that might be encountered on a pr oject. PG&E refined its estimates to remove these embedded contingencies, so this no longer appears to be a concern.
- PG&E has adopted a 90% confidence level which results in a PMO total contingency of $6.1 million or 17.5% on a total baseline cost of $34. 8 million. The total contingency on the PSEP is $380.5 million or 21.1% on a total baseline cost of $1,803.4 million at a 90% confidence level.

8.3 Conclusions

- The Implementation Plan PMO organizational structure looks to provide a good framework. The organization and governance is based on current industry practices.
- The Program Management Office appears to be a lean organization. Both the baseline cost and contingency values appear low.
  - Document Management is a core project support function, but this reso urce is not included in either the PMO organization or baseline cost.
  - The number and type of subcontractors and their reporting relationships are not fully defined.
  - The number of field work quality and safety inspectors and the responsibilities and role of the PMO to this work needs to be defined.
- The program schedule is aggressive. As such, the schedule adds risk that the total estimated cost of the program may be exceeded.
- There does not appear to be project mitigation strategy that addresses the ri sks covered by the program's contingency.
- Before transitioning the PMO activities from the outside contractor to PG&E, the Implementation Plan PMO should be functioning as a high performance team. A 12 to 18 month transition period appears reasonable to achieve this transition.

- It appears no provision has been made for the preparation of a report describing the release of program contingencies.
- A complete summary of program management costs, not just those costs associated with the PMO should be prepared.

8.4 Recommendations

8.4.1 PG&E should be required to provide a copy of its PMO project execution/ management plan for the PSEP in a format specified by the CPUC.

8.4.2 PG&E should report to the CPUC monthly the forecast and actual contingency draw down in a format specified by the CPUC.

8.4.3 PG&E should update and run the quantitative risk assessment (QRA) model annually and provide a report in a format specified by CPUC.

8.4.4 Given the general recognition that the PSEP schedule is aggressive, PG&E should undertake the development of schedule contingency estimates based on the current Program completion goal as well as the schedule contingency estimates if the program duration were to be extended by 6 months or by 12 months.

8.4.5 There are numerous risks identified in connection with implementing the PSEP, PG&E should develop a risk mitigation matrix describing significant risks, their potential financial impact, management's mitigation strategy and the individu al charged with responsibility to continually track and determine the effectiveness of this strategy.

9 Appendix – Recommendations

Section	No.	Recommendation
Decision Tree Methodology	5.4.1	To ensure PG&E is following their decision tree and prioritization process, a random sampling of a small number of projects should be periodically conducted to verify the process results.
	5.4.2	PG&E should identify all transmission pipe installed between the effective dates of GO 112 and the federal regulations (generally between 1961 and 1970) where the strength test do cumentation is missing. For all such segments, the costs associated with all new pressure testing should be borne entirely by the Company.
Gas Transmission Valve Automation Program	6.4.1	PG&E should further define the benefits of the proposed Valve Automation Program in the context of risk avoidance vs. cost and in comparison with other leading industry practices. PG&E should take into consideration that this program may exceed industry practices, but may represent a program that is lacking in the industry to provide a higher justification for the program and its cost.
	6.4.2	PG&E should further research high false close rates experienced with ACVs; and define the potential implications as it applies to the contemplated expanded use in their transmission system.
	6.4.3	PG&E should annually review the state of technology on ASV valve error rates and determine if there is a compelling case to change operation of RSVs to ASV mode.
	6.4.4	In the event of a full pipeline breach or rupture and once the s ection of pipe is isolated, PG&E should be able to quickly determine the gas evacuation time and be able to convey this information to the first responders to enable better site protection decisions.
Pipeline Records Integration Program	7.4.1	Since GIS d ata cannot be relied on as a comprehensive and fully accurate source of gas transmission information, cost concessions in the expense portion of the Pipeline Records Integration Program should be considered to compensate for duplicated efforts. In order to support this, PG&E should be required to maintain a record of data duplication as discovered during the MAOP and GTAM projects implementation. This information will subsequently be used to determine the need for and level of potential expense cost concessions.

	7.4.2	Implement a feedback mechanism to ensure that errors discovered within the existing GIS data through comparisons with GTAM data are handled expeditiously particularly any that would result in a segment's MAOP prior certification to be in question.
	7.4.3	PG&E should revisit its cost estimates at least annually and recalculate balance of project capital and expense requirements based on project progress and new knowledge gained through the data examination. The CPUC should be provided with a report in a format that it specifies
Project Management Office, Schedule, and Cost	8.4.1	PG&E should be required to provide a copy of its PMO project execution/ management plan for the PSEP in a format specified by the CPUC.
	8.4.2	PG&E should report to the CPUC monthly the forecast and actual contingency draw down in a format specified by the CPUC.
	8.4.3	PG&E should update and run the quantitative risk assessment (QRA) model annually and provide a report in a format specified by the CPUC.
	8.4.4	Given the general recognition that the PSEP schedule is aggressive, PG&E should undertake the development of schedule contingency estimates based on the current Program completion goal as well as the schedule contingency estimates if the program duration wer e to be extended by 6 months or by 12 months.
	8.4.5	There are numerous risks identified in connection with implementing the PSEP, PG&E should develop a risk mitigation matrix describing significant risks, their potential financial impact, management's mitigation strategy and the individual charged with responsibility to continually track and determine the effectiveness of this strategy.