State of California
State Energy Resources Conservation and Development Commission

In the Matter of:	)	Docket # 09-AFC-04
	)	Exhibit 410
Oakley Generating Station	)	Pipeline Testimony of
	)	Robert Sarvey
	)	Footnote # 3
______________________________	)	

Exhibit 410
ATTACHMENT B PG&E's Integrity Management Program
Responses to Concerns Raised in CPUC's October 21, 2010 Letter
http://docs.cpuc.ca.gov/PUBLISHED/Graphics/128919.pdf

ATTACHMENT B
PG&E's Integrity Management Program
Responses to Concerns Raised in CPUC's October 21, 2010 Letter

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1- Exception Reports	Per the BAP, Line-400 (M.P. 82.33-142.61) was due for an ILI assessment in 2008. It had been selected for ILI due to the line being piggable and it having more HCA pipe than most piggable sections of Line 400. Although this segment had been scheduled for an ILI assessment in 2008, it was not performed in 2008. An exception report dated May 6, 2010 and approved by the Manager of Integrity Management on May 21, 2010, after the scheduled assessment year had been exceeded, moved the assessment to 2010 and converted the assessment method to ECDA. The exception report noted the change to 2010 was made because the segment did not meet all conditions per RMP-06, Section 5.4 (less than 5 miles of HCA, less than 1 mile of tape coating, and it does not have poor pipe condition reports) and "…to better level workload and funding requirements for Integrity Management and allow time for ECDA pre-inspection work to occur."	Line-400 was initially scheduled for In-Line Inspection (ILI) in 2008. However, after re-examination, PG&E determined that this line should be assessed using External Corrosion Direct Assessment (ECDA) in December 2009. Even though an exception report was filled out when the assessment method was changed, per the decision making flow chart in PG&E's Risk Management Procedure RMP-06 "Integrity Management Program" (RMP-06) Section 4.5, an exception report was not required since L-400 did not meet all the criteria for an ILI assessment. Line-400 ECDA was completed in 2010.
2 – Exception Reports	The same occurred for Line-401, (M.P. 82.34 – 149.19) which was slated for ILI in 2009. However, unlike Line-400, Line 401 met almost all conditions of RMP-06, Section 5.4 for choosing ILI over ECDA (i.e., this line has more than 10 miles of piggable line, operates at over 40% SMYS, has more than one mile of tape coating, and more than 5 miles of HCA mileage), <u>the assessment was not performed in 2009.</u> Instead, an exception report dated May 6, 2010 and approved by the Manager of Integrity Management on May 21, 2010, after the initial scheduled assessment year had been exceeded, moved the assessment to 2011 and converted the assessment method from ILI to ECDA. Exception reports, dated May 6, 2010 and approved by the Manager of Integrity Management on May 21, 2010, were also generated for Line-215 (scheduled for ILI in 2009, but ECDA'd in 2009); Line-57B (scheduled for ILI in 2008, but ECDA'd in 2008); Line-21D (scheduled for ILI in 2008, but ECDA'd in 2009); and Line-402 (scheduled for ILI assessment in 2012, <u>but changed to ECDA as the assessment method in 2012</u>).	Line-401, which contains 5.5 miles of High Consequence Area (HCA), was initially scheduled for ILI in 2009. Although Line-401 did meet many of the decision making flow chart criteria of RMP-06 Section 4.5 for an ILI assessment, PG&E determined that because this was a new pipeline installed in 1992, ECDA should be the assessment method which could appropriately address the threats identified on Line-401. An exception report was created to document this deviation from RMP-06 Section 4.5, per the exception report process documented in RMP-06 Section 18. Line-401 is scheduled for ECDA in 2011. Line-57B, which contains 4.9 miles of HCA, was inspected by ILI in 2001. Due to the fact there were no integrity concerns identified during this initial assessment to necessitate ILI as the re-assessment inspection method, ECDA was determined to be the method for re-assessment. Line-57B ECDA was completed in 2008. An exception report was created to document this deviation from RMP-06 Section 4.5, per the exception report process documented in RMP-06 Section 18.

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		Line-402, which contains 14.1 miles of HCA, was initially scheduled for ILI in 2012. Although the original run through the decision making flow chart identified ILI as the assessment method, after further analysis, it was not clear that this inspection was feasible for ILI due to system hydraulics. Even though an exception report was filled out when the assessment method was changed, per the decision making flow chart in PG&E's Risk Management Procedure RMP-06 "Integrity Management Program" (RMP-06) Section 4.5, an exception report was not required since Line-402 did not meet all the criteria for an ILI assessment. Line-402 is scheduled for ECDA in 2012. Line-21D, which contains 5 miles of HCA, was initially scheduled for ILI in 2008. However, after re-examination, PG&E determined that this line should be assessed using ECDA. Even though an exception report was filled out when the assessment method was changed, per the decision making flow chart in PG&E's Risk Management Procedure RMP-06 "Integrity Management Program" (RMP-06) Section 4.5, an exception report was not required since L-21D did not meet all the criteria for an ILI assessment. Line-21D ECDA was completed in 2009. Line-215, which contains 1.6 miles of HCA, was initially scheduled for ILI in 2008. However, after re-examination, PG&E determined that this line should be assessed using ECDA. An exception report was created to document this deviation from RMP-06 Section 4.5, per the exception report process documented in RMP-06 Section 18. Line-215 ECDA was completed in 2009.
3 – Exception Reports	Exception report of 12/11/08, generated for N-Seg 101-2008 (Sta 117+36) was used as basis for not excavating and examining all immediate indications from M.P. 42.24 – 44.61. Numerous exception reports, starting August 8, 2007 thru May 12, 2010, were generated for Line-21E. These exception reports were issued to justify not excavating three of 11 immediate indications	The exception report for N-seg 101-2008 was generated in December of 2008 under the ECDA program. Even though an exception report was filled out, it was not required because there was not an exception being taken to PG&E's procedure. This exception report describes the In-Process Evaluation and reprioritization per NACE RP0502 Section 5.8. The highest priority immediate indications were excavated and

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	reported by an ILI vendor, for examination plans delayed beyond 90 days, classification of indications downward from tool indications, delays in excavations beyond 365 days, and the generation of required root cause analysis reports delayed beyond 90 days, as required by RMP-11, Section 5.8.	the pipe condition did not reflect an immediate condition. Therefore, the remaining immediate indications, which were lower in priority than those already directly examined, were reprioritized from immediate indications to scheduled indications per NACE RP0502. The exception reports for L-21E were under the ILI program and were generated in response to the unique ILI data provided to PG&E by the vendor Intratech. This was the result of running a new technology, known as "Circumferential MFL", to detect cracks and/or axial defects in the seam weld along with general metal loss. The ILI report that PG&E received contained 94 reported "Immediate" anomalies. Due to the sheer volume, it was not feasible for PG&E to excavate and inspect them all within 90 days. Therefore, PG&E performed 16 excavations to inspect the worst reported anomalies. PG&E determined the majority of the reported "Immediate" anomalies were actually manufacturing flaws in the seam weld which didn't adversely affect the pipeline's integrity. PG&E prepared a Position Paper, which includes the input of several industry experts as well as results from extensive mechanical testing performed on pipe samples removed from Line-21E, to explain why the anomalies are not an integrity concern. The pressure reduction was maintained until this process was completed.
4 – Exception Reports	Exception report of May 12, 2010, for Line 21-E, for not excavating and inspecting all "scheduled" anomalies within 365 days, and instead taking 27 months following final receipt of the ILI vendor report.	The Line-21E exception report on 5/12/10 was in regard to a single "scheduled" anomaly (a dent affecting the seam weld) which originally wasn't recognized as a "Scheduled" anomaly. This situation was unique because this particular dent was not detected by the geometry run in January 2007. A dig plan was created based on the geometry results shortly after the completed run. The Magnetic Flux Leakage (MFL) ILI run, which is typically done in the same time frame as the geometry run, was not completed in January 2007. The MFL run was attempted but failed, and PG&E performed additional pipeline upgrades over the next several months to make the pipeline piggable. In December of 2007, PG&E completed another geometry run and a successful MFL run. Since a dig plan had already been created and completed based on the January 2007 geometry run, another dig plan was not created based on the new geometry data. Only a dig plan to

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		address the initial MFL data was created. During this subsequent MFL/geometry run over 10 months later this dent was detected. It was not anticipated that the new geometry run would contain new dents, but on a quality review of the data in 2010, the new dent was discovered. Upon discovering this new dent, PG&E added it to the dig plan on 5/5/10 and performed the bell-hole inspection in June of 2010. When excavated, PG&E found that there was actually not a dent as indicated by the second geometry tool. This report took exception to RMP-11 Section 5.6 per the exception report process documented in RMP-06 Section 18.
5 – Exception Reports	The exception report for L-2, dated 12/16/2009, which sought to delay the required issue of the root cause report from the PG&E required 90 days to 180 days, noted the reason for the exception (delay) was caused by "Corrosion engineering resources…focused on other higher priority aspects of Integrity Management. It is anticipated that the root cause analysis will be contracted to a vendor outside of PG&E for completion." The exception report also noted the exception was not unique to this project and suggested the 90 day requirement be changed to 180 days in the procedure.	The 90-day root cause time frame is not required by or contained in any regulation, but is a PG&E self-imposed requirement. Exception reports have been generated in regard to not completing the Root Cause Analysis within 90 days of receiving the field examination reports. Per the exception report process in RMP-06 Section 18.3, the process allows for the exception report initiator to make a recommendation as to whether a procedural requirement (that would not affect a regulatory requirement) should be changed. PG&E has considered changing its own internal requirement regarding the timing of root cause analysis completion. Public safety is not jeopardized since all direct examination and repairs have been performed, thus making the pipeline safe for the 7-year re-inspection interval. We will take your comments into account in addressing this issue.
6 – Exception Reports	A June 23, 2007 exception report, one of many issued for SP-3 (M.P. 167.31 – M.P. 198.05), which sought to delay the development of the inspection plan following receipt of the final ILI report from the vendor, noted as the reason for the exception: "Competing priorities within the ILI Engineering Team as well as turn over in personnel have delayed the completion of the SP-3 Dig Plan. Delays in creating this plan will not delay implementation of the dig plan beyond the required 365 days from the receipt of the Final ILI Report as required per RMP-11." In fact, several of these digs were delayed to October 1, 2010 (greatly exceeding the 365 days requirement to excavate and	The exception report for SP-3 to delay the development of the dig plan (Form G) beyond 90 days was taken from RMP-11 Section 5.5. There were zero "Immediate" anomalies were reported by the ILI vendor. Thus, delaying the creation of Form G did not have a negative impact on public safety (as documented on the exception report) because the dig plan would still be acted upon within 365 days of receiving the Final ILI Vendor Report. All digs classified as "Scheduled 1-year" were performed within 365 days of receiving the Final ILI Vendor Report. The digs mentioned in the CPUC's letter which the 365 day requirement were non-prioritized indications which were only being exposed for investigation/calibration purposes.

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	inspect all anomalies included on PG&E's Form G).	
7 – Exception Reports	Various exception reports were noted for work delayed due to environmental permits not being filed with, or obtained from, various permitting agencies. While some delays may be attributable to permitting agency requirements, it appears another reason for delays may be due to permits not being filed for in a timely manner.	PG&E has followed the exception report process as needed due to environmental permitting delays. PG&E's excavation locations are determined by the assessment data and are not flexible. Due to the large number of environmentally sensitive areas within PG&E's service territory, PG&E often encounters significant challenges with the various agencies during the direct examination process. PG&E immediately addresses all "Immediate" indications/anomalies with urgency and documents any schedule delays for non-Immediate issues through the exception process. The CPUC letter is not specific regarding which exception report the auditors felt appeared to be attributable to permits not being filed in a timely manner, however, PG&E will continue to ensure through the exception report approval process and regular communications that we are actively pursuing permits in a timely manner.
8 – External Audits	The USRB team reviewed reports for two internal audits related to PG&E's Integrity Management Program (IMP), which were done for PG&E by two different contractors. The first audit, conducted in December 2007, examined various IM assessments which had been completed by PG&E. It appeared that PG&E did not formulate a position/response to the 2007 audit findings until December 2009. The second audit, conducted in October 2009, focused its review on risk assessment and risk management aspects of PG&E overall IMP. By the time of the USRB audit, PG&E had not formulated a position/response on the findings from the audit.	PG&E's Risk Management Procedure RMP-06 "Gas Transmission Integrity Management Program" (RMP-06) Section 13.8 requires either an internal or external audit to be performed every other calendar year to ensure compliance with our procedures and that those procedures meet all regulatory requirements. The final report was received from the external auditors in December of 2007. Multiple teams were responsible for the items contained within this final report. Each team created individual position/responses and, for those recommendations that PG&E agreed with, changes were incorporated into various aspects of the IMP in a timely manner. The December 2009 response document was a merged document of the original team responses which were created shortly after the December 2007 final report. PG&E understands the CPUC's concern regarding the timely documentation of a response to the external reviews performed by consultants in 2007 and 2009. Although RMP-06 does require the audits to take place, it does not provide clear direction regarding a formal response. RMP-06 will be updated during the next revision to

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		bring more clarity and rigor to Section 13.8. Additionally, all corrective actions resulting from future audits will be tracked via PG&E's commitment tracking process that is managed by PG&E Gas Engineering Regulatory Support..
9 – External Audits	The 2007 audit review noted that RMP-09, Table 3.3.1, which defines PG&E's Pre-assessment Data List (Table A, and the Data Element Check Sheet) did not capture the girth weld coating as required ECDA data per NACE 0502. PG&E indicated it did not capture this data because it was difficult to locate; however, we believe difficulty should not prevent PG&E from obtaining this and all required data per NACE requirements.	Regarding Table 3.3.1 in PG&E's Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" (RMP-09), it is correct that the Pre-Assessment Data List (Table A) does not capture girth weld coating. PG&E's original response to this item is also correct; this data is typically not available. However, PG&E's RMP-09 Table A does require the collection and consideration of pipeline coating and, typically, the girth welds are coated in the same material as the pipeline. NACE RP0502 Section 3, Table 1 (ECDA Data Elements) does mention "Coating type – joints", however, Section 3.3.2 states "*The date elements were selected to provide guidance on the types of data to be collected for ECDA. Not all items in Table 1 are necessary for the entire pipeline. In addition, the pipeline operator may determine that items not included in Table 1 are necessary*". PG&E does not consider joint coating type a necessary data element, however, there are many data elements not listed in Table 1 that PG&E has additionally included for consideration. For example: pipe manufacturer and locations of reinforced concrete caps are two data elements PG&E considers in RMP-09 Table A which are not mentioned in NACE RP0502 Table 1.
10 – External Audits	The 2007 audit also recommended that the Direct Examination Process Flow Chart, Attachment A in RMP-11, be adapted into RMP-09 and that completion dates for final reports from RMP-11, Attachment A (45 days from completion of Root Cause Analysis, and within 135 days from completion of Field Inspection and Repairs) be specified for final reports. PG&E responded that it's then current process specified that its Root Cause Analysis needed to be completed within 90 days of receipt of the field examination report by the vendor; however "In many cases to date this has not happened due to lack of resources in the Corrosion Engineering Group who perform the	RMP-09 and RMP-11 do have distinct timelines regarding the direct examination requirements and it was initially deemed that the RMP-11 flow chart was not necessary to adopt into RMP-09. However, based on the CPUC's feedback, PG&E will reconsider adding a similar Direct Examination Process Flow Chart into RMP09. Regarding Root Cause Analysis, the external audit consultant misinterpreted the flow chart included in Appendix A of RMP-11 as this was created as visual representation of the overall ILI process that is detailed in the procedure itself. Per RMP-11 Section 5.8, the Root Cause Analysis is to be performed within 90 days of the receipt

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	Root Cause Analysis." PG&E noted that its ILI final reports are not tied to completion of repairs, but only completion of Root Cause Analysis being performed. PG&E further noted it considered the Root Cause Analysis as part of the Final PG&E report, and believed "…the report can't be finalized until this analysis is complete."	of the final Field Examination Report from the bell hole inspection vendor. RMP-11 Section 5.9 indicates that the PG&E Final Report is to be issued within an additional 45 days of the completion of the Root Cause Analysis. Although mathematically these add up to 135 days, if the Root Cause analysis is delayed then the Final Report will be delayed as well since the 45 day clock doesn't start until the Root Cause Analysis are complete.
11 – External Audits	Through the 2007 audit, PG&E also recognized that it did not have a mechanism for tracking recommendations made in the Root Cause Analysis. In Revision 5, dated May 13, 2010, PG&E modified Section 9 and 13 of its RMP-06 to require tracking of root cause analysis reports and recommendations; however, it has not clarified that root cause analysis needs to be performed before completing the assessment. This includes any monitored indications examined, since NACE 0502, Section 5.6 does not make an exception for monitored indications.	PG&E does have a mechanism in place for tracking root cause analysis recommendations through the Long Term Integrity Management Process (LTIMP). Root cause analyses are part of the final assessment report and, therefore, are required in order to close out the assessment documentation. While PG&E is in compliance with NACE RP0502 and 49 CFR Part 192, PG&E will revisit the RMP-06 sections mentioned and determine where the procedure can be made more clear regarding this issue on the next revision of the procedure.
12 – External Audits	The audit conducted in 2009 by PG&E's consultant noted that PG&E's current risk assessment methodology, although consistent with models in widespread use by many pipeline operators, could be improved upon. The review noted that PG&E had not well defined, and may have made too subjective, the provisions for assessing the performance of its model. The review recommended PG&E make use of statistical and graphic analysis to monitor the performance of its risk assessment process. However, as noted earlier, PG&E had not formulated a position on its consultant's recommendations. USRB believes PG&E needs to review these and future recommendations in a timely manner, and formulate appropriate actions based on these recommendations.	The final report for the audit conducted on PG&E's risk assessment and risk management portions of the Integrity Management program was received in October of 2009. The primary conclusion of this external audit was directed at the risk assessment (RA) methodology. PG&E has been using the relativistic risk ranking methodology commonly used by pipeline operators throughout the industry. The program review recommended PG&E migrate over to a probabilistic risk methodology. In response to this review, PG&E began transitioning its risk ranking methods in Spring of 2010 and will have completed the transition to a probabilistic methodology system wide for both transmission and distribution in 2011. This risk methodology migration is a large effort, but PG&E sees the value of the recommendation in order enhance its risk assessment process. Although PG&E apparently failed to make it clear to the auditors, PG&E had at the time of the audit already initiated a response to this 2009 audit and work was underway to address the recommendations.