State of California
State Energy Resources Conservation and Development Commission

In the Matter of:	)	Docket # 09-AFC-04	**DOCKET**
	)	Exhibit 411	**09-AFC-4**
Oakley Generating Station	)	Pipeline Testimony of	DATE Mar 24 2011
	)	Robert Sarvey	RECD. Mar 24 2011
	)	Footnote # 4	
	)		

4 PG&E Gas Transmission Facilities Risk Management Report
http://www.cpuc.ca.gov/NR/rdonlyres/1150A3F6-7CF4-4349-9E2B-A84CB5D21BFF/0/2007PGEGTSRiskManagementAnnualReport.pdf

Pacific Gas and Electric Company®

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July 31, 2008

Mr. Raffy Stepanian
Utility Safety Section
Safety and Reliability Branch
Consumers Protection and Safety Division
California Public Utility Commission
505 Van Ness Avenue, 2nd Floor
San Francisco, CA 94102-3298

Dear Mr. Stepanian:

Enclosed is PG&E's Gas Transmission Facilities Risk Management Annual Report. In 2007, PG&E's Gas Transmission Risk and Integrity Management programs helped prioritize $49,600,920 of capital and expense projects to verify the integrity and reduce the risks for its highest risk gas transmission pipelines.

We are sending you this report to keep you informed about the efforts we are undertaking to assess the integrity and manage the risk of our pipeline facilities. As part of the Integrity Management Program, PG&E assessed over 284 miles of High Consequence Area (HCA) pipe in 2007. This included smart pig runs on lines 021E, 105B, 114, 153, and SP3 and completion of External Corrosion Direct Assessments (ECDA's) on over 228 miles of HCA pipe. As a result of these efforts, PG&E had assessed 509 miles or 56% of PG&E HCA pipe and 83% or 23 miles of StanPac HCA pipe, as identified in their respective 2004 Base Assessment Plans, by December 17th. The Federal requirement was to assess 50% of our HCA piping by December 17, 2007 and this requirement was therefore fulfilled.

If you have any questions concerning the program report, please contact Mr. [redacted] at (925) [redacted]. We would welcome the opportunity for a detailed discussion of this year's results and future plans.

Sincerely,

/S/

Robert Fassett

Attachment

Introduction

The mission of PG&E's Integrity Management Program (IMP) and Risk Management Program (RMP) is to operate a safe and reliable gas transmission system by ensuring compliance with the Gas Transmission Integrity Mgmt Program rule (CFR 49, Part 192 Subpart O) and effectively invest PG&E's resources in on-going assessment, investigation and mitigation of the highest risk pipeline and station facilities that are not covered by this rule. In 2007, the IMP and RMP directed $49,600,920 to projects focused on achieving these goals.

On December 17, 2003, the Office of Pipeline Safety issued a new rule, *49CFR Part 192 Subpart O*, requiring integrity assessments for pipelines in "High Consequence Areas" (HCAs). Currently, 935 miles of PG&E's gas transmission lines are in HCAs that need to be assessed by December 17, 2012. Due to the over testing required to assess the HCA pipelines, approximately 2200 miles of PG&E's gas transmission lines will be assessed by 2012. In spite of the scope of this rule, over 60% of PG&E's transmission pipelines will not be assessed. The high risk pipelines, in this population, will continue to be assessed and mitigated under PG&E's RMP.

Both programs are directed by the Risk Management Procedures (RMP) developed to ensure compliance and consistent application. The Integrity Mgmt Program is directed by RMP-06 and the Risk Management Program is guided by RMP-01.

The risk assessments that are utilized in these procedures were developed, and are being maintained, using a deliberative process that employs;
1) Industry best practices for risk management and
2) Steering committees composed of subject matter experts and the Risk Management Team.

Risk is calculated using a "relative" calculation methodology that assesses individual pipeline segments for both the likelihood and the consequences of a failure. The relative risk of each unique pipe segment is calculated by integrating more than thirty different datasets that are managed within PG&E's geographic information system (GIS).

The projects described within this report were selected based on two methodologies. The IMP projects were selected based on risk and geographic considerations. The RMP projects were selected based on multiple considerations including; risk, the likelihood of failure, the capability of reducing risk with optimum resources, or a combination of these and other operating objectives. In each case, projects are selected using a structured process that involves consideration of the available risk mitigation alternatives.

Starting in 2004, PG&E began to make significant investment in assessing the integrity of IMP covered pipeline segments. Since many of the highest risk pipelines are covered by the IMP rule, the voluntary spending in the RMP decreased. However, there is a substantial overall increase in pipeline safety resulting from the combination of both programs.

In 2007, PG&E continued its active participation in industry evaluations of integrity assessment methodologies. PG&E has been a part of leading the pipeline industry's utilization of Direct Assessment to assess pipeline integrity, and continues with representation on ASME's B31.8 committee (Including the System Integrity Supplement B31.8S), PRCI, and the NACE RP 0502 committee. PG&E also participates in, funds, and is a member of the board of directors for the one-call centers in California-USA North and USA South.

2007 Program Summary

A total of $49,600,920 was expended to work on and complete a number of integrity management and risk reduction projects, including:

- Completing over 50% of the HCA assessments identified in the 2004 Base Assessment Plan by December 17, 2007.
- Five smart pig inspections totaling 90 miles of pipe, including over 56 miles of HCA pipe. Digs are still ongoing, with 5 repairs made to date.
- Direct Assessment (DA) Inspections of 37 NACE Segments (NSegs) on 228 miles of HCA pipelines. Indications from the ECDA surveys led to 42 excavations, none requiring repair.
- Risk based corrosion surveys on 26 miles of non-HCA pipe on lines 0408-01, 0630-01, 0821-02, 1202-16, 2402-01, 2408-05, 107, 108, 109, and 300B were performed with some digs planned for 2008. .
- Participation in 2 agricultural shows (with a fair attendance of over 140,000 people for the two events).
- Erosion mitigation at 28 locations

2007 Significant Projects

Smart pigging – Smart pigging is an effective tool of assessing for external/internal corrosion and mechanical damage over long sections of pipeline. In 2007, $27,187,084 was spent for ILI (In Line Inspection) work, primarily for smart pigging of lines 021E, 105B, 114, 153 and SP3. These funds were also used in preparing lines 002, 303, 400, 401 and 21D for smart pigging.

Smart pig runs

L-114 MP 9.05 to 16.5 –This is a 22" line originally installed in 1942 with some sections replaced since then, primarily due to relocations and class location changes. The section inspected runs between PG&E's Antioch and Brentwood terminals in Contra Costa County. The line was successfully inspected with a Magnetic Flux Leakage (MFL) ILI tool on June 13, 2007. A large number of metal loss features of various sizes were identified on the pipeline using the ILI tool. However, most were quite small and only 5 were considered "immediates", requiring a lowering of the line pressure while these indications were excavated, examined and repaired as necessary. Three repairs were made to the pipeline.

L-153 MP 0 to MP 17.6 This is a multi-diameter line, originally installed in 1949. The line runs between PG&E's Irvington Station in Fremont and Fairway Crossover in San Leandro. This line had been identified for ILI inspection in part because of a concern the pipe might be susceptible to internal corrosion. While a number of internal indications were identified as a result of the inspection on July 20, 2007 using an MFL tool, there were no immediate indications. Excavations for direct examination of some anomalies are planned for 2008 but are not complete as of now.

SP-3 MP 167.3 to MP 197 This pipeline was originally installed in 1930 and then almost completely replaced in the 1970's. The line runs between Delta Fair station in the city of Antioch and San Pablo Station in the city of San Pablo. The oldest section examined of this 22", 24" and 26" pipeline was installed in 1955. This line had been identified for ILI inspection for a variety of reasons; including the relatively high stresses the line operates at, the large percentage of HCA mileage associated with the run and the ability to examine the line for internal corrosion damage. There was a tool failure near the end of the planned run, but since that last small section had previously been inspected using the DA method, no additional inspection is planned until the next scheduled assessment of the line. There were no immediate indications found as a result of the inspection on April 19, 2007, but excavation and direct examination of some anomalies identified by the tool are still planned for this year, 2008.

L-105B MP 0 to MP 11.8 This pipeline is 24" in diameter, and was originally installed in 1965 and 1966 with some sections replaced since that time. The line runs between Crockett station in Crockett and San Pablo station in San Pablo. There were no immediate indications found as a result of the in line inspection using an MFL tool on October 1, 2007 but excavation and examinations of various anomalies is planned for 2008. That work is not yet complete.

L-21E MP 64.4 to MP 114.9 This is a 12" line supplying gas to Napa and Sonoma counties and was originally installed in 1967. The line was selected for ILI using a Transverse Flux Inspection (TFI) tool due to the long distance of uniform diameter pipe, the tape coating on the line, the stress the line operates at, the need to examine the pipe seam and the ability of this tool to identify and measure very small longitudinal indications. The initial attempt to inspect the line in January resulted in catastrophic failure of the inspection tool. A second attempt on December 10, 2007 was largely successful, although a partial tool failure north of the town of Cloverdale will require a more complete assessment of HCA piping from Hopland to Willits prior to 2012. The inspection of line 21E revealed 94 immediate anomalies resulting in a pressure reduction on the line with digs that are still ongoing. Upon actual examination, few of these anomalies have been as serious as the tool indicated. Two repairs have been completed to date.

<u>2007 Carry over pigging activities</u>

L-401 MP 317.23 to 427.34 - Two additional segments were excavated and two minor anomalies were cut out in search of indications of internal corrosion. No internal corrosion was found and the anomalies were determined to be a result of the fabrication process.

<u>Smart pig preparation for 2008</u>

Line 303 was in the construction phase for a smart pig inspection. Line 002 will be inspected for the second time in response to the system integrity rule.

ECDA and Corrosion Surveys – These are cost-effective methods for verifying the integrity of pipelines where external corrosion or third-party damage is the primary threat. One or more aboveground tools can be used to assess the condition of the pipeline's coating and cathodic protection to determine if remediation is required. In 2007, $10,042,165 was spent inspecting HCA pipelines using the direct assessment method. For pipeline segments covered by the integrity management rule, PG&E utilizes the formalized External Corrosion Direct Assessment (ECDA) procedure as described by NACE RP-0502. ECDA is a four-step process that utilizes two or more above ground methods/tools to surveys and then direct examinations to verify the integrity of the pipeline. As part of our non mandatory Risk Assessment program addressing non HCA transmission piping considered at highest risk for corrosion damage, PG&E performs some additional corrosion surveys. These surveys are used to assess the condition of the subject pipelines corrosion protection, as well as to detect historical third party damage. Where these surveys indicate potential damage that may require action, excavations and/or mitigation are performed similar to what is prescribed in our system integrity program.

In 2007, 136 excavations in support of 228 miles of HCA surveys were completed. At each excavation site, the pipe coating was removed, the pipe blasted to remove any coating residue as well as any corrosion deposits, and it was then inspected for external corrosion (EC), internal corrosion (IC), stress corrosion cracking (SCC) and any mechanical damage. No evidence of SCC or IC was found, and no EC or mechanical damage requiring repair was found. At each location, the pipeline was recoated prior to reburial

In an ongoing effort to enhance our direct assessment program, two cased piping assessments were augmented using the EMW-C inspection system marketed by Profile Technologies, Inc. This tool was used in addition to two approved tools, as required by RP-0502 and 149CFR Part 192. This tool offers the promise of being able to detect debris in the annular space between the casing and the pipeline, and successfully did so at one location. Further testing is planned in 2008.

As part of PG&E's non mandatory risk assessment program, an additional 24 miles of pipe considered at high risk for external corrosion was inspected using close interval surveys, and pipeline current mapper. Excavations may be performed at some locations in 2008.

Seismic Mitigation – The review of line 177A's crossing of the Little Salmon Creek was completed and it was determined anticipated vertical movements at the fault of approximately 9 feet at multiple locations can not practically or economically be provided for while ensuring the line remains in service. An alternate plan that will allow for rapid shut down of the line through the use of check valves and the conversion of an existing valve to be a remote shut down valve was adopted.

Erosion Mitigation- $4,356,946 was spent on 28 projects to address erosion issues across the system. The largest single project involved rerouting of an exposed creek crossing at Soquel Creek.

Third Party Damage Prevention – PG&E continued its efforts to eliminate third party damage. PG&E's efforts focused on:

- Educational presentations to excavators and farmers.
- Landowner notifications.
- In 2006, PG&E formed company wide damage prevention task force for the purpose of heightening company awareness of third party damage prevention procedures and initiating best practices. In 2007 monthly communication meetings were established with mark and locate supervisors and the task force to internally communicate damage prevention issues.

- Participation in SAFE (Safety awareness for excavators), which PG&E funds and promotes. SAFE is a program to teach excavators about the USA law and to enhance excavation safety. These events are hosted by USA North.
- Continued standby during all excavations within 5' of our transmission pipeline facilities.
- Continued leadership in the High Desert Pipeline committee which was formed to coordinate first responder training and third party damage prevention communication in the southern portion of our territory.
- Coordination of external first responder training at the district level.
- Serving in a leadership role for Common Ground Alliance (CGA), an association of stakeholders who have a shared responsibility and goal of protecting public safety through the development, dissemination and adoption of damage prevention best practices. Their key accomplishment was the establishment of the 811 Call Before You Dig number.
- Continued use of a mobile computing system to enhance PG&E's mark and locate response.
- Participation in 2 agricultural shows (with a fair attendance of 140,000 people for the two events).

From 2006 to 2007, the number of known third party incidents damaging PG&E transmission pipelines remained at 10, down from 22 in 2005. PG&E caused incidents dropped from 3 to 1 between 2006 and 2007, while farmer caused incidents stayed at 1 and contractor incidents rose from 6 to 8.

Response to 2006 Eureka Pipeline Rupture

Last years report documented the August 19, 2006 rupture of line 177A (radial feed from Red Bluff to Eureka) near the community of Madd River and noted ongoing studies of the failure. Those studies have been largely concluded and engineering work has commenced on a number of activities, including the installation of remote shut-off valves and preparation of the mountainous section of the pipeline for an ILI.

Conclusion

After the eighth year of formalizing its gas transmission risk management program, PG&E continues to improve and expand its impact. A total of $49,600,920 was spent to evaluate and reduce the risk on more than 5766 miles of transmission pipelines. This work included a system-wide review for over 13 miles of new HCA's, and an updated system-wide risk analysis to be used in evaluating future projects.

By December 17th, PG&E had assessed 509 miles or 56% of PG&E HCA pipe and 83% or 23 miles of StanPac HCA pipe, as identified in their respective 2004 Base Assessment Plans. The Federal requirement was to assess 50% of our HCA piping by December 17, 2007 and this requirement was met.