Docket No. SA-534

Exhibit No. 2-DO

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C.

SUMMARY OF 2005 CPUC INTEGRITY MANAGEMENT
AUDIT OF PG&E

(2 Pages)

Pacific Gas and Electric Integrity Management Inspection
Executive Summary

Inspection Date(s):	October 17-21, 2005 (Week 1); October 31 – November 4, 2005 (Week 2); December 19 – 23 (Week 3)
Location:	Walnut Creek, CA
Lead Inspector:	Sunil Shori (CAPUC)
Operator Representative:	Chris Warner, Manager System Integrity
Executive Contacts:	Robert T. Howard, Vice President California Gas Transmission

System Overview

Pacific Gas and Electric (PG&E) owns approximately 5,534 miles of gas intrastate transmission. PG &E's gas pipeline system consists of pipe from eight (8) inches to thirty six (36) inches in diameter. The age of the systems ranges from the 1930s to present day. PG& E's transmission operates at MAOPs ranging from 1100 psig to 300 psig. PG&E wants to use a distribution center definition that Sempra Energy uses that states all lines receiving Intrastate, Interstate or International transmission pipeline, a California producer or a storage field is the point of where distribution begins. This would reduce their transmission mileage by 108 miles and HCAs by 9 miles. PG&E's gas transmission system contains approximately 981 miles of HCA mileage. PG&E's intrastate gas transmission system will be evaluated by ECDA for 732 miles and by ILI for 249. They will have pigged 1800 miles to achieve the 249 miles of ILI.

Integrity Management Program - Summary Conclusions
<u>Program Strengths</u>

1. At the time of the inspection, PG&E had already recognized areas where improvements were to be made to the IM program by virtue of an internal audit.
2. After implementing the IM rule preventive and mitigative requirements, PG&E initiated a measure to protect against third party damage such as standby monitoring by a qualified employee during excavation along their pipeline ROW when excavations where to be performed within ten feet of their pipeline facilities.

<u>Most Significant IM Program Concerns/Issues</u>

1. Various IM processes and overall documentation need to be more robust. For example, PG&E completed various evaluations to support IM decisions. However, many of these evaluations were not documented so that a history of decision-making activities was not preserved.
2. Operator created a new repair criteria call "Scheduled Other" which were indications of defects that were 80% through wall defects that they had performed an RSTRENG calculation on even though RSTRENG calculations are not valid for defects above 80% through wall. These anomalies are considered immediate repairs under the current IM rule. This is a considerable reduction in public safety for the operator to delay repairs to anomalies fitting this new repair criteria.
3. The periodic evaluation reviewed by the team was not sufficiently thorough, complete, and adequately documented for identifying potential new threats and preventive and mitigative actions. As an example, PG&E had no process in place to evaluate automatic shut off valves or remote control valves. Furthermore, PG&E proposed in their IM plan to wait until December of 2006 to develop this process.
4. While the quality assurance program specified program and process reviews, it did not specify criteria for acceptability. As an example, there was not acceptance criteria or methodology in place to determine if third party contractors where provided quality work for the pigging program.

Significant Pipeline Integrity Issues and Insights

1. To date, the PG&E is not repairing critical anomalies in accordance with rule requirements by the development of the "Scheduled Other" repair criteria.
2. PG&E only after this inspection is considering adding some LFERW pipe to the threat list on some pipeline

segments even though they knew of a recent in-service failure attributed to a bad LFERW seam. This led the inspection team to consider whether or not PG&E had in fact conducted any analysis to confirm if any part of their pipeline system was susceptible to fatigue and cyclic loadings.

3. PG&E admitted during the inspection that the person in charge of their root cause analysis for third party damage was self trained in conducting these analyses. The inspection team questioned the quality of such reviews and the quality of results obtained from them.

4. PG&E were reclassifying ECDA indirect indications during the first time use of this process on a particular pipeline segment.

5. PG&E was deciding not to dig a particular indirect examination indication even though the standard required it. Instead they were trying to use a corrosion coupon as another indirect inspection method. This appears to be inconsistent with the NACE RP for ECDA.