NTSB SAFETY RECOMMENDATIONS
UPDATE ON PG&E'S ACTIONS
MAY 16, 2012

P-10-3: MAOP Validation (Urgent)

Use the traceable, verifiable, and complete records located by implementation of Safety Recommendation P-10-2 (Urgent) to determine the valid maximum allowable operating pressure, based on the weakest section of the pipeline or component to ensure safe operation, of Pacific Gas and Electric Company natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing.

NTSB noted the following in its March 13, 2012 letter:

- PG&E has met its California Public Utilities Commission (CPUC) deadlines related to records verification and MAOP validation of 760 miles of pipeline in HCAs.
- More than 1600 miles of pipeline in HCAs in PG&E's service territory have undergone records verification and MAOP validation.
- PG&E is working to complete records verification and MAOP validation for all pipelines in HCAs.

Accordingly, pending completion of action to satisfy Safety Recommendation P-10-3, this recommendation is classified "Open—Acceptable Response".

Update for P-10-3

On January 31, 2012, PG&E completed the work associated with all pipelines located in HCAs.

Using the records collected in response to NTSB's Recommendation P-10-2, PG&E has determined the valid maximum allowable operating pressure (MAOP), based on the weakest section of the pipeline or component and in accordance with the traceable, verifiable and complete standard, to ensure safe operation of PG&E's natural gas transmission lines in class 3 and 4 locations and class 1 and 2 HCAs that have not had an MAOP established through prior pressure tests. The MAOP validation for these lines was completed in August 2011. In addition, records collection and MAOP validation was performed for all remaining pipelines located in HCAs in January 2012. The lines validated through this effort included additional segments identified through class location changes as a result of the Class Location Study completed in June, 2011. In total, validation was performed for 2,088 miles.

PG&E submitted several filings to the CPUC in 2011 and 2012 regarding the progress including the completion of interim milestones associated with these efforts. Attachments P-10-3A through P-10-3E are the reports submitted to the CPUC showing PG&E's progress on this work. Accordingly, PG&E believes that it has successfully completed the actions requested by the NTSB under P-10-3. In order to comply with CPUC Decision 11-06-0017, PG&E is continuing work to validate all remaining transmission lines in non-HCAs which consists of more than 4,600 miles and is estimated to be completed by early 2013. Through April 2012, PG&E completed validation of 1,032 miles of non -HCA pipelines.

P-10-4: Strength Testing

If you are unable to comply with Safety Recommendations P-10-2 (Urgent) and P-10-3 (Urgent) to accurately determine the maximum allowable operating pressure of Pacific Gas and Electric Company natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing, determine the maximum allowable operating pressure with a spike test followed by a hydrostatic pressure test.

NTSB noted the following in its March 13, 2012 letter:

The NTSB is encouraged that PG&E has tested over 163 miles of pipeline as recommended, including 144 of the 152 pipeline miles having characteristics similar to those of the line that failed in San Bruno. For these miles of pipeline, PG&E has hydrostatically tested, replaced, or verified strength test pressure records. Also, over the next 3 years (2012-2014), PG&E plans to hydrostatically pressure test approximately 547 additional miles of pipeline. Pending completion of these efforts, Safety Recommendation P-10-4 is classified "Open—Acceptable Response."

Update for P-10-4:

<u>2011 Progress</u>

Overall in 2011, PG&E conducted strength tests on 163.5 miles of gas transmission pipeline and verified strength test pressure records for an additional 50.9 miles of pipeline, for a total of approximately 214.5 miles. In 2011, PG&E successfully strength tested, tied in, replaced or had strength test pressure records verified for 144.5 of the 152 miles of "Priority 1" pipeline (those segments identified to be similar to the pipeline segment that failed in San Bruno). (About 1.1 miles of the 152 Priority 1 miles has been abandoned in the area of the San Bruno rupture and will not be strength tested.)

PG&E has tested a total of about 39.5 miles of Line 132 (about 37 miles tested in 2011). An additional 12.6 miles is planned for testing in 2012. By the end of 2012, PG&E expects that all 52.1 miles of Line 132 (with the exception of the out of service segment that ruptured on September 9, 2010) will have been strength tested.

PG&E is conducting strength tests at 1.7 times the MAOP plus a 10% spike test where possible. In some locations where a pipe is operating at 72% of SMYS, the strength test may be limited to 1.25 times the MAOP plus a 10% spike to avoid exceeding 100% of SMYS. Also, when significant elevation changes cause the spike test pressure to exceed 100% of SMYS, PG&E has not conducted the spike test. This occurred on about 12 tests out of 97 tests completed in 2011. Additional information regarding 2011 test levels is shown in Attachments P-10-4A and Attachment P-10-4B.

PG&E provided the CPUC with monthly reports on the status of its strength testing program. Attachment P-10-4C shows the *Report of Pacific Gas and Electric Company on Status of Hydrostatic Pressure Testing as of December 30, 2011.*

<u>2012-2015 Progress and Plan</u>

PG&E's proposed Pipeline Safety Enhancement Plan (PSEP), currently before the CPUC for approval in R.11-02-019, outlines a 2-phase approach for strength testing. Phase 1 of the plan calls for testing or verifying records of 185 miles in 2012, 204 miles in 2013, and 158 miles in 2014. Phase 1 strength testing addresses the following types of pipes:

- Pre-1970, low-frequency electric resistant weld (ERW), flash welded, single submerged arc weld (SSAW), furnace butt welded, and lap welded pipe operating between 20% and 30% SMYS in urban areas.

- All urban-area pipes operating at or above 30% SMYS, unless it has been scheduled for replacement or an adequate strength test for the pipe exists.

During Phase 2 (which will begin in 2015), PG&E forecasts the need to strength test an additional 1,700 miles of pipeline. Including:

- All urban area pipes operating below 30% SMYS, unless it has been scheduled to be replaced or an adequate strength test for the pipe exists.
- All identified pipe not previously strength tested or replaced in Phase 1, which includes pipe located in Class 1 non-HCA (rural areas), unless an adequate pressure test exists for the pipe.

If approved by the CPUC, PSEP progress reports will be provided to the CPUC every six months and will include updates on strength testing.

Attachment P-10-4D shows the schedule for strength testing in 2012 and Attachment P-10-4E is the list of projects to be scheduled in 2013 and 2014. Through April 2012, nine tests have been completed for 18.9 miles and an additional 18.7 miles of records have been verified.

P-11-24: Work Clearance Procedures – Open pending receipt of further information on the completion of these efforts

Revise your work clearance procedures to include requirements for identifying the likelihood and consequences of failure associated with the planned work and for developing contingency plans.

NTSB noted the following in its March 13, 2012 letter:

The NTSB understands that PG&E is currently evaluating approaches to revise work clearance procedures and to update its SCADA leak detection capabilities (such as information technology solutions, *Lean Six Sigma* improvement processes, emergency backup relocation exercises, and a new *Data Historian* system to assist operators and planning teams). Pending receipt of further information from PG&E on the completion of these efforts, Safety Recommendations P-11-24 and -26 are classified "Open—Acceptable Response."

Update for P-11-24:

PG&E is nearing finalization of the Work Clearance Procedure and is committed to issuing the revised procedure to all employees involved in the gas clearance process before the end of the 2nd quarter of 2012. The working draft of the revised procedure is shown in Attachment P-11-24A. Attachments P-11-24B through P-11-24H are the job aids that support the work clearance procedure.

PG&E recognizes the importance of requiring a well-analyzed, fully and properly completed clearance form including risk assessment and contingency planning for all work that could potentially impact the system. Currently, work that has been identified as potentially impacting a station (or valve) control system or electrical supply is routed to the local facility/controls engineer for review to ensure the identified work will not pose a risk to the normal operations of the facility. Gas Control's final approval process verifies that all work associated with control systems or electrical supplies has been properly reviewed and if not, routes the draft clearance to proper reviewers before issuing final approval.

PG&E has also clarified and underscored the following in its revised clearance procedure:

- All sections and fields contained in the clearance form must be filled out completely. PG&E is building an electronic tool that will prevent the clearance form from moving forward for approval if it is incomplete.
- Individuals assigned the clearance supervisor role must have complete knowledge of the intended work and written clearance procedure before accepting this role.
- Field crew and control room operators must have clear and complete understanding of the scope and details of the clearance. The understanding of the clearance will be gained through a crew tailboard and phone calls to the control room.

PG&E's Control Room Management process includes a change management procedure that requires commissioning and functional check out testing (end to end testing) of all components at the field level connected to SCADA. Commissioning and functional check out testing is now being completed for all new and rebuilt installations in conjunction with work clearance activities. The requirement to write the step by step test sequence forces the engineering, field and Gas Control crews to proactively review the impact of potential equipment failure. These activities are additional measures PG&E is taking to ensure that facility equipment is capable of meeting normal operating requirements at all times.

As noted above, PG&E expects to issue the finalized gas clearance process before the end of the 2nd quarter of 2012. Web based training will be completed by all employees involved in the gas clearance process upon rollout of the revised procedure.

Through industry level benchmarking (site visits to more than a dozen major North American gas and electric utilities), PG&E has learned that the best in practice clearance processes utilize an electronic tool accessible to all participants involved in a clearance. Use of the electronic tool will ensure sustained conformance with the clearance procedure requirements and the completion of appropriate levels of review by engineering, maintenance, and Gas Control before clearance work begins. PG&E has committed funding to build an electronic clearance writing, calendaring, routing and approval tool. The electronic clearance tool will also allow enhanced Control Room visibility through the use of large video wall screens. It is anticipated the new electronic tool development and prototype rollout to field organizations by the end of 1st quarter 2013.

PG&E plans to further improve its clearance work processes by creating a Distribution Control Center by the end of 2012. The Distribution Control Center will oversee a uniform distribution clearance process nearly identical to the transmission process. PG&E's Utility Performance Improvement team (Lean Six Sigma experts) in conjunction with Gas Control, engineering, and field maintenance has undertaken the effort to write the distribution clearance process and it is on track to be completed by 3rd quarter of 2012.

P-11-26: Supervisory Control and Data Acquisition System Tools

Equip your supervisory control and data acquisition system with tools to assist in recognizing and pinpointing the location of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately spaced flow and pressure transmitters along covered transmission lines.

NTSB noted the following in its March 13, 2012 letter:

The NTSB understands that PG&E is currently evaluating approaches to revise work clearance procedures and to update its SCADA leak detection capabilities (such as information technology solutions, *Lean Six Sigma* improvement processes, emergency backup relocation exercises, and a new *Data Historian* system to assist operators and planning teams). Pending receipt of further information from PG&E on the completion of these efforts, Safety Recommendations P-11-24 and -26 are classified "Open—Acceptable Response."

Update for P-11-26:

PG&E is implementing three significant projects that will expand the current SCADA capability to predict and proactively manage abnormal events on our transmission and distribution system. The three projects are:

- Automated Valve Program implementation
- OSIsoft PI Data Historian integration with SCADA and GIS
- Distribution Control Center creation

These projects are the foundation of the broad initiative PG&E has undertaken to build a comprehensive controls framework to move from monitoring and reactive, to predictive and proactive.

<u>Automated Valve Program Implementation</u>

PG&E has embarked on an aggressive program to increase SCADA visibility and control capability on its transmission pipeline focusing on the most densely populated areas in our service territory. Upon completion of the Automated Valve Program PG&E will have real-time knowledge of pipeline pressures at least every 5-8 miles on large diameter pipelines in Class 3 and 4 areas. The transmission automated valve field site installations include new pressure and flow data being transmitted to the SCADA system providing additional information that will be utilized by new SCADA control tools and technologies to provide PG&E's Control Room operators with better situational awareness of pipeline conditions. The increased number of new field transmitters will result in a 100 percent increase from PG&E's current number of pressure transmitters connected to SCADA. PG&E will implement the Valve Automation Program in two phases. The table below shows the planned and completed installations of new pressure and flow monitoring visibility and valve control capabilities that PG&E will attain through the two phases of the Automated Valve Program:

Valve Automation SCADA Visibility/Capability		Phase 1 (12/31/14)	Phase 2 (TBD)	Cumulative Total
New Transducers to increase visibility of pressure and flow condition on pipeline system via SCADA	Installed since 10/2010	100		
	Pressure Transducers to be installed	440	660	1100
	Flow Transducers to be installed	30		30
Automated Valve Installations allowing automated or remote shutdown capability of transmission pipeline in Class 3 and Class 4 locations	Installed since 10/2010	36		
	Total to be installed	220	330	550
Total Miles of Class 3 and Class 4 Pipeline with automated isolation capability	Active Fault Crossings	16		
	Mile of pipe	522	1260	1782

In addition to the Valve Automation Program, the Control Room Management Alarm Management initiative will allow this large increase in system monitoring points to be incorporated into the Gas Control function while at the same time managing alarms from these points in a manner which better pinpoints the cause of the alarms and allow gas controllers to focus their efforts on the highest priority safety-related conditions. Phase 1 Valve Automation work will additionally provide technology, tools, and training to allow our gas controllers to make optimal use of the increased pressure and flow data and new automated isolation valves in an emergency. PG&E has contracted with a process and controls engineering vendor to implement new screens and tools using the OSIsoft PI Data Historian platform to aid gas controllers in detecting, analyzing and taking action to isolate the pipeline if a rupture or major leak event were to occur. These tools will package the operational data on a pipeline system to more clearly identify deviations from normal operations.

Each automated valve will be equipped with automatic and/or remote control capability designed to expedite the isolation of a section of pipeline. Each of these valve installation sites will send various alarm conditions to the SCADA system. Most importantly, an alarm indicating rapid pressure drop beyond the expected threshold will be received by the SCADA system and annunciated in the control room.

Additionally, PG&E will be investigating and pilot testing various available and in development leak detection, pipeline damage and ground movement technologies that could be tied to the SCADA system, providing real-time information and proactive identification of developing risks.

<u>OSIsoft PI Data Historian Integration with SCADA and GIS</u>

PG&E has been evaluating information technology solutions to deliver the right information to gas operators to allow them to make prompt, informed decisions related to pipeline safety. PG&E has begun work to integrate its OSIsoft PI Data Historian (described below), SCADA, and GIS systems to achieve an electronic platform designed to support the Control Room operators. PG&E is incorporating Lean Six Sigma improvement processes from a variety of internal stakeholders and industry consultants to ensure a solution focused on interoperability and usability. Examples include:

- PG&E has fully commissioned a new enterprise-wide OSIsoft PI Data Historian system that will be used to pull key relevant data together for operator and planning team use, and display material to operators on large screens in the control room. This platform will rapidly provide near real-time information to all areas of the Gas Operations organization, including engineering, planning, maintenance, and operations. This will provide better guidance and input for remote monitoring and controls, as well as for real-time operations.
- PG&E is using the new real-time OSIsoft PI Data Historian platform to support two large situational awareness screens. Billions of data records have been loaded into the OSIsoft PI Data Historian system representing more than a decade of historic SCADA information. New data is being added to the OSIsoft PI Data Historian system continuously, within seconds of being recorded in the SCADA system.
- In late December 2011, PG&E completed a SCADA enhancement that prioritizes alarms for appropriate operator action upon activation. This SCADA modification project provides PG&E's operating team the capability to filter alarms based on priority, data type, and geographic location. Alarm priorities can now be configured based on four categories: Emergency, High, Medium, and Low.
- On January 23, 2012, PG&E implemented a geographical based operating system for the consoles used by our gas system operators. Roles and responsibilities have been documented and individuals have been trained on the new geographical based north/south alignment. At any given time, operators are now responsible for monitoring the northern service territory or the southern service territory, not both. The completed human factors work (discussed below) and SCADA modifications contributed greatly to this effort.
- In conjunction with the new alarm management strategy, PG&E has completed work with human factors consultants developing a new SCADA visual coding design, including use of color, text and symbols in graphic displays to present alarm status and data quality. The new design will meet the requirements of API 1165 (Graphic Standard, Recommended Practice for Pipeline SCADA Display) by the middle of the fourth quarter of 2012.

Additionally, PG&E is moving forward with plans to build a new control center complex to co-locate transmission, distribution, gas dispatch and emergency response organizations. PG&E has completed benchmarking activities; including site visits with more than a dozen major North American gas and electric utilities. PG&E has begun the effort to select an external control room design consultant that will work with its facilities architect team to build out the new facility by April 2013.

Distribution Control Center Creation

PG&E is moving forward with plans to create a Distribution Control Center by the fourth quarter of 2012. Thousands of distribution pressure points and flow meters will be installed over multiple years and will increase the availability of equipment status data on SCADA. The expanded visibility and control capability of the distribution system will be increased from 300 pressure points currently to more than 6,500 pressure, flow, and control points. The table below reflects a forecast of the new visibility PG&E will attain through the Distribution Control Center project.

Distribution Asset Deployment Plans							
	2012	2013	2014	2015	2016	2017	Total
RTU	5	67	127	135	136	40	510

Control							
RTU Monitoring	0	0	128	128	129	105	490
Electronic Monitoring (Eagle)	12	203	378	378	378	151	1500
Electronic Monitoring (ERX)	130	500	500	500	500	0	2130

Both the Transmission and Distribution Control Centers will be supported by a common SCADA system and the OSIsoft PI Data Historian system, an enhanced clearance process, and integration with the Gas Dispatch and Emergency Response organizations. PG&E's current SCADA system has been reviewed and will allow expansion to add several thousand monitoring and control points.

P-11-3: 911 Notifications

Require your control room operators to notify, immediately and directly, the 911 emergency call center(s) for the communities and jurisdictions in which your transmission and/or distribution pipelines are located, when a possible rupture of any pipeline is indicated.

NTSB noted the following in its March 13, 2012 letter:

The NTSB notes that PG&E has made significant progress to address the emergency response issue; however, we point out that Safety Recommendation P-11-3 was classified "Open—Unacceptable Response" (see enclosures) on December 16, 2011, because the process outlined in PG&E's August 26, 2011, letter lacked sufficient detail and guidance to ensure prompt and immediate notification to 911 emergency call center(s). Specifically, the supervisory control and data acquisition (SCADA) operating data and alarms should be the basis for all 911 notifications. To satisfy Safety Recommendation P-11-3, PG&E needs to do the following:

- Establish 911 notification criteria based on the SCADA alarms received, such as loss of pressure, the magnitude and time rate of pressure loss, and changes in flow rates.
- Whenever the parameters exceed designated thresholds, Gas Control room operators should first contact 911, then focus on handling the event (a rupture, valve failure, venting gas, etc.), and, finally, contact corporate management.

The NTSB awaits a further response to Safety Recommendation P-11-3 regarding 911 notifications. However, because PG&E has initiated action to address the other issues identified in Safety Recommendation P-11-25, it is classified "Open—Acceptable Response."

Update for P-11-3:

PG&E has modified its initial 911 Notification Process based on the feedback received from the NTSB that SCADA real time operating data and alarms should be used to make 911 notifications. The modification of the process requires PG&E's control room operators to make the 911 Notification immediately based on the following SCADA alarm conditions:

- relief ***valve open alarm*** venting gas to atmosphere

- automatic shut off ***valve closed alarm*** indicating isolation of a section of pipeline
- activation of a ***pressure drop – rate high alarm*** indicating a high differential across one of the newly installed remote control isolation valves
- activation of a ***Lo-Lo pressure alarm*** indicating possible pipeline rupture (confirmed valid by verification of upstream and downstream pressure sites and correlated supply source metered flow increase)

For a complete review of the process, please see the updated 911 Notification Process (Attachment P-11-3A) and the tailboard document that is being used to train control room employees (Attachment P-11-3B).

PG&E is committed to building alarm triggering to be more predictive in order to further improve its public safety focus and enable PG&E to make timely notifications to 911 emergency centers. Enhanced SCADA alarming will continually be incorporated into PG&E's 911 Notification Process as PG&E progresses towards its goal of implementing a control room philosophy and strategy to ensure increased situational awareness, while enabling it to become predictive of, and responsive to, emergency operating conditions. Below are some examples of progress made to date:

- PG&E has implemented geographical based north/south alignment of its gas system operators by operating console in order to improve focus on real time monitoring. At any given time, operators are now responsible for monitoring the northern service territory or the southern service territory, not both.
- An enhancement to PG&E's SCADA system has been completed which prioritizes alarms for appropriate operator action upon activation. Alarm priorities are now configured based on four categories: Emergency, High, Medium, and Low. The SCADA enhancement also provides PG&E's operators with the capability to alarm filter based on priority, data type, and geographic location.
- PG&E has completed work with human factors consultants developing a new SCADA visual coding design, including use of color, text and symbols in graphic displays to present alarm status. The new design will meet the requirements of API 1165 (Graphic Standard, Recommended Practice for Pipeline SCADA Display) and is planned to be implemented in the last quarter of 2012.
- PG&E's Valve Automation Program has improved its predictive capability with the installation/retrofitting of 33 remotely controlled valves which are equipped with diagnostics which will activate a SCADA alarm to indicate an abnormally high pressure drop. A SCADA alarm is sounded if the sensing device detects a pressure drop greater than x (typically 30 – 50 psig) pressure/minute (x is a unique number for each valve location and is determined based on an engineering analysis). Under the current phase (Phase 1) of the Valve Automation Program, PG&E will install approximately 220 remotely controlled valves and 30 new flow meters in its system through 2014. The remotely controlled valves and meters with associated pressure and flow transmitters connected to the SCADA system will greatly improve PG&E's control room visibility.
- PG&E is now utilizing a new enterprise wide OSIsoft Pi historian system after rigorous conversion and compression testing of the data loaded into the system. OSIsoft Pi historian system is PG&E's new data base collection site for all gas SCADA data. This new system can and will be used for a variety of purposes beyond collecting historic data. For example, this new system will be the basis for information displayed on large control room video screens. Release of the new historian system now positions PG&E to prototype the feasibility of combination and composite alarming, and multi-site data analysis and alarming utilizing the expanding pressure and flow meter SCADA data, coupled with over a decade of historic stored data.

Additionally, the PG&E 911 Notification Process has triggers to immediately make 911 Notifications based on a field employee and/or an external public entity communicating information concerning a transmission or distribution facility involvement in a natural gas related event. PG&E feels that the additional reliance on non-SCADA based information broadens its responsiveness to the 911 emergency centers.

Once the SCADA alarm conditions have been triggered and/or non-SCADA based information has been received suggesting an emergency operating condition, PG&E follows a detailed procedure that explicitly requires Gas Control to notify 911 Emergency Response Centers. The procedure states in pertinent part:

> "In the event of an emergency operating condition that is known to be or has the possibility of impacting the public, property, or the environment, Gas Control is required to immediately notify the responsible 911 Emergency Response Center(s) to establish 'situational awareness'".

The 911 Notification Procedure details the communication protocol required to ensure the establishment of situational awareness of the emergency operating condition:

1. The Senior Transmission Coordinator will make the required immediate notification to the responsible 911 Emergency Response Center(s) using the Gas Control Contact Number Matrix, located in Section 2.4 of the Control Room Management Operations Manual.
2. The Senior Transmission Coordinator will provide a detailed description of the incident to the 911 dispatcher providing the following:
    a. Name of Senior Transmission Coordinator making the call
    b. Trigger indicator prompting 911 Notification
    c. Location or approximate location of incident
    d. Contact number to notify Gas Control if any additional updates are received
    e. ETA of PG&E First Responders if they are not yet on the scene.
3. The Senior Transmission Coordinator will also obtain the following information from the dispatcher at the responsible 911 Emergency Response Center(s).
    a. Name of dispatcher
    b. Any information the 911 Emergency Response Center(s) have regarding the nature of the incident, its location or pipeline marker.
    c. Are Emergency Response Agencies on Site?
    d. Additional contact number to reach 911 Emergency Response Center(s) for any additional information

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P-11-25: Emergency Response

Establish a comprehensive emergency response procedure for responding to large-scale emergencies on transmission lines. The procedure should:

- Identify a single person to assume command and designate specific duties for supervisory control and data acquisition staff and all other potentially involved company employees;
- Include the development and use of trouble-shooting protocols and checklists
- Include a requirement for periodic tests and/or drills to demonstrate the procedure can be effectively implemented

NTSB noted the following in its March 13, 2012 letter:

The NTSB notes that PG&E has made significant progress to address the emergency response issue; however, we point out that Safety Recommendation P-11-3 was classified "Open—Unacceptable Response" (see enclosures) on December 16, 2011, because the process outlined in PG&E's August 26, 2011, letter lacked sufficient detail and guidance to ensure prompt and immediate notification to 911 emergency call center(s). Specifically, the supervisory control and data acquisition (SCADA) operating data and alarms should be the basis for all 911 notifications. To satisfy Safety Recommendation P-11-3, PG&E needs to do the following:

- Establish 911 notification criteria based on the SCADA alarms received, such as loss of pressure, the magnitude and time rate of pressure loss, and changes in flow rates.

- Whenever the parameters exceed designated thresholds, Gas Control room operators should first contact 911, then focus on handling the event (a rupture, valve failure, venting gas, etc.), and, finally, contact corporate management.

The NTSB awaits a further response to Safety Recommendation P-11-3 regarding 911 notifications. However, because PG&E has initiated action to address the other issues identified in Safety Recommendation P-11-25, it is classified "Open—Acceptable Response."

Update for P-11-25:

PG&E has established a comprehensive emergency response procedure for responding to large-scale emergencies on transmission lines. The procedure:

- Identifies a single person to assume command and designate specific duties for supervisory control and data acquisition staff and all other potentially involved company employees;
- Includes the development and use of trouble-shooting protocols and checklists, and
- Includes a requirement for periodic tests and/or drills to demonstrate the procedure can be effectively implemented

A new Public Safety and Integrity Management team has been formed and is actively engaged in various facets of emergency preparedness planning. Responsibilities of this team include maintenance of the Gas Emergency Response Plan (GERP) to assist PG&E personnel in responding safely, efficiently and in a coordinated manner to emergencies affecting gas transmission and distribution systems. The plan describes roles and responsibilities of PG&E's emergency response personnel and includes a single person that assumes command and designates specific duties for SCADA staff and all other potentially involved company employees. In general, command will move to a higher level employee with increasing complexity as follows:

- If there is an event on the pipeline, the person initially in control in the Control Room is the Sr. Transmission Controller. This individual is very experienced and has access to all pipeline information including alarm data and volume and pressure data.
- If the event escalates, the Operations Emergency Center (OEC) in the division is activated and an incident commander is in place to manage the field operations and to coordinate with Gas Control.
- If it escalates further, the Emergency Operations Center (EOC) is activated and the incident commander of the EOC is the single person in charge.
- Co-location of control center (in first quarter of 2013) will facilitate command and control and will allow all information from transmission control, distribution control, and gas dispatch to be in one place.

Attachment P-11-25A contains the pages in Section 2.6 of the GERP that discuss emergency center activation, triggers to activation/escalation, and parties involved.

Attachment P-11-25B (Section 2.2 of the GERP), contains PG&E's emergency response protocol which includes two flow charts showing emergency call escalation through Dispatch and through Gas System Operations (GSO) and describes the resources assigned to gas emergencies. The GERP identifies when PG&E contacts 911 and also includes information regarding involvement of multiple agencies. Attachments P-11-25C and P-11-25D contain pages from the GERP that refer to PG&E coordination with 911 agencies. Attachment P-11-25E (Appendix C.1 of the GERP) discusses the responsibilities of the Incident Commander which include, but are not limited to:

- Conducting the initial assessment and communication

- Establishing the Incident Command and communication structure
- Using emergency plan checklists to ensure that proper notifications are made

PG&E's Gas Control team provides input and guidance regarding project requirements to ensure the proper SCADA equipment is deployed and control settings are enacted. Implementation of a robust near real-time Data Historian system will occur in control rooms and will also be available to emergency response teams, allowing enhanced situational awareness by those involved in emergency events.

Attachment P-11-25F (PG&E's Utility Standard EMER-6010S - Training and Exercising Gas Emergency Response Plans) provides requirements for conducting training and exercises associated with gas emergency response including:

- Annual joint exercise between PG&E and relevant first responders for each gas storage and gas regulation facility;
- Annual exercises at each of PG&E's 18 divisions; and
- Emergency Management Organization annual exercise involving PG&E's gas transmission pipeline system.

These exercises may include read-through exercises, table-top exercises, games, drills, functional exercises and full scale exercises. PG&E's Utility Standard EMER-6010s also requires a multi-year exercising plan.

Company Dispatch, Gas Control Operations and emergency response personnel must be trained on the Company's EMO dispatch and emergency response procedures annually, and any PG&E personnel with a role in an emergency operation are trained on the plan, as stated in EMER-1001S (Attachment P-11-25G). These requirements are also contained in the GERP as shown in Attachment P-11-25H.

PG&E has completed the following activities relative to training and measures have been utilized to evaluate effectiveness:

- Conducted training exercises with public officials and first responders to simulate gas curtailment scenarios and build greater understanding of how to prepare for potential events
- Increased the number of educational and interactive sessions, including practice drills, with first responders to meet demand and prepare for gas-related emergencies.
- Established a first responder pilot training program with the City of San Francisco and City of Fremont to share critical information with first responders.
- Completed Incident Command System training
- Conducted CAISO Gas Curtailment Exercise in August, 2011

Other activities include:

- Developed contact list for all local first responders (~1,800) to improve future communications and notifications
- Launched PG&E first responder website portal
- Provided maps, GIS data, and other information to first responders
- Established and implemented a Gas Control Process (911 Notification Process) in August 2011 and updated its process in response to the NTSB's recommendation P-11-3 (see Attachment P-11-3A).

PG&E conducted multiple joint exercises in 2011 and has additional workshops and exercises scheduled for 2012. An After Action Review Report from one exercise conducted in Milpitas, CA. on January 25, 2012, is included as Attachment P-11-25I as an example; after each exercise, such reports are prepared by the agencies participating in the training. Additionally, PG&E is constantly reviewing and improving emergency response procedures and institutionalizing them across Gas Operations. The GERP outlines the requirements for evaluating and validating emergency response procedures both in a training environment as well as after real events as shown in Attachment P-11-25J.

P-11-27: Automatic Shutoff and Remote Control Valves

Expedite the installation of automatic shutoff and remote control valves on transmission lines in high consequence areas in class 3 and 4 locations and space them at intervals that consider the factors listed in Title 49 Code of Federal Regulations 192.935(c).

NTSB noted the following in its March 13, 2012 letter:

The NTSB understands that PG&E is in the process of modernizing its system and is using technology to help identify and respond to potential issues. PG&E's automation of 11 shutoff valves in 2011, its plans to automate another 228 shutoff valves by the end of 2014, and its plans to enhance the SCADA information system are all positive actions. Pending completion of these efforts, Safety Recommendation P-11-27 is classified "Open—Acceptable Response."

Update for P-11-27:

PG&E has embarked on an aggressive program of valve automation that goes significantly beyond current code requirements and current industry practices as detailed in our Valve Automation Plan (Attachment P-11-27A) filed with the CPUC on August 26, 2011. PG&E will implement the Valve Automation Program in two phases with the second phase consisting of two components. Attachment P-11-27B shows the locations and priorities for these phases. Phase priority was aligned with the two primary factors in segment selection: population density and PIR. Table 4-3 (pg. 4-38) of Attachment P-11-27A shows the the various miles of PG&E gas transmission pipeline by Class, HCA and PIR value and highlights the focus of Phases 1, 2A and 2B.

Phase 1 will be implemented in 2011 through 2014 and will provide automated isolation capability for 276 miles of pipe in Class 3 HCA locations with a PIR >300 feet and Class 4 locations with a PIR > 100 feet. To automate these pipe segments, an additional 246 miles of adjoining segments are required to be automated, of which 125 miles otherwise would have been automated in Phase 2. Phase 1 work results in a total of 522 miles of pipeline with automated isolation capability. It also includes automatic controls for pipelines crossing 16 active earthquake faults. Phase 1 work will provide automated isolation capability for 185 valves, and is planned to upgrade the controls for 43 valves that currently have some remote control capability. At least 50 new valves will be required to allow for this automation. PG&E will also install 30 new flow meters to provide necessary flow information to facilitate decision making on when to isolate pipe segments.

Phase 2A consists of installing automated isolation capability on approximatley 535 miles of gas transmission line of which 345 miles are in Class 3 locations (approximately 130 valves).

Phase 2B consists of installing automated isolation capability on approximately 725 miles of gas transmission line, of which 235 miles are in Class 3 locations (approximately 200 valves).

PG&E anticipates that the CPUC's decision on the plan may be issued by the third or fourth quarter of 2012.

Since October 2010, PG&E has automated 36 valves. PG&E plans to perform automation work on 46 valves in 2012 (23 completed year to date). Additionally, PG&E is enhancing the SCADA information system by including additional information related to pipeline pressures, valve positions and gas flow rates. (See PG&E's response to NTSB recommendation P-11-26.)

P-11-28: Toxicological Testing

Revise your post accident toxicological testing program to ensure that testing is timely and complete.

NTSB noted the following in its March 13, 2012 letter:

The NTSB is aware that PG&E has conducted U.S. Department of Transportation post-accident training for gas maintenance and construction team supervisors and has created a cross-department team to enhance the accident reporting process. The NTSB would appreciate learning of the specific details of these programs and evidence to support the implementation and effectiveness of these programs. Pending receipt of this amplifying information, Safety Recommendation P-11-28 is classified "Open—Acceptable Response."

Update for P-11-28:

PG&E revised its testing processes to address two areas: 1) Timeliness in conducting post-accident testing and 2) breadth of the tested population in a DOT reportable event.

PG&E convened a cross functional team in the spring of 2011 to address this recommendations. As a result, the Company revised the Gas CPUC On-Call manual. The On-Call manual includes procedures that the Company uses to report gas incidents.

When there is a gas incident, the reporting person contacts Gas Control who in-turn contacts the On-Call representative. The On-Call manual was revised to include an additional step in the process which requires the On-Call representative to remind the supervisor to request drug and alcohol screening for all employees involved in a DOT reportable incident. The On-Call representative then emails the incident details to the GSO Gas Event Notification mailing list, which includes the PG&E Designated Employer Representative (DER). The DER is authorized by PG&E to take immediate action(s) to remove employees from safety-sensitive duties, or cause employees to be removed from these covered duties, and to make required decisions in the drug testing and evaluation processes. The DER also receives test results and other communications for PG&E, consistent with the DOT requirements and Company policies. The update to the On-Call procedures was made in July of 2011. Training for the On-Call representatives outlining the change in procedures was conducted by the Regulatory Support and Analysis team on July 18, 2011.

In November 2011 PG&E issued an update to its Gas Emergency Response Plan (GERP). Within this plan, PG&E provides instruction to PG&E personnel concerning when testing is required and the time limit requirements to perform testing. The requirement is set forth below:

Appendix B.3 – DOT Drug and Alcohol Testing – Post Accident

When is testing required?

- *Fatality or personal injury requiring admission to and an overnight stay in a hospital.*
- *Estimated property damage of $50,000 or more, including loss to the company and others, but excluding cost of gas lost.*
- *Unintentional estimated gas loss of 3 million cubic feet or more. Use Attachment 2 to Utility Procedure TD-4413S –Gas Event Reporting Requirements to determine if this gas loss criterion has been reached for pipeline punctures and complete severing of the pipeline.*
- *An event that results in an emergency shutdown of a liquefied natural gas (LNG) facility.*
- *Rupture or explosion, fire, loss of service, evacuation of people in the area, involvement of local emergency response personnel (e.g., fire, police, ambulance).*
- *All explosions, except those in areas where there is no gas service or where it is immediately clear that natural gas did not contribute to the explosion.*

Time Limit to Perform Testing

If any of the above apply, DOT drug testing is required for all covered personnel involved at the time of the incident/accident. Testing is required within 2 hours of incident/accident, but not to exceed 8 hours afterward. If the time to administer alcohol testing exceeds 2 hours, the reasons why the test was not promptly administered are documented.

PG&E will be revising its procedures to comply with regulations to be promulgated by the Pipeline Hazardous Materials Safety Administration (PHMSA) pursuant to amendments to the Pipeline Safety Act which require that as of June 2013, accident or incident notification is to occur at the earliest practicable moment following confirmed discovery of an accident or incident and no later than 1 hour following such confirmed discovery.

In July 2011 PG&E further revised its DOT administration practices to have the DER review all event notifications received via email. It is the DER's responsibility to contact local supervision and the On-Call representative to confirm the incident facts and the decision to conduct or forego post-accident testing following a DOT reportable incident. If the need for post-accident testing is indicated, the DER initiates contact with the external testing administrator who dispatches a collector. The DER will convey the time of the incident to the external testing administrator.

Training

All DOT leaders are required to complete DOT training every 2 years. In addition, employees are provided with checklists as quick reference guides. The most recent system wide training for Maintenance and Construction supervisors was conducted on June 14, 2011. The training material and roster are included as Attachments P-11-28A and P-11-28B. Additional training material is included in Attachment P-11-28B1

All new DOT covered employees are notified of their DOT-related responsibilities upon hire or transfer into a DOT-covered position. Materials provided to DOT covered employees are included as Attachment P-11-28C. The DOT Drug Free Workplace Administration team also conducts monthly training sessions and ad-hoc training to intact workgroups upon request. The Gas Operations Standards and Drug Free Workplace administration teams work together to notify supervisors and employees of changes in DOT requirements via bulletins to the Extended Leadership Team (ELT), which includes Supervisors, Managers, Directors and Officers –as well as through tailboards (scripted messages delivered directly to employees by local supervisors).

In addition to providing training to DOT covered employees and leaders, PG&E provides training to its collectors on an annual basis (Attachments P-11-28D and P-11-28E). Training was conducted on March 29, 2011 and May 4, 2012. The training included the following procedural changes to specifically address previous gaps:

- Collectors will be required to confirm incident time and testing deadlines upon arrival at the collection site.
- Collectors will be required to conduct alcohol testing FIRST, to ensure completion within the required timeframes, and will not conduct alcohol or drug testing beyond the allowed timeframes.

Collectors will be required to complete the Post Accident Communications Log to document any and all reasons associated with testing that was not completed, when testing protocol is not followed or to document issues that arose during the post-accident collection process. The testing log/summary is then submitted to the PG&E DER and retained as part of the incident file.

PG&E has established a team with members from Gas Engineering, Gas Control, and our internal DOT Drug Free Workplace Administration team to develop procedures which will ensure that the scope of the tested population is complete. Part of the objective will be to ensure that the determination of who is tested is made at the right level of decision-making and takes a broad enough perspective to include all potentially involved personnel despite any uncertainty with regard to the circumstances of the accident. Final revisions to the new standard are expected to be complete by June 30, 2012.

P-11-29: Integrity Management Program

Assess every aspect of your integrity management program, paying particular attention to the areas identified in this investigation, and implement a revised program that includes, at a minimum,

1) a revised risk model to reflect the Pacific Gas and Electric Company's actual recent experience data on leaks, failures, and incidents;
2) consideration of all defect and leak data for the life of each pipeline, including its construction, in risk analysis for similar or related segments to ensure that all applicable threats are adequately addressed;
3) a revised risk analysis methodology to ensure that assessment methods are selected for each pipeline segment that address all applicable integrity threats, with particular emphasis on design/material and construction threats; and
4) An improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment.

NTSB noted the following in its March 13, 2012 letter:

We note that PG&E has initiated the requested review of its integrity management program. Accordingly, Safety Recommendation P-11-29 is classified "Open—Acceptable Response," pending completion of these efforts and implementation of the revised program.

Update for P-11-29:

PG&E has embarked on a complete assessment of every aspect of its transmission integrity management program. At the core of this effort is a major restructuring of the personnel responsible for implementing the program. PG&E has established a team solely dedicated to transmission integrity management and whose sole focus will be to manage the integrity of the company's transmission assets. In addition, PG&E has hired a number of consultants recognized and respected in the industry as experts in integrity management to assist in an exhaustive review of its program's policies, procedures and tools. This review was conducted in close coordination and collaboration with PG&E in order to assure that PG&E's updated integrity management program meets all regulatory requirements, utilizes industry accepted practices, and leverages technical knowledge and experience from outside consultants to drive PG&E's program forward to improve both public safety and system reliability. The results of this review will be the basis for proposed modifications and improvements to the PG&E pipeline integrity management documents and the development of an implementation plan that outlines steps PG&E will take to exhibit all the attributes required for "Exceptional Performance" status as defined by 49 CFR 192. The review and implementation plan is expected to be available by mid-2012.

Following are additional actions PG&E has completed or is undertaking to enhance its Integrity Management Program:

1. Revised Risk Model and Integrity Management Program

   PG&E updated its risk model to support the 2011 "Baseline Assessment Plan" in March 2012. This work is performed at a minimum of one time a year and was approved on March 26, 2012 based upon updated HCA analysis and risk assessment performed on data collection through the end of 2011. This revision included changing the weighting of the risk factors of the existing threats in the risk algorithm to better reflect risk and threats related to long seam information and historical leak records that have been revealed through the extensive data collection efforts performed by the MAOP Validation Efforts (P-10-3) and feedback from PG&E's consultants. After review by PG&E's internal Threat Steering Committee, the revised risk model was approved by PG&E Management and the associated Risk Management Procedures were updated to reflect these changes. However, this work is not complete. PG&E will further develop its risk model to improve its consideration of stress corrosion cracking, internal corrosion, equipment and incorrect operations as threat terms in the overall risk algorithm. This is expected to be completed in 2012 and the results published in the 1st quarter of 2013 as part of the 2012 risk assessment.

In addition to the algorithm development, PG&E is actively working to improve its Integrity Management Program. Based upon recommendations received from its consultants and other relevant stakeholders, PG&E is revising its program and will update almost every procedure in PG&E's Integrity Management Program. The majority of this work is expected to be completed by August of 2012.

2. Information Systems To Ensure All Applicable Threats Are Adequately Addressed

PG&E is working to improve system records and work management systems to fully integrate the use of pipeline system as-built and maintenance information into the Integrity Management Program. A key initiative included in PG&Es Pipeline Safety Enhancement Plan submitted to the CPUC on August 26, 2011 is the Gas Transmission Asset Management Plan (GTAM). The project will substantially enhance and improve: the amount and the types of information that PG&E collects and maintains electronically about its pipeline system; the business processes for collecting, validating and retaining pipeline data; the traceability of materials used in the construction and maintenance of PG&E's natural gas transmission pipelines; and PG&E's ability to assess and mitigate potential public safety risks. The project establishes a technology infrastructure that supports enhanced new business processes to ensure data reliability is maintained and enables improved decision making capabilities related to the risks and integrity of the gas transmission system. By completing the objectives, PG&E will provide the complete and accurate pipeline information necessary to establish and sustain an effective GIS and data process for PG&E's integrity management program.

There are four primary objectives of the project:

- All asset data (location/connectivity, specification/features, and maintenance/inspection history) are tracked, managed, and stored using a software product and data management technique called linear referencing, which is a best practice for viewing/analyzing pipeline features, characteristics, and event history relative to specific reference points along the entire length of gas transmission pipelines.
- Materials are 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.
- Work management and data capture pertaining to maintenance and inspection processes (including Mark and Locate and Leak Survey) are more efficient, accurate, timely, and complete with rigorous quality assurance embedded. This will be accomplished by eliminating paper-based maintenance and inspection work processes and implementing automated work processes that manage Leak Survey, Mark and Locate, and preventative/corrective maintenance work from scheduling of work, field capture of information and verification/quality review of field captured data, through updating of the Core Systems.
- 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 asset health and condition with ability to perform risk and integrity analytics.

The implementation schedule for the project includes a series of four distinct phases, over a period of approximately 3.5 years (fourth quarter of 2011 through first quarter of 2015).

In advance of the project and in addition to the extensive effort noted in PG&E's response to Recommendation P-10-3 which will assist with the integrity management assessment and decision-making, PG&E is in the process of converting all paper records and databases documenting gas transmission leak history to a single electronic database. This includes all paper documents designed to identify and report historical weld seam leaks. The target date for completion of this database is mid-2012.

3. Revised Threat Identification Procedures

   PG&E has hired several consultants to assist in creating new threat identification procedures for the following threats:

   - Manufacturing
   - Construction
   - Internal Corrosion
   - Stress Corrosion Cracking
   - Fatigue (including cyclic fatigue)
   - Interacting Threats (including fatigue)

   PG&E's consultant developed the procedures and analysis tools for manufacturing, construction, and interacting threats (Attachments P-11-29A through P-11-29C). PG&E is incorporating these procedures and analysis tools into its Integrity Management Program (Refer to P-11-30) in 2012. PG&E has retained a consultant to provide an updated internal corrosion and a stress corrosion threat identification procedure that will also be integrated into PG&E Transmission Integrity Management Program during the 2nd quarter of 2012.

4. Improved Self-Assessment Metrics Regarding Pipeline Integrity Evaluations

   PG&E's consultant has been requested to evaluate PG&E's overall Integrity Management Program and as part of this effort will evaluate the performance portion of PG&E's Transmission Integrity Management Program. The goal is to assure that PG&E is meeting all its regulatory obligations including adherence to ASME B31.8S guidelines as well as providing recommendations for improving PG&E's self-assessment metrics utilized to evaluate whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment. PG&E's consultant will be issuing recommendations in 2012 with implementation to be performed in 2012-2013.

P-11-30: Threat Assessment

Conduct threat assessments using the revised risk analysis methodology incorporated in your integrity management program, as recommended in Safety Recommendation P-11-29, and report the results of those assessments to the California Public Utilities Commission and the Pipeline and Hazardous Materials Safety Administration.

NTSB noted the following in its March 13, 2012 letter:

The NTSB notes that PG&E has initiated action to address this recommendation. Accordingly, Safety Recommendation P-11-30 is classified "Open—Acceptable Response," pending completion of these efforts.

Update for P-11-30:

As noted in response to NTSB Recommendation P-11-29, procedures and analysis tools for manufacturing and construction threat identification were developed by PG&E's consultant. The consultant utilized these procedures and tools to perform a threat assessment on PG&E gas transmission pipelines using known pipeline values and, when necessary, a conservative assumption where pipeline documentation was incomplete. The result of this evaluation was provided to the California Public Utility Commission on February 3, 2012 (Attachments P-11-30A to P-11-30E). In addition, the results of the updated manufacturing and construction threat identification process were integrated into the 2011 Baseline Assessment Plan which was published in March 2012. Once the overall risk model is updated to more expressly consider threats including internal corrosion, stress corrosion cracking, fatigue and interacting threats, the updated risk model will then be included in future threat assessments and integrated into future Baseline Assessment Plans.

P-11-31: Public Awareness Program Continuous Improvement

Develop, and incorporate into your public awareness program, written performance measurements and guidelines for evaluating the plan and for continuous program improvement.

NTSB noted the following in its March 13, 2012 letter:

The NTSB notes that PG&E has developed written public awareness performance measurements and guidelines for evaluating the plan and for continuous improvement, along with performance measures in cooperation with CPUC. However, PG&E has not provided NTSB with these measurements and guidelines or provided evidence to support the program implementation or effectiveness. Pending our review of these details, Safety Recommendation P-11-31 is classified "Open—Acceptable Action."

Update for P-11-31:

On January 30, 2012, PG&E forwarded to the California Public Utilities Commission PG&E's "2011 Customer Safety & Public Awareness Communication Activity Report (Attachment P-11-31A). This report includes "Efforts to Measure the Impact of Safety Communications" using 1) the results of periodic surveys with targeted questions around the public awareness of pipeline and pipeline safety and 2) trends associated with damage during excavation. The initial results of the periodic surveys performed are included in the report, and show positive trends in the areas of Awareness of Pipeline Location, Awareness of Efforts to Maintain Safe Operations, Receiving Information, and Damage to PG&E's underground facilities.

In order to track effectiveness of its public awareness program, PG&E participates in the American Petroleum Institute/Interstate Natural Gas Association of America/Association of Oil Pipe Lines (API/INGAA/AOPL) joint survey program for pipeline operators, implemented by Harris Interactive (Harris). Harris is a communications firm with extensive experience conducting surveys for the pipeline industry. This survey is conducted every 4 years. Details of the survey process may be found at the following link: http://www.api.org/oilb-and-natural-gas-overview/transporting-oil-and-natural-gas/pipeline/~/media/Files/Oil-and-Natural-Gas/pipeline/pipeline_white_paper_statistical_significance-2.ashx

In 2012, PG&E has plans to further evaluate the effectiveness of its Public Awareness communication strategy based on the survey findings, as well as initiate an advertising campaign to reach its broad stakeholder audience.