PACIFIC GAS AND ELEC TRIC COMPANY

CHAPTER 4

INTEGRITY MANAGEMENT

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CHAPTER 4
INTEGRITY MANAGEMENT

A. Introduction

CPSD's report discusses aspects of PG&E's Integrity Management program, alleging violations of the federal integrity management regulations, 49 C.F.R. §§ 192.901 *et seq*. (Subpart O) and ASME B31.8S-2004 ("ASME B31.8S") in four categories: (1) data gathering and analysis; (2) threat identification, including manufacturing threat and cyclic fatigue; (3) risk assessment; and (4) the assessment method used on Segment 180. CPSD's claims are based on an ideal view of what an integrity management program can do – a view informed by the knowledge we have today from the San Bruno accident. Before September 9, 2010, no one – including CPSD and PHMSA in their prior audits of our Integrity Management program – identified the issues CPSD now claims constitute violations.

PHMSA began designing the integrity management regulations in 2002. Like the rest of the industry, we have been working to implement the regulations over the past 10 years. This effort is consistent with PHMSA's acknowledgement that development of integrity management programs is an evolutionary process. (See 49 C.F.R. §§ 192.907(a) and 192.911.) We acknowledge that we can do better – and we are taking concrete steps to do so, which are described below. But, this acknowledgement is not the same as saying that our program has not been both effective and in compliance with the regulations.

This chapter first discusses the development of our Integrity Management program (Section B). Section C then responds to CPSD's allegations in detail as follows:

- Section C.1 discusses our data gathering and analysis processes, demonstrating that our practices satisfied regulatory requirements and conformed to industry guidance.
- Sections C.2 describes how we considered potential manufacturing threats on our gas transmission pipelines, including specifically Segments 180 and 181 of Line 132 (on which CPSD focuses). This section refutes CPSD's

assertion that, prior to September 9, 2010, we should have considered DSAW pipe to contain a long seam manufacturing threat, and demonstrates that our consideration of manufacturing threats in the pre-San Bruno period was appropriate.

- Section C.3 explains our consideration of the threat of cyclic fatigue on our pipelines and the pre-San Bruno industry-wide understanding that cyclic fatigue is typically a negligible threat to natural gas pipelines.
- Section C.4 discusses our risk ranking model and explains that CPSD's criticisms are more appropriately described as differing subject matter expert viewpoints, not regulatory violations. This section also shows that the alleged shortcomings in our risk ranking algorithms did not affect how or when Line 132 and Segment 180 were assessed, as they were deemed high priority and assessed with the first half of our pipelines subject to the integrity management regulations and thus, the alleged deficiencies had no effect on the San Bruno accident.

Section D explains that we properly selected external corrosion direct assessment (ECDA) for Line 132, including Segment 180.

Finally, Section E describes efforts we have undertaken since September 2010 to improve our Integrity Management program.

B. Overview of PG&E's Integrity Management Program

On November 15, 2002, Congress passed the Pipeline Safety Improvement Act, which directed the Office of Pipeline Safety (OPS) to issue regulations prescribing standards to direct an operator's conduct of risk analysis and adoption and implementation of an integrity management program. OPS collaborated with other government agencies and natural gas transmission pipeline operators to discuss and determine the scope and requirements of such rules. Throughout this process, PG&E actively participated in industry and government evaluations of integrity assessment methodologies. OPS issued the integrity management regulations in a final rule that appeared in the Federal Register on December 15, 2003, and became effective February 14, 2004.

Our Integrity Management program built upon the Company's existing Risk Management program, a risk-based pipeline evaluation program that we developed and implemented prior to the regulator's and industry's movement toward risk-based programs that ultimately resulted in OPS's adoption of Subpart O. We developed our Risk Management program beginning in 1998 to mitigate risk across our pipeline system. The program analyzed all pipeline segments operating above 60 psig and performed a relative risk assessment that ranked each pipe segment based upon a formula that took into account the likelihood and consequences of failure.

Likelihood of failure depended on several factors, including pipeline characteristics such as material strength, diameter, wall thickness, operating pressure, the year the pipe was installed, and ~~vulnerability to third party damage, earthquakes, and landslides~~the pipeline's proximity to earthquake faults and areas of known landslide susceptibility. Factors relevant to the consequences of failure included population density, the size of the customer base that would be affected by an outage, and environmental impacts. We developed a risk assessment algorithm based on these factors using root cause technical data generated from pipeline failures that had previously occurred across the nation, as well as input of Company subject matter experts. Our Risk Management Procedures (RMPs)[1] 01 through 05 document the risk algorithm. RMP-01 provides an overview of the procedures that govern the risk management process. It describes the different factors used to assess risk, such as facility design attributes, existing conditions, potential threats and failure consequences. It also explains how the factors are weighted. RMPs 02 through 05 each address specific categories of potential threats.[2] Each RMP includes factors to be considered to determine the likelihood of failure of the pipeline due to the threat, and a description of how the factors are to be weighted. Based upon risk assessments carried out using these procedures, we prioritized the highest risk segments for assessment and/or mitigation efforts~~, which included in-line inspection, external corrosion direct assessment, pipe replacement, and deactivation.~~ .

[1] Ex. 4-1 through 4-12 contains all RMPs referenced in this testimony, which were the procedures in effect on September 9, 2010. Unless otherwise indicated, the description of the RMPs is of the version in effect at that date.

[2] RMP-02 addresses external corrosion. RMP-03 addresses third party threats. RMP-04 addresses ground movement threats. RMP-05 addresses the design and materials of the pipe segment.

Like our Risk Management program, our Integrity Management program is a systematic effort to identify and reduce pipeline risk. The Integrity Management program differs from Risk Management in that, pursuant to the 2004 federal regulations, it applies only to pipeline segments that meet the federal definition of a transmission line (49 C.F.R. § 192.3) and operate within a High Consequence Area (HCA).[3] The framework of our Integrity Management program is set forth in RMP-06, and procedures for elements of the program are detailed in RMPs 08 through 13. RMP-08 provides the procedure for identification, location, and documentation of high consequence areas. RMP-09 provides the procedure for conducting external corrosion direct assessment. RMP-10 provides the procedure for dry gas internal corrosion direct assessment. RMP-11 provides the procedure for in-line inspections. RMP-12 details the pipeline public awareness plan. RMP-13 provides the procedure for stress corrosion cracking direct assessment. (Currently, there is no RMP-07.)

We formally implemented our Integrity Management program in December 2004 with the filing of our initial Baseline Assessment Plan (BAP) on time and in accordance with the integrity management regulations. Our BAP listed all pipe segments in our gas transmission network that were within the scope of the federal rules, and outlined the integrity management assessment method we would employ for each such segment (which was determined through the steps outlined in the following paragraph).

Once we identified each segment within the scope of the Integrity Management program, we conducted data gathering and threat identification pursuant to RMP-06, Section 2. For each segment in the BAP, we gathered and reviewed pipeline data (including centralized data contained in our

[3] We continue to ~~address~~perform risk assessment on all transmission pipeline segments, including those that fall outside ~~the narrower regulatory definition~~of high consequence areas, through our Risk Management program. Also, PG&E's Integrity Management Program provides for certain mitigation actions in non-covered segments pursuant to 49 C.F.R. § 192.935.

Geographic Information System (GIS)[4]) to determine what threats listed in ASME B31.8S, section 2.2 were potentially present on each segment.[5] We then determined the method of assessment in the BAP depending upon the identified threats.

After we identified our HCA segments, gathered the pertinent pipeline data, and determined the threats and corresponding assessment methods to be utilized, we applied the relative risk component of our Integrity Management program consistent with Subpart O requirements. We determined the relative risk of each segment by evaluating each segment through our risk ranking algorithm (detailed in RMP-01). In accordance with the federal regulations, we prioritized the highest-ranking 50% of our HCA segments for assessment by December 17, 2007, and completed the assessments for all those segments by that date. We are on schedule to complete the required baseline assessments (and several reassessments) by the December 17, 2012 deadline under Subpart O.

C. CPSD's Alleged Violations

As described above, CPSD asserts various allegations with respect to the Company's past integrity management practices, and alleges that our practices constitute violations of the federal integrity management regulations related to data gathering and analysis, threat identification, risk assessment, and integrity assessment methodology. We address CPSD's assertions below.

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[4] GIS is an electronic database that was created in the 1990s as a reference tool for its gas transmission pipeline. The GIS allows for visual review of pipelines, and allows the reviewer to correlate the pipeline with geographic features such as roads, buildings, and other information about the surrounding environment. The GIS was originally populated from hardcopy data contained on pipeline survey sheets and maps. Since implementation, several upgrades have been made to the software underlying the GIS. Following the San Bruno incident, we have undertaken a complete overhaul of the data in our GIS as part of the MAOP Validation effort, which will become the foundation of an enhanced GIS, to be deployed in 2013.

[5] The federal integrity management regulations incorporate many of the standards set forth in ASME B31.8S, a set of guidelines related to pipeline integrity management promulgated by the American Society of Mechanical Engineers (ASME).

1. PG&E's Integrity Management Program Appropriately Gathered and Integrated Data

CPSD calls out two alleged "deficiencies" in our data gathering and analysis process. CPSD claims that: (1) we failed to gather all relevant leak data on Line 132 and integrate it into GIS, and that this violated 49 C.F.R. § 192.917(b); and (2) we did not ensure that only conservative default values were chosen on Line 132, or that the data was sufficiently checked for accuracy, and that, together, this violated ASME B31.8S, section 5.7(e). Contrary to these claims, our Integrity Management program gathers and integrates data necessary to perform threat identification and risk assessment on pipeline segments subject to the requirements of the integrity management rules. (49 C.F.R. Part 192, Subpart O.) As discussed in the expert testimony of John Zurcher, a gas pipeline industry professional with more than thirty-five years of experience in pipeline design, safety and operations, and a prominent and long-time member of ASME's B31.8 Section Committee (which revises and issues interpretations of ASME B31.8S), our data gathering and analysis practices, including the use of conservative, assumed values, is consistent with industry standards and the data gathering requirements of ASME B31.8S. (Testimony of John Zurcher, Chapter 5 at 5-6 to 5-8.)

Our data gathering process is documented in our RMPs. This process includes gathering centralized pipeline specification data (originally maintained in pipeline survey sheets sourced from job file documents, and now kept in GIS), as well as additional field collection efforts to confirm and supplement the centralized specification data, and provide additional information from construction, operations, and maintenance records. We use this information to identify the potential threats applicable to our covered pipeline segments. The results of the threat identification process are documented in our baseline assessment plans, beginning in 2004 and continuing through the present. PHMSA and the CPUC audit our procedures, data, and baseline assessment plans, and we also have them reviewed internally and by third party vendors versed in integrity management. PHMSA and CPSD integrity management program audits conducted prior to September 2010 did not identify the shortcomings in our data gathering and threat identification processes that CPSD claims today.

Although we have now undertaken a comprehensive effort to gather all pipeline records as part of our MAOP Validation effort (summarized below), PHMSA developed the integrity management rules with the knowledge that operators would lack complete records on some or all of their pipelines. Consistent with this concept, prior to the San Bruno accident, where pipeline data was not available, we used conservative, assumed values, an approach endorsed by the regulations. Mr. Zurcher examined our Integrity Management program and found it to be functional and consistent with industry practices and regulatory standards. As reflected in Mr. Zurcher's testimony, the "deficiencies" claimed by CPSD reflect subjective views and recommendations as to best practices, rather than objective failures to conform to standard industry practices or operators' general understanding of the requirements of 49 C.F.R. § 192.917(c). (Chapter 5.)

a. PG&E's Data Gathering and Integration Processes Satisfy Code Requirements

Section 2.3 of RMP-06 provides the overall process by which we gathered and integrated data, and used it to identify threats. For the initial creation of the integrity management 2004 baseline assessment plan (i.e., the initial assessment plan, to be completed by December 2012), our data gathering process collected pipeline attributes from available, verifiable information or information that could be obtained in a timely manner, such as from GIS. Prior to San Bruno, our data gathering process essentially consisted of two steps. We first reviewed centralized pipeline data, integrated with other geographic and surrounding environment data (for example, geographic regions subject to ground movement), to determine which threats were present on each HCA segment. GIS is a tool that allows the integration of point specific pipe data (such as year installed) with polygon or region data (such as potential landslide areas). For instance, a pipeline segment constructed with oxyacetylene girth welds (based upon the installation year) would be identified as potentially susceptible to a construction threat. Based upon this type of potential threat information, further analysis was conducted as necessary to review such pipe segments with these vintage girth welds to see if they intersect or traverse regions susceptible to ground movement. This type of data analysis and integration was used for the initial threat identification of a covered segment.

The second step of the data gathering process occurred during the pre-assessment phase.[6] We obtained additional information from locally-stored and archived pipeline records and interviews with pipeline engineers and field personnel to gather any relevant pipeline specification data. This additional step was done to validate the assessment method choice based upon the initially-identified threats and inform the future assessment steps through increased knowledge of the covered segment. Taken together, the overall data gathering process considered data elements from ASME B31.8S Appendix A, and satisfied the regulatory directive to integrate data to enable an operator to properly identify threats. (ASME B31.8S § 2.3.2.)

Where we were missing data, our practice has been to either conduct additional research in locally-stored and archived pipeline record sources. Alternatively, our practice has also provided for the use of conservative assumed values aligned with Company material procurement standards from the time period in which the pipe segment was installed, which (as explained in detail in the testimony of Mr.

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[6] Our data gathering process was not limited to the initial gathering undertaken to conduct threat identification. During the pre-assessment phase of both inline inspections and direct assessments, our practices called for an integrity management engineer to conduct additional data gathering from field offices and other distributed information sources. Pre-assessment data gathering was performed on all threat categories including, but not limited to, threats identified through the initial identification process. This involved looking to job files, interviewing employees responsible for maintenance on the pipe segment, and conducting a review of records in local Division and District offices to develop a qualitative understanding of the maintenance history and characteristics of the pipeline that is to be assessed. (RMP-09 § 3.3 (Ex. 4-8); RMP-11 § 3.3.(Ex. 4-10).). Information gathered during this process was analyzed to determine what effect it had, if any, on the integrity assessment process and assessment tool selection, specifically whether the direct assessment method could adequately address the pipeline threats identified for a particular pipeline segment. (RMP-09 § 3.3.2.1.(Ex. 4-8).)

Zurcher) is consistent with ASME B31.8S guidance.[7] (See, *e.g.*, ASME B31.8S Appendix A § 4.2 ("Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher.").)

As shown in the testimony of Mr. Zurcher, our approach to the data elements and sources from which we conduct initial data gathering, as well as the quality of the data in these systems, is consistent with industry practices for complying with Integrity Management data gathering and integration requirements. (Zurcher Testimony, Chapter 5 at 5-6 to 5-8.) As Mr. Zurcher elaborates (and contrary to the CPSD's criticism of the Company for turning to readily-available GIS data), pipeline operators did not interpret the integrity management regulations as requiring them to research and validate their pipeline data from scratch. Our development and use of information from GIS for our integrity management data gathering is consistent with common industry practices and industry understanding that regulatory requirements allowed them to rely on their prior data gathering efforts, rather than starting anew. (Zurcher Testimony, Chapter 5 at 5-4 to 5-8) The use of a GIS allowed us to efficiently aggregate large amounts of information (including data gathered during pre-assessment and fed back into GIS) and overlay pipeline segments on top of location-specific data that also contributed to the threat identification process (e.g., a pipeline constructed with vintage girth welds located in a geographic region subject to ground movement).

b. PG&E's Application of Conservative, Assumed Values Complies With Regulatory Requirements

Where we have lacked certain data regarding our pipelines, we have made measured use of conservative, assumed values pursuant to ASME B31.8S. Our practice has been to use the most conservative specifications (e.g., lowest specified minimum yield strength (SMYS)

[7] Pipeline materials and manufacturing processes evolved and changed over time, thus PG&E purchased materials with different characteristics at different times. For instance, large diameter double submerged arc welded pipe became available in the late 1940s, but was not available prior to that time.

value) from Company material procurement specifications for pipeline projects installed during the same time period as the pipe segment in question.[8] As Mr. Zurcher describes in his testimony, this practice is consistent with ASME B31.8S guidance, and allows us to properly prioritize pipeline segments for assessment in our risk evaluation process.

Our practice with respect to assumed values prevents us from prioritizing lower-risk pipe for assessment over high priority segments by avoiding unrealistic default values that do not reflect the Company's procurement history. Prior to the San Bruno incident, we conducted research into historic pipe procurement and pipe construction documentation to identify the minimum pipe specifications (e.g., SMYS values) used during various periods of our history. This research allows the Company to make conservative assumptions regarding the pipe characteristics based upon the year of installation and the diameter of pipe. In most (if not all) instances, and especially those involving large diameter pipeline, our historic procurement and construction standards have called for pipeline of significantly higher quality than the 49 C.F.R. minimums (e.g., 24,000 psig SMYS for pipe of unknown specification in the federal code). Were we to use the lower SMYS values instead of the characteristics of the pipe the Company purchased in the pertinent time frame, these pipe segments would receive falsely elevated risk scores, and would displace other pipe segments that would otherwise be addressed in the Integrity Management program in the proper order according to their actual relative risk. Thus, our measured use of conservative, assumed values informed by pipe procurement specifications increases the effectiveness of our risk assessments and our integrity management program as a whole. As reflected in the testimony of Mr. Zurcher, our use of conservative, assumed values, informed by minimum standards from the era in which the pipe was

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8 Where information relating to the type of long seam must be assumed, our practice is to use a default joint efficiency rating factor of 0.8, which signals the presence of a potential manufacturing threat, and triggers subsequent investigation and stability analysis. (Risk Management Instruction (RMI) 06, Rev. 01.)

constructed, is consistent with industry norms and has explicit support in ASME B31.8S. (Zurcher Testimony, Chapter 5 at 5-8.)

c. PHMSA and CPSD Integrity Management Program Audits Prior to September 2010 Did Not Identify the Shortcomings in PG&E's Data Gathering or Use of Conservative Assumed Values That CPSD Claims Today

Our data gathering and integration processes have been the subject of three audits conducted by PHMSA and/or the CPUC, as well as several audits conducted in-house or by a contracted vendor with integrity management expertise. Prior to the San Bruno accident, PHMSA- and CPUC-led audits (an informal process audit in 2004, and formal audits in 2005 and 2010) were conducted pursuant to PHMSA integrity management program audit protocols. (See*, e.g.*, Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety, *Gas Integrity Management Inspection Manual: Inspection Protocols with Results Forms*, (January 1, 2008) (2010 PHMSA Audit Protocol) (Ex. 4-13).)

Data gathering and integration processes are a focal point in these audits. For example, Section C.02 of the audit protocols instructs the audit team to "[v]erify that the operator gathers and integrates existing data and information on the entire pipeline that could be relevant to covered segments, and verify that the necessary pipeline data have been assembled and integrated." Section C.02.b of the audit protocol indicates that the audit team will determine whether the operator's data gathering process includes gathering and evaluating the set of data specified in ASME B31.8S, Appendix A, and that the operator considers several additional data elements, including past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and internal inspection records.

The Utilities Safety and Reliability Branch (USRB) of CPSD reviewed our data gathering and integration processes as recently as May 2010. In a report USRB sent to us six weeks after the San Bruno accident, the auditors noted weaknesses in our equipment and incorrect operations data gathering and integration. The USRB auditors did not identify any shortcoming with respect to our practices for gathering and integrating data related to manufacturing or construction threats. (See USRB, *Summary of May 2010 Audit Findings, Pacific Gas & Electric Integrity Management Program*, at 3 (Ex. 4-14).) USRB's review and lack of criticism of our data gathering and integration processes with respect to manufacturing and construction threats in the May 2010 audit stands in contrast to CPSD's post-San Bruno allegations regarding the same processes.

d. Data Accuracy Shortcomings Cited in the CPSD Report Did Not Contribute to the San Bruno Accident

As we now know, the information in GIS that Segment 180 contained 30-inch seamless pipe installed in 1956 was anomalous; such pipe was not available when Segment 180 was installed. However, due to the passage of time between the 1956 construction and implementation of integrity management rules in 2004, our Integrity Management engineers did not identify this segment as requiring additional records research. As described in the testimony of Mr. Zurcher, operators did not interpret the integrity management rules as mandating that they recreate pipeline data from scratch, and it was common industry practice to accept the accuracy of prior data gathering efforts unless there was specific information calling it into question. (Chapter 5 at 5-7.)

Even if we had identified that 30-inch seamless pipe was an incorrect specification, additional research would have shown that Segment 180 was constructed with DSAW pipe. As described in the next section, DSAW pipe would not have caused us to consider the segment subject to a manufacturing threat, or changed any other element of our risk and threat assessment. In short, the erroneous seamless designation did not have any effect on the threat identification or integrity assessment method we chose for Segment 180.

2. PG&E's Threat Identification Process Satisfies Regulatory Requirements

CPSD alleges several violations relating to our threat identification process. Specifically, CPSD alleges that (1) we did not consider known longitudinal seam cracks dating to the 1948 construction or a leak in 1988 on a long seam of the 1948 portion of pipeline 132, a failure that violated 49 C.F.R. § 192.917(b); and (2) we failed to identify an unstable manufacturing threat on Segment 180 and/or 181, which violated section 192.917(e)(3). To the contrary, and as described in the following sections, we gathered the appropriate data and appropriately considered the potential for Line 132, Segments 180 and 181 to be subject to a manufacturing threat.

a. PG&E Appropriately Reviewed Data Relating to Manufacturing Threats

The CPSD report faults us for failing to identify Segment 180 and Segment 181 as subject to a manufacturing threat that, according to CPSD, should have resulted in our conducting either a hydro test or in-line inspection of Segment 180. Consistent with ASME B31.8S guidance, however, we reviewed required data elements and, based on this review, properly concluded that neither segment was subject to an unstable manufacturing threat that would require a long seam assessment. Even if GIS had reflected that Segment 180 was constructed from DSAW pipe, as further explained below, the threat identification process would have yielded the same result.

Under ASME B31.8S Appendix A, section 4.2, an operator must consider the following data elements when considering whether a pipe segment is subject to a manufacturing threat:

a) Pipe material (e.g., cast iron, steel)
b) Year of installation
c) Manufacturing process
d) Seam type
e) Joint factor
f) Operating pressure history

For Segment 180 and 181, we were able to gather the required information relating to manufacturing threats from centralized records in our GIS database.[9] While the information in GIS regarding the Segment 180 seam type turned out to be incorrect, that error had no effect on the threat identification process or outcome for Segment 180. Both seamless and DSAW pipe (prior to San Bruno) had no industry history of long seam failure and were assigned a joint efficiency factor of 1.0 for threat and integrity assessment purposes. Pipe with a joint efficiency factor of 1.0 was (and is) not considered to be subject to a manufacturing threat under federal regulations. (See 49 C.F.R. § 192.917.) As stated in the testimony of expert metallurgist Robert Caligiuri, even today metallurgists consider DSAW pipe to be one of the highest quality welded pipes, a view that was also the case in 1956 when Segment 180 was constructed. (Caligiuri Testimony, Chapter 3 at 3-5.)

CPSD further faults us for failing to gather all leak data on Line 132 and integrate it into GIS for purposes of identifying manufacturing threats. However, under ASME B31.8S Appendix A, section 4.2, gas transmission pipeline operators are not required to review leak records for purposes of determining the potential for a manufacturing threat. While we did gather leak data as part of the pre-assessment process for Line 132, the failure to identify leak records does not violate ASME B31.8S data gathering requirements relating to manufacturing threats.

Contrary to CPSD's assertions, had our Integrity Management team identified records from the 1988 leak on Line 132 (approximately 9 miles from the rupture), these records would not have led us to consider similar Line 132 segments as subject to an unstable manufacturing threat. Documents discovered following the San Bruno accident indicate that the 1988 leak was a very small (pinhole) leak in the longitudinal seam of 30-inch DSAW pipe, the type of leak which does not constitute a structural integrity concern. (Material and/or Equipment

[9] Operating pressure history is available in our SCADA data historian. This data is reviewed if factors such as joint efficiency or seam type identify a pipe segment as subject to a manufacturing seam threat. In the case of Segment 180 and 181, neither seamless nor DSAW seam types would trigger this additional data gathering step.

– Problem or Failure Report, Line 132 (Oct. 27, 1988)(Ex. 4-15); Letter from PG&E Technical and Ecological Services to PG&E Gas System Design, regarding Bunker Hill 30" transmission line failure (March 1, 1989)(Ex. 4-16).) Due to the microscopic imperfection that led to the leak, our Technical and Ecological Services group could not find the location of the leak in the weld. As Mr. Zurcher states in his testimony, even DSAW, considered ~~among~~one of the ~~strongest and most reliable~~best performing types of pipe (and given a joint efficiency rating of 1.0), may experience these small, pinhole-type leaks from time to time. (Chapter 5 at 5-10 to 5-11.) However, leaks of this type do not signal the presence of unstable manufacturing defects, as they have not been found to lead to pipeline ruptures. Thus, even if our data gathering process had located records relating to the 1988 leak, there would have been no change in our manufacturing threat analysis, and no change to the integrity management assessment method used on Line 132 and Segment 180.

b. Section 181 Was Not Subject to an Unstable Manufacturing Threat

In a series of speculative assumptions, CPSD faults us for not identifying Segment 181 (adjoining and north of Segment 180) as subject to an unstable manufacturing threat. CPSD claims that proper consideration of this segment would have led us to hydro test or conduct an in-line inspection of Segment 181. This, in turn, would have caused us to discover that Segment 180 was constructed with DSAW pipe. That discovery would have led us to conduct a hydro test or in-line inspection on Segment 180, which would have identified the defective pups towards the south end of Segment 180. CPSD's theory is speculation built upon speculation and reflects a misconstruction and misunderstanding of ASME B31.8S and federal regulations.

It is important to understand that, when it comes to manufacturing and construction threats, the integrity analysis is a two part consideration: (1) whether the covered segment has a manufacturing or construction threat; and (2) whether the threat is stable. It is also important to understand that there are long seam and non-long seam manufacturing threats, each with different requirements for determining pipeline integrity. Not all manufacturing and construction threats are related to the long seam of the pipe.

Our records accurately indicate that Segment 181 was constructed in 1948 from 30-inch DSAW pipe manufactured by Consolidated Western. Prior to San Bruno, this type of pipe did not have a history of pipeline failure, either in Company or industry experience, and was assigned a joint efficiency of 1.0 under both the federal integrity management regulations and our Integrity Management program. Contrary to CPSD's assertion, prior to San Bruno there was no reason for us, or any operator, to conclude that DSAW pipe contained a potential manufacturing seam threat under the integrity management rules. While Segment 181 was identified in our 2004 BAP as subject to a potential manufacturing threat, this designation was due solely to the fact that the pipe in Segment 181 was over 50 years old, not because a suspected or known manufacturing seam threat existed.

As mentioned above, there are two types of manufacturing threats: long seam and non-long seam related. Per ASME B31.8S Appendix A, section 4.3, pipe greater than 50 years old is grouped with mechanically coupled pipelines and pipelines constructed with oxyacetylene girth welds as at risk of failure if exposed to low temperatures or if located in an area of ground movement (these are examples of non-long seam related manufacturing threats). If exposed to such conditions, ASME B31.8S requires an operator to initiate a pipeline movement monitoring program, and to take appropriate intervention (e.g., relocation, replacement). Neither the age of the pipe, nor the presence of substandard girth welds, constitutes a manufacturing threat related to the long seam (which would require a pipeline operator to take altogether different integrity assessment action).

The 50-year criteria and associated monitoring program is in stark contrast to the next paragraph in ASME B31.8S Appendix A, section 4.3, which states that a manufacturing long seam threat is considered to exist only on pipeline segments built with pipe with a joint efficiency factor less than 1.0 or constructed from low-frequency ERW or flash-welded pipe. (ASME B31.8S Appendix A § 4.3.) ~~Operators are~~

~~only~~Initially, operators were required to analyze pipe with these types of manufacturing seam threats to determine whether the segment must be prioritized for long seam assessment in the event of an operating pressure excursion above the highest actual operating pressure experienced in the five years preceding identification of the high consequence area~~.~~[10] and monitor for changing conditions. (49 C.F.R. § 192.917(e)(3); ASME B31.8S Appendix A § 4.4.) Because Segment 181 was constructed from DSAW pipe with a joint efficiency of 1.0, it was not identified in either 49 C.F.R. § 192.917(e)(3) or ASME B31.8S as subject to a manufacturing seam threat that would require investigation into operating pressure history, or the potential use of an integrity assessment method designed to address long seam defects.

Assuming, for the sake of argument, that Segment 181 was subject to a manufacturing seam threat (despite being constructed with DSAW pipe), CPSD's theory regarding the required integrity assessment on Segment 181 (and in turn, Segment 180) does not hold. Absent a pressure excursion as described in section 192.917(e)(3), a stable manufacturing seam threat is not rendered unstable, and no seam assessment is required for a stable manufacturing threat. As discussed below, contrary to CPSD's assertion, the operating pressure on both Line 132 and Segment 181 did not exceed the highest operating pressure experienced in the five years prior to our identification of Segment 181 as an HCA. As a result, Segment 181 would not have been deemed subject to an unstable manufacturing threat under the integrity management regulations, even assuming (incorrectly) that DSAW pipe was considered to be subject to a manufacturing seam threat.

In order for CPSD's argument to hold up, the following assumptions must be true: (1) the DSAW pipe in Segment 181 had a manufacturing seam threat, (2) this threat was rendered unstable during either the

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[10] Under 49 C.F.R. section 192.917(e)(3), the applicable 5-year period in which the previous highest operating pressure is determined as the five years preceding identification of the pipeline segment as being located in a high consequence area. ASME B31.8S states the "past 5 years" as the time in question.

2003 or 2008 planned pressure increase on Line 132, (3) we prioritized Segment 181 for a hydro test, (4) during the process of excavating sections of Segment 181 to install the assessment equipment, Segment 180 was noticed by the field employee to be constructed from DSAW pipe, and (5) since this information did not match the GIS records for Segment 180, we would have initiated further investigation into the records related to Segment 180. Even making each of these assumptions, the most that we would have learned regarding Segment 180 would be that it was constructed from DSAW pipe, rather than seamless. For CPSD's theory to then reach Segment 180, the series of attenuated assumptions must begin again and each be (erroneously) accepted as true for Segment 180.

As discussed above, under ASME B31.8S and the integrity management regulations, DSAW pipe had the same joint efficiency factor as seamless pipe and, prior to the San Bruno incident, was not known by us or through industry experience, to be subject to manufacturing threats or seam failures. (Zurcher Testimony, Chapter 5 at 5-9 to 5-13.) Nor, as discussed below, is CPSD correct in asserting that we should have considered DSAW pipe to contain a manufacturing seam threat based on the documentation CPSD has identified after the San Bruno accident. The layers of assumptions underlying CPSD's theory do not support CPSD's conclusions.

c. The Data CPSD Points to as Potential Indicators of Manufacturing Threats on Segment 180 Are Inapplicable

CPSD refers to a variety of data it believes should have led us to conclude that Line 132 was subject to unstable manufacturing threats that would require a long seam integrity assessment. The bulk of the information identified by CPSD, however, relates to pipe of materially different specifications than the pipe used to construct Segment 180 (and the remaining portion of Line 132 built in 1948). Any long seam issues identified on these unrelated pipe segments are not applicable to the integrity analysis for pipe used to construct Line 132. As discussed below, the information that is potentially relevant to the integrity analysis for Segment 180 (specifically the 1948 construction inspection notes and the 1988 leak record) does not indicate the presence of unstable manufacturing threats that would lead to in-line inspection or hydro testing.

CPSD faults us for not gathering and analyzing data concerning manufacturing imperfections discovered by girth weld radiography during the 1948 construction of parts of Line 132. CPSD claims that, having noted indications of long seam imperfections during radiography in 1948, we should in 2003 and thereafter have identified Line 132 (or at least the portions constructed with 30-inch DSAW pipe manufactured by Consolidated Western and installed in 1948) as subject to unstable manufacturing threats. However, the long seam imperfections identified during the 1948 radiography do not constitute unstable manufacturing threats because that pipe had been hydro tested during the pipe manufacturing process.

As described in a Moody Engineering mill inspection report from our 1949 purchase of pipe identical to that used on Line 132 in 1948,[11] our pipe specifications called for the pipe to be subjected to a 90% SMYS hydro test at the mill (~~approximately 1170 psig,~~ which is 1.25 times the MAOP of this pipe <u>if it were operating</u> at 72% SMYS). By design, this test procedure fails critical defects (not all defects), and defects that do not fail are assumed to be safe and stable at the established operating pressure, which is well below the test pressure. As a result of this hydro test being performed, any manufacturing imperfections that remained in the pipe (those that did not fail during the hydro test) would be

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[11] PG&E contracted Moody Engineering Company to inspect the manufacturing process and testing of the Line 132 pipe at Consolidated Western's plant. (Moody Engineering Invoice #8265 (1948) (Ex. 4-17).) While we have not located the final Moody report issued in connection with this specific inspection, we have located the Moody Engineering Inspection Report for pipe ordered approximately three months later from Consolidated Western for Line 153, the specifications for which were identical in every respect to the Line 132 pipe specifications. (Moody Engineering Pipe Inspection Report (1949) (Ex. 4-18); PG&E Pipe Specifications, Line 153 (1949) (Ex. 4-19); PG&E Pipe Specifications, Line 132 (1948) (Ex. 4-20).) Given that the two orders were contemporaneous and that both orders were for the same pipe specification filled by the same manufacturer (and at the same mill inspected by the same engineering company), there is a high degree of confidence that the manufacturing and inspection processes were identical for both pipe purchases.

considered stable and not at risk of growing to failure during the useful life of the pipeline. (See*, e.g.*, John Kiefner, *Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, filed with U.S. Department of Transportation*, (April 2007) ("Kiefner 2007 DOT Report")(Ex. 4-21).)[12] The 1948 construction radiography records therefore do not indicate the presence of an unstable manufacturing threat.

The CPSD report also faults us for not integrating data on longitudinal seam issues identified in Table 2 of the NTSB's Final Report. The pipe involved in those situations was dissimilar to the Line 132 30-inch DSAW pipe and thus they were properly not considered during the integrity assessment of Line 132. For example, the 1958, 1974, 1996, and 1999 longitudinal seam issues identified in Table 2 relate to pipe of a different construction vintage and/or seam type. Any defects identified on these pipelines would not inform the integrity management process for 30-inch DSAW pipe used to construct Line 132. The reference to a long-seam defect on a segment of Line 132 in 1992 is not well-founded, and based upon a misinterpretation of statements made by a Company employee during an NTSB interview.[13] (Telephone Interview with Joe Joaquim, at 6-30 (Ex. 4-22).) Despite a diligent search, we have not located any records that suggest such a defect was ever found or such a repair made on Line 132. Finally, two of the references in Table 2 are to information discovered during testing carried out following the San Bruno accident. Like the accident itself, the information from post-San Bruno testing would not inform pre-San Bruno integrity management decisions, and cannot support CPSD's allegations. Taken together, these data points

[12] This report presents guidelines for evaluating integrity management plans with respect to managing the risk posed by pipe manufacturing and pipeline construction threats. This report considers the effect of pre-service hydrostatic testing, including mill testing of the variety called for in Company pipe procurement specifications, on the stability of manufacturing defects.

[13] In short, the Company employee could not recall the pipeline on which the defect he described was located, thus the conclusion that it was on Line 132 is not supported by his statements.

only reinforce the fact that before September 9, 2010, we had not experienced long seam failures on 30-inch DSAW pipe similar to that used to construct segment 180, and therefore had no reason to consider any segment constructed with this pipe as subject to a potentially unstable manufacturing threat.

Finally, CPSD points to *Integrity Characteristics of Vintage Pipelines,* a report prepared by Battelle Memorial Institute for the INGAA Foundation, as evidence that we should have considered all DSAW pipe as subject to a manufacturing threat. (Clark, E.B., Leis, B.N., and Eiber, R.J., *Integrity Characteristics of Vintage Pipelines*, (October 2004)). However, as reflected in the report, both SSAW and DSAW pipe welds are not particularly prone to anomalies, such as long seam cracks. While there have been isolated occurrences of anomalies, these occurred only in pre-1960 pipe manufactured by Kaiser or U.S. Steel. Consistent with the information in the INGAA report, our Integrity Management program would not have considered pipe manufactured by our principal large pipe supplier of the time, Consolidated Western, as subject to a manufacturing threat.

As reflected in the testimony of Mr. Zurcher, the additional records identified by the CPSD (and NTSB) would not have caused PG&E to consider Line 132 as subject to a potentially unstable manufacturing threat.

d. CPSD Misidentifies Construction Threats as Manufacturing Threats

CPSD cites several examples of purported manufacturing threats identified during the NTSB investigation to support its claim that our data gathering and integration practices were inadequate and should have identified the need to conduct a long seam analysis of Segment 180 and/or 181. The CPSD report refers to a miter bend, leaking girth weld, and wedding band (with the added, unsubstantiated statement that wedding bands are inferior to other pipe appurtenances) as evidence of our faulty data gathering process. (CPSD Report, pp.32-33.) These are examples of construction threats, not manufacturing threats as referenced by CPSD.

The presence of a construction threat has no bearing on the type of integrity management tool chosen to assess Line 132, and does not mandate that we use either hydro testing or inline inspection to assess the pipeline. As discussed in the Kiefner 2007 Report, hydro testing is not capable of identifying or assessing the integrity of construction-related defects. (Kiefner 2007 DOT Report at 2 (Ex. 4-21).) Construction threats do not fail solely due to internal circumferential pressure. Typically, they remain stable unless acted upon by axially-oriented stresses (e.g., the pipe is pulled in opposing directions) or strains related to ground movement. (Kiefner 2007 DOT Report at 16 (Ex. 4-21).) Hydro testing does not impart this type of stress on the pipeline, and would therefore be very unlikely to cause any construction defect to fail. Additionally, in-line inspection tools provide limited information regarding the integrity of girth welds, as the sensors used on magnetic flux leakage tools experience difficulty recording reliable data at girth welds.

In short, construction defects, by their nature, cause the pipeline to be susceptible to damage from movement resulting from outside forces such as an earthquake or landslide. As stated in ASME B31.8S, "[t]he presence of construction-related threats alone does not pose an integrity issue. The presence of these threats in conjunction with the potential for outside forces significantly increases the likelihood of an event. The data must be integrated and evaluated to determine where these construction characteristics coexist with external or outside force potential." (ASME B31.8S, Appendix A § 5.3.) Further, ASME B31.8S provides that "[f]or construction threats, the inspection should be by data integration, examination, and evaluation for threats that are coincident with the potential for ground movement or outside forces that will impact the pipe." (ASME B31.8S Appendix A § 5.4.)

e. PG&E Did Not Exceed Historic Five Year Maximum Operating Pressure, and Did Not Render Any Manufacturing Threat Unstable on Segments 180 and 181

CPSD claims that planned pressure increases we carried out prior to implementation of our Integrity Management program rendered certain manufacturing threats unstable under 49 C.F.R. § 192.917(e)(3). Contrary to CPSD's claim, our 2003 pressure exercise predated the identification of HCAs and the effective date of the integrity management regulations, and therefore could not have exceeded the historic five year maximum operating pressure contemplated by the regulation – the highest pressure experienced during the five years prior to HCA identification. Our 2008 pressure increase on Line 132 did not significantly exceed the pipeline MAOP, or significantly change operating conditions on the line. Therefore, the 2008 pressure did not render any manufacturing threat unstable so as to require a priority integrity assessment of the pipeline longitudinal seam.

(1) PG&E Did Not Identify Its High Consequence Areas Until Implementing Its Integrity Management Plan in December 2004

Section 192.917(e)(3) requires an operator to prioritize for assessment, using a tool capable of identifying seam defects, any pipeline segment that (1) has a manufacturing seam threat, and (2) has been subject to a pressure excursion above the pressure experienced in the five years preceding the date the segment was identified as an HCA segment. (49 C.F.R. § 192.917(e)(3) (also addressing uprated pipe and increased potential for cyclic fatigue).) PHMSA adopted this code section as part of the integrity management rulemaking process that spanned several years starting in 2002. The rulemaking included considerable discussion among pipeline operators and government bodies relating to what factors would determine whether a pipe segment was located in an HCA.

The HCA identification process was not as straightforward as the CPSD report implies. The Research and Special Programs Administration (RSPA), working with the Office of Pipeline Safety (OPS), issued a first "final" rule providing a definition of HCAs for gas transmission pipelines on August 6, 2002. (67 Fed. Reg. 50824 (Aug. 6, 2002).) Just one month later, the American Gas Association, American Public Gas Association, Interstate Natural Gas Association of America, and the New York Gas Group filed a petition for reconsideration of the final rule, pointing out that the rule did not provide a clear definition as to how operators would be expected to identify high consequence area pipeline. (68 Fed. Reg. 69779 (Dec. 15, 2003).) OPS solicited comments on the final definition, particularly with respect to the "identified sites" component of the high consequence area definition. (See *generally*, 68 Fed. Reg. 69779 (Dec. 15, 2003).) While OPS provided guidance on steps it expected operators to take in determining the locations of HCA pipe in an advisory bulletin on July 17, 2003 (68 Fed. Reg. 42456 (Jul. 17, 2003)), it did not issue a final definition of what constituted a High Consequence Area until December 15, 2003 (effective February 14, 2004) – after our 2003 planned pressure increase on Line 132. (See 68 Fed. Reg. 69778 (Dec. 15, 2003), *corrected by* 69 Fed. Reg. 2307 (Jan. 15, 2004) (codified at 49 C.F.R. § 192).)

Prior to issuance of the final rule, we operated Line 132 to approximately 400 psig on December 11, 2003. At that time, we had not and – because the definition of a high consequence area had not been codified in the integrity management regulations – could not have identified any pipeline segment as being within an HCA.[14] We did not formally identify our HCAs until we filed our BAP in December 2004, the time at which the regulations required operators to identify HCAs and a year after the December 2003 pressure increase on Line 132. Filing the BAP satisfied 49 C.F.R. § 192.907(a), which required operators to identify all HCA pipe no later than December 17, 2004. Because we conducted the pressure increase on Line 132 prior to filing our BAP, and prior to issuance of the final rule defining HCA pipe, our planned pressure increase on Line 132 in 2003 did not exceed the historic five year maximum recorded operating pressure on which 49 C.F.R. §

[14] Similarly, 49 C.F.R. § 192.917(e)(3) had not been finalized as of December 11, 2003. Thus, even if we had identified HCA pipelines, the assessment mandates under Section 192.917(e)(3) were not in effect on December 11, 2003, when we raised pressure on Line 132.

192.917(e)(3) is based. Accordingly, we could not and did not trigger the requirement to prioritize any segment on Line 132 for long seam assessment under 49 C.F.R. § 192.917(e)(3).

As discussed more fully in the testimony of Mr. Zurcher, our practice of raising the pressure on transmission pipelines to the MAOP was common within the gas pipeline industry and was considered standard industry practice by many operators. Moreover, the pipeline MAOP contains, by regulatory design, a margin of safety, and there is no operational concern in operating a pipeline up to this value. While we have been criticized for the practice and our interpretation of the regulations (and have permanently stopped the practice), we were by no means alone. Like us, other gas pipeline operators raised the pressure on their pipelines before the PHMSA regulations took effect in 2004 and continued to do so after the regulations took effect. Moreover, it was not uncommon within the industry for readings taken during these planned pressure increases to slightly exceed the MAOP because of measurement tolerances inherent in measuring instruments, including pressure transducers, or pressure gauges. (Zurcher Testimony, Chapter 5, Section (C)(4).)

(2) PG&E's Planned Pressure Increase in 2008 Did Not Trigger a Long-Seam Assessment of Segment 180.

The maximum pressure on Line 132 in 2008 was measured at 400.73 psig. (PG&E's Response to data request NTSB_004-005-Amended (Nov. 5, 2010).) The planned pressure increase would not have been considered to constitute a substantial change in operating conditions that would require the pipeline to be prioritized for assessment. As discussed more fully in the Kiefner 2007 DOT Report at pages 17-21, an increase of such a small magnitude (less than 1 pound over pipeline MAOP on pipeline that has been pressure tested to at least 1.25 times the pipeline MAOP) does not have the capability of rendering stable manufacturing threats on a long seam unstable. Also explained in the Kiefner 2007 DOT Report, even a yearly exceedence of up to 5% over MAOP does not have a substantial effect on the expected life of the pipeline.[15] (Kiefner 2007 DOT Report at 28 (Ex. 4-21).) As described in Chapter 2, we purchased the pipe used to construct Segment 181 in 1948 under specifications that required the pipe to be hydro tested at the mill to 90% of SMYS, well above 1.25 times MAOP, and expected the pipe used in the subsequent 1956 relocation of Segment 180 to be of the same specifications. (See Chapter 2.) Pipe that has been subjected to this kind of strength test (even if the test was carried out at the mill) is not considered to be at risk of failure during the conceivable life of the pipeline. Additionally, pipe that experiences a yearly pressure excursion that exceeds MAOP by five percent does not have its time to failure meaningfully diminished. Thus, applying John Kiefner's analysis to Line 132, even a 20-pound excursion (equivalent to 5% over the 400 psig MAOP) would not be substantial enough to render a manufacturing threat unstable.

We recognize that the Kiefner DOT 2007 Report stands in conflict with PHMSA FAQ (Frequently Asked Question) 221 with regard to the amount to which a pressure excursion must exceed the five year historic MOP in order to trigger the provisions in Section 192.917(e)(3). FAQ 221 states that any increase – no matter how small – would require prioritization of the segment for assessment. However, PHMSA FAQs are non-binding regulatory interpretations by staff that, like FAQ 221, often contain little, if any technical justification or support. The Department of Transportation, OPS-sponsored Kiefner Report, on the other hand, was the product of extensive technical investigation and rigorous

[15] On HCA segments where we had raised pressure on a planned basis above the pipe segment MAOP, we have analyzed the segment to determine the risk of failure from these defects pursuant to 49 C.F.R. § 192.917(e)(3). This analysis, called an Engineering Critical Assessment (ECA), evaluates whether latent manufacturing defects have become unstable and would further require an integrity assessment (in-line assessment or hydro test). The ECA considers prior hydro tests that can demonstrate the stability of the pipeline. Depending on the magnitude of the pressure increase and previous hydrostatic pressure test, the segment may still be considered stable even in the event of an over-pressurization.

scientific testing, analyzing the real world effects of pressure changes on pipelines and their susceptibility to pressure excursions and cyclic fatigue. The Kiefner 2007 DOT Report's conclusion that such a small pressure variation would not render a stable manufacturing threat unstable provides a sound basis for treating a less than one pound exceedence (less than 0.25% of MAOP) as inconsequential.[16]

3. PG&E Appropriately Evaluates Cyclic Fatigue Threats in Its Integrity Management Program

CPSD asserts that we violated 49 C.F.R § 192.917(e)(2). That section provides in relevant part:

> "(e) *Actions to address particular threats*. **__If__** an operator identifies any of the following threats, the operator must take the following actions to address the threat.
>
> ". . .
>
> (2) *Cyclic fatigue*. An operator must consider whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. . . ." (Italics in original; bold and underline added.)

CPSD alleges that we dismissed cyclic fatigue without analyzing its effect on all our transmission lines, and particularly for line segments that had not undergone hydrostatic testing per Part 192, Subpart J. CPSD also alleges that we did not incorporate cyclic fatigue into our segment-specific threat assessments and risk ranking algorithm in either our 2005 or 2010 Integrity Management Protocol Matrices. CPSD's arguments, however, are made with the benefit of hindsight provided by the San Bruno accident where we now know that a missing interior weld combined with a ductile tear likely caused by a field hydro test was exacerbated by 50 years of fatigue

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[16] Given the imprecision of the pressure measuring equipment, we cannot be certain if the 0.73 psig is real or a measurement artifact.

crack growth to the point where a pressure less than the MAOP of the pipe caused the seam to rupture. (Caligiuri Testimony, Chapter 3.)

Before San Bruno, we, like other gas transmission pipeline operators, concluded that cyclic fatigue was not a threat to our gas transmission pipeline and reflected this view in our Integrity Management program. We did, however, participate in further research into the potential threat, providing operating data in support of Mr. Kiefner's efforts to analyze the effects of cyclic fatigue on gas pipelines in particular and to offer operators more concrete industry guidance on how to address the threat. This effort led to the publication of Kiefner's 2007 DOT Report.

Even a comprehensive analysis of Line 132, Segment 180 using the framework and calculations set forth in Kiefner's 2007 DOT Report would have determined that cyclic fatigue did not present a significant threat to the segment during the useful life of the pipeline.

a. Prior to the San Bruno Incident, the Gas Pipeline Industry Understood the Threat of Failure of Gas Pipelines Due to Cyclic Fatigue to be Negligible

Cyclic fatigue, the progressive structural damage that occurs when a pipeline is subjected to fluctuating pressure cycles, presents a considerable threat to the integrity of liquid-transport pipelines. In contrast to liquid-transport pipelines, prior to San Bruno, operators believed that natural gas transmission pipelines were at a substantially reduced risk for cyclic fatigue. Natural gas pipelines do not experience anywhere near the magnitude or frequency of pressure-cycle variations that liquid pipelines experience. This is largely due to the fact that, unlike liquid petroleum, natural gas is compressible in nature. Because natural gas is compressible, changing operating conditions (e.g., increased quantities of product in the pipeline) do not cause the pressure in a gas pipeline to change as severely or as rapidly as do fluctuating conditions in liquid pipelines. In liquid pipelines, pressure swings from 0 psig to pipeline MAOP are common; natural gas pipelines rarely experience such swings, and tend to consistently operate within an established range, rarely (if ever) dropping to zero psig during normal operation.

This view of the limited risk of cyclic fatigue in gas pipelines was supported by a 2004 report by John Kiefner and Michael Rosenfeld, two of the leading technical experts in the natural gas pipeline industry.[17] And the 2007 DOT-sponsored report by Kiefner (referenced above) underscored that, prior to the San Bruno incident, cyclic fatigue was not considered to be a common threat to gas transmission pipelines, particularly for pipe segments subjected to a hydro test reaching at least 1.25 times the pipeline maximum operating pressure. (Kiefner and Rosenfeld, *Effects of Pressure Cycles on Gas Pipelines Final Report*, at p. 15 (Sept. 17, 2004) ("Kiefner and Rosenfeld 2004 Report"), (Ex. 4-23).) In his testimony here, Mr. Kiefner provides historic background into the inclusion of cyclic fatigue in the federal gas pipelines regulations and further explanation for the reason that, prior to San Bruno, the natural gas industry considered cyclic fatigue to be a negligible threat to gas pipelines. (Chapter 6.)

During the integrity management rulemaking process, pipeline operators and regulators spent a considerable amount of time and energy exploring ways to minimize the risk posed by external corrosion since it is considered a majority threat that essentially exists on all steel pipelines. In contrast, other minority threats such as manufacturing, construction, and cyclic fatigue received limited attention. As reflected in the testimony of Mr. Kiefner, prior to San Bruno, it was well accepted in the gas pipeline industry that cyclic fatigue did not present a significant threat to natural gas pipelines.

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17 In addition to the Kiefner and Rosenfeld's reports, an August 10, 2009 Pipeline and Hazardous Materials Safety Administration (PHMSA) letter to the National Transportation Safety Board regarding Safety Recommendation P-04-01 presented the results of a PHMSA analysis that indicated: (1) "Typically, gas pipelines are not at significant risk of failure from the pressure-cycle-induced growth of original manufacturing-related or transportation-related defects;" and (2) "PHMSA records do not contain any known incidents involving failure of steel natural gas transmission pipe from the pressure-cycle-induced growth of original manufacturing-related or transportation-related defects." (Ex. 4-28).

b. PG&E Appropriately Considered the Threat of Cyclic Fatigue on Its Transmission Network.

In 2005, we told PHMSA and CPSD in writing that cyclic fatigue was "not considered a threat due to the level of increases and frequency of pressure increases in our system." (Audit Protocol Matrix (2005) at 12 (Ex. 4-24).) We made this disclosure in an audit protocol matrix we sent to CPSD to facilitate its audit of our Integrity management program that year.[~~17~~18] CPSD did not take issue with our position and it was never raised to our attention as a perceived violation. (Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety, Gas Integrity Management Inspection Manual: Inspection Protocols with Results Forms, at 31 (July 1, 2005) (Ex. 4-25).)

Our (and the natural gas industry's) conclusion regarding the likelihood of cyclic fatigue impacting our pipelines prior to the San Bruno incident was consistent with ASME B31.8S. Section 2.2 notes that "[h]istorically, metallurgical fatigue has not been a significant issue for gas pipelines." (ASME B31.8S § 2.2.) Our consideration of the likelihood of cyclic fatigue was also consistent with the findings of industry experts Kiefner and Rosenfeld's 2004 report on the effects of pressure cycles on gas pipelines. (Kiefner and Rosenfeld 2004 Report (Ex. 4-23).) Kiefner and Rosenfeld's 2004 Report found that the predicted times to failure due to cyclic fatigue in most gas pipelines were from 170 to 400 years, and therefore that gas pipelines were not at significant risk of failure from the pressure-cycle-induced growth of seam defects. "Therefore," the report concluded, "there is no need in general, to conduct periodic integrity assessments of gas pipelines from the standpoint of pressure-cycle-induced fatigue in seams." (Kiefner and Rosenfeld 2004 Report. at 16 (Ex. 4-23).)

[~~17~~18] An audit protocol matrix is an internal PG&E document that we develop prior to regulatory audits as a review tool to identify the specific sections of our RMPs setting forth the procedures and policies that are the subject of the PHMSA audit protocol used by CPSD in its audits. In essence, our audit protocol matrix serves as a roadmap for the auditors to review and evaluate our integrity management procedures and policies.

Subsequently, Kiefner's 2007 DOT Report provided further support for our (and the industry's) belief that transmission pipelines were not at risk of failure due to cyclic fatigue during the conceivable life of the pipeline. Accordingly, in the 2010 audit protocol matrix we provided to CPSD for its May 2010 audit of our Integrity Management program, we again documented this conclusion, stating that cyclic fatigue and other loading conditions are "[n]ot considered a threat due to size and frequency of pressure increases in our system. Reference INGAA/Kiefner paper." (Audit Protocol Matrix (2010) at 6. (Ex. 4-26).) Similar to 2005, this was not brought up by the CPSD as a concern at that time.

c. Application of the Analysis in Kiefner's 2007 DOT Report Does Not Identify Segment 180 as Susceptible to Cyclic Fatigue During its Useful Life

The CPSD report alleges that we should have concluded that Segment 180 was at risk of failure due to cyclic fatigue by application of the calculations and analysis in the Kiefner 2007 DOT Report. However, the CPSD report does not properly apply the analysis from Kiefner's 2007 DOT Report to the Segment 180 pipe specifications (either seamless, as was reflected in the Company's GIS, or DSAW, as called for in original records from the 1956 relocation job file). Applying Mr. Kiefner's analysis, the DSAW pipe specified for use in Segment 180 would have had an expected useful life of approximately 96 to 111 years. This is explained in further detail in the testimony of Mr. Kiefner. (Kiefner Testimony, Chapter 6 at 6-5 to 6-6.)

4. PG&E Maintains an Appropriate Risk Assessment Model

CPSD claims several deficiencies in our risk assessment model as it existed on September 9, 2010. While the federal code requirements relating to risk assessment are provided in 49 C.F.R. § 192.917(c), CPSD does not assert that any of the alleged deficiencies in our RMPs rise to the level of violations. The lack of identifiable violations demonstrates that the alleged deficiencies are more appropriately viewed as differing viewpoints of subject matter experts and the recognition by regulators that integrity management programs (and thus, risk assessment models) are an evolving process. As reflected in the expert testimony of Mr. Zurcher, our risk assessment model, which incorporated both incident-related data and guidance provided by company subject matter experts on the various risks, is consistent with regulatory requirements. Even if our risk assessment algorithms are deemed somehow deficient, such deficiencies would not have changed our Integrity Management program's treatment of Line 132, and Segment 180.

a. PG&E's Risk Assessment Model Satisfied Regulatory Requirements

Risk assessment models enable operators to assess the relative risk associated with the operator's pipelines and prioritize higher risk pipelines for assessment in the operator's integrity management program. As noted in ASME B31.8S, section 5.4, risk assessment models are not an exact mathematical calculation, but "should be used in conjunction with knowledgeable, experienced personnel (subject matter experts and people familiar with the facilities)" in order to make the appropriate relative risk determinations. Additionally, federal regulations reflect an awareness that risk assessment models would evolve over time based on incorporation of information learned through operation of the system. (See*, e.g.*, 49 C.F.R. §§ 192.907(a) and 192.911.)

Our risk assessment model is based on the experience and expertise of our subject matter experts and multiple threat committees, which is consistent with ASME B31.8S, section 5.4, and which may result in risk model approaches that differ from other reasonable views. (See also See Penspen Integrity, *Overview of PG&E's Pipeline Risk Management Procedures (01 – 05)*, p. 35 (Nov. 15, 2010 Draft) (Penspen Draft Audit).) As Mr. Zurcher concludes in his testimony, our risk assessment model is consistent with the regulatory requirements in 49 C.F.R. § 192.917(c). In a Company-initiated 2010 audit of our Integrity Management program performed by Penspen Integrity, the consultant concluded that our risk assessment model was in compliance with federal regulation and industry consensus standards.

b. The Alleged Deficiencies in the Risk Assessment Model Did Not Contribute to the San Bruno Incident

Even if our risk assessment model were deemed somehow deficient, any deficiencies did not have a detrimental effect on our Integrity Management program's assessment of Line 132, and Segment 180. Whereas the threat identification process is a yes/no determination of whether pipeline specifications, operating conditions and maintenance history demonstrate the presence of one or more of several enumerated threats, risk assessment is a prioritization that determines *when* a pipe segment will be assessed, *not whether* or, perhaps more importantly, *how* it will be assessed. Pursuant to our risk ranking algorithm, Line 132, Segment 180 was prioritized for assessment to be completed in the first half of the Integrity Management program's 10-year BAP, consistent with the regulatory directive to assess the highest risk pipe segments by December 17, 2007. Neither the timing nor the methodology for the Integrity Management assessment of Segment 180 was altered by the weaknesses CPSD claims with respect to our risk ranking algorithm.

c. Specific Risk Algorithm "Deficiencies" Cited by CPSD are Reasonable Differences in Opinion Between Subject Matter Experts

Given the evolving level of expertise in the industry and among regulators, according to Penspen Integrity's audit, "disagreement, or missing data, does not mean our risk algorithm is deficient; it merely highlights differences in how an expert team view[s] the risks associated with their own pipeline, compared to a generic standard (ASME B31.8S). Any 'missing' data may still have been included in the risk assessment process of the team." That is to say, missing documentation of our decisions regarding the calculations underlying these particular risk algorithms does not mean that our decision is unjustified. As explained in Mr. Zurcher's testimony, the purported deficiencies CPSD identified are more properly characterized as reflecting subjective views and recommendations as to best practices, rather than objective failures to conform to standard industry practices or operators' general understanding of the requirements of 192.917(c).

Although our risk assessment model meets regulatory requirements, we acknowledge CPSD's specific recommendations (addressed individually below) with respect to our risk assessment model and will carefully consider them. We are committed to assuring that our risk assessment model meets or exceeds all regulatory requirements and continually evolves, consistent with regulatory intent. We also strive to incorporate good industry practice (even when it is not required by regulations),[~~18~~19] and are currently implementing many improvements (as discussed section E).

First, CPSD criticizes the weighting factors applied in our risk ranking algorithm because they reflect industry experience, rather than our incident history. However, as set forth in ASME B31.8S, section 5.7(i), "such factors can be based on operational experience, the opinions of subject matter experts, or industry experience." Thus, our reliance on industry experience in establishing weighting factors was consistent with ASME B31.8S.

With regard to CPSD's criticism of the default values in our External Corrosion Threat Assessment algorithm (RMP-02), currently, industry operators must follow the general guidance that an "operator should choose default values that conservatively reflect the values of other similar segments on the pipeline or in the operator's system." (ASME B31.8S § 5.7.) Because industry guidance does not establish specific default values, operators are also cautioned against using excessively conservative default assumptions that could prioritize the operator's integrity management efforts toward a falsely prioritized threat and away from threats the present a greater risk. (Rosenfeld, *Data Gaps in Pipeline Risk Assessment and the Role of ASME Codes and Standards*

[~~18~~19] Prior to San Bruno, we had retained consultants to review and evaluate our risk assessment methodology. In 2005 and 2007, we retained Process Performance Improvement Consultants, LLC (P-PIC) to audit our integrity management framework, including our risk assessment model. We retained WKMC, LLC to conduct similar evaluations in 2009 and 2010. Additionally, in 2010 we retained Penspen Integrity to perform an audit of our Risk Management Procedures. Collectively, these audits noted that we met (and, at times, exceeded) existing regulatory requirements.

(presented at PHMSA Workshop) (Jul. 11, 2011) (Ex. 4-27).) Thus, our use of values other than the most conservative in its external corrosion algorithm is a proper application of default values that properly prioritizes the threats potentially present on our pipelines.

CPSD also criticizes our Third Party Damage Algorithm (RMP-03) for not specifically taking into account one-call ticket frequency. We are addressing CPSD's recommendation and currently revising our Third Party Damage Algorithm to incorporate one-call ticket frequency. We expect to complete the revisions later this year and publish the results in the first quarter of 2013 as part of our 2012 risk evaluation. The process of integrating one-call ticket frequency into our risk assessment model includes significant data integration given the large number of one-call tickets that could potentially affect a natural gas transmission pipeline.

Finally, CPSD criticizes our Design Materials Threat Algorithm (RMP-05) because the percentages associated with the factors the algorithm takes into account (factors A-G) appear to add up to 120%. As noted in the introduction to the pertinent section of RMP-05, only factors A-F are significant to determining likelihood of failure, which weightings total 100%. (See RMP-05 at 6 (Ex. 4-5).) The additional factor G – "Test Pressure vs. Pipe Strength" – serves to factor in as a risk mitigation credit in pipes that have been pressure tested (that is, factor G can work to lower the risk by up to 20%), consistent with ASME B31.8S, section 5.7(c), which states that "the risk assessment method shall account for any corrective or risk mitigation action that has occurred previously." Thus, the design materials threat algorithm is not a fixed, one time, calculation but may vary depending on the risks that have been mitigated through other efforts, such as a hydro test or other integrity management activities.

D. PG&E Properly Selected External Corrosion Direct Assessment for Line 132, Including Segment 180

As described in detail in this chapter, our Integrity Management program gathered the proper data and conducted threat identification for Line 132, Segment 180 consistent with ASME B31.8S and the federal integrity management regulations. Through the data gathering and threat identification process, we identified external corrosion as the primary threat to Segment 180 (and 181), and consistent with the integrity management rules and our Integrity Management procedures, concluded that external corrosion direct assessment was the appropriate assessment methodology to use.

Prior to San Bruno, we (and the industry as a whole) considered DSAW pipe to be equivalent to seamless pipe in terms of reliability and risk, as reflected by its joint efficiency factor (1.0) and its absence from the categories of pipe flagged in ASME B31.8S as potentially being subject to manufacturing threats. While our records erroneously identified the pipe in Segment 180 as seamless, this had no effect on the integrity management assessment method chosen for the pipeline. We had no reason to believe that any potential manufacturing defect on Segment 180 was rendered unstable by the common industry practice of operating certain pipelines to MAOP once every five years. Our determination that cyclic fatigue was not a threat to our pipelines was well supported by industry experience and scientific analysis. Finally, our risk ranking algorithms, while undergoing improvements based on CPSD recommendations, met regulatory requirements and more importantly had no impact on how Line 132, Segment 180 was assessed.

With the knowledge we have today that three of the pups in Segment 180 were missing interior welds, we would ~~conduct an integrity management assessment of Line 132 capable of determining the presence of longitudinal seam defects~~have replaced that section of pipe. . But, we had no basis to determine we should do so prior to September 9, 2010. Rather, our Integrity Management program followed regulatory requirements and industry consensus standards in carrying out external corrosion direct assessment on Line 132 and Segment 180. Direct assessment was the appropriate assessment method called for by the integrity management regulations and our Integrity Management procedures.

E. PG&E's Initiatives to Make Its Integrity Management Program Better

Even though our Integrity Management program addressed the risks posed to Segment 180 (and 181) properly given our records and regulatory direction, we are reassessing every aspect of our Integrity Management program to identify those areas where we can improve.

At the core of this effort is a major restructuring of the organization and personnel responsible for implementing our Integrity Management program. We have established a team solely dedicated to transmission integrity management.[~~19~~20] We hired consultants recognized and respected in the industry as experts in integrity management to assist in an in depth review of the program policies, procedures and tools. This review was conducted in close coordination and collaboration with the Company in order to assure that our updated Integrity Management program meets all regulatory requirements, utilizes industry accepted practices, and integrates technical knowledge and experience from outside consultants to best improve both public safety and system reliability. Concurrently with this comprehensive review, we have taken and continue to take several additional actions to further improve our Integrity Management program.

Recognizing that our RMPs and risk ranking algorithms could be refined, we updated our risk assessment model and RMPs in connection with our 2011 BAP. Revisions included changing the weighting of the risk factors for the existing threats to better reflect risk and threats related to long seam information and incorporation of additional historical leak records that have been identified through our MAOP Validation effort. We ~~are in~~have completed the process of further refining our risk model with respect to stress corrosion cracking, internal corrosion, equipment, and incorrect operations. These revisions ~~are expected to be~~were completed in 2012 and the results will be published in the first quarter of 2013 as part of our 2012 risk assessment.

As noted, we are also reviewing and updating the RMPs that comprise the Integrity Management program. Based upon recommendations received from our consultants and other relevant stakeholders, we ~~will be updating~~planned to

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[~~19~~20] Previously, in addition to their integrity management roles, our integrity management personnel may also have had job duties related to pipeline engineering that did not necessarily involve integrity management. Also, with the introduction of distribution integrity management regulations, some aspects of both programs were previously addressed by the same personnel. Both integrity management programs are still under the umbrella of one Vice President, but now have dedicated Director level led teams for program oversight and implementation.

update almost every procedure in our Integrity Management program. ~~Several have been updated already, and the majority of this work is expected to be completed in 2012.~~We have implemented this plan, and all of our RMPs have been revised. However, we expect to have additional updates to our RMPs in 2013 as a part of our continuous improvement efforts.

We are focused on improving the data gathering and integration component of our Integrity Management program. A key initiative included in our Pipeline Safety Enhancement Plan (PSEP), submitted to the Commission on August 26, 2011, is the Gas Transmission Asset Management Plan (GTAM), now called Project Mariner. Through Project Mariner, we will substantially enhance our integrity management process in several ways, including: increasing the amount, types and quality of information collected and maintained electronically regarding our pipelines; improving the systems for collecting, validating and retaining pipeline data; increasing the traceability of materials used in the construction and maintenance of transmission pipelines; and enhancing our ability to assess and mitigate potential public safety risks. By establishing a better technology infrastructure to support integrity management processes, we expect to improve and maintain data reliability and enable better decision-making related to the risks and integrity of our gas transmission system. In addition, through our MAOP validation effort, we are building detailed pipeline features lists down to the individual component level for all of our transmission pipelines. The final product will become the foundation of historical asset information on which Project Mariner will be based.

The primary aspects of Project Mariner that will directly benefit our Integrity Management program include:

- All asset data, including location, specifications/features, and maintenance/inspection history, will be tracked, managed, and stored using a software product and data management technique called linear referencing, a modern best practice for viewing and analyzing pipeline features, characteristics, and event history relative to specific reference points along the length of a gas transmission pipeline.
- Materials will be tracked in a traceable chain from receipt by the Company through the operating life of the component. Key information and features

to be tracked will include the manufacturer of the asset, characteristics of the component, manufacturer ratings, and factory test results.

- Work management and data capture pertaining to maintenance and inspection processes (including Locate and Mark and Leak Survey) will be more efficient, accurate, timely, and complete. This will be accomplished by eliminating paper-based maintenance and inspection work processes and implementing automated work processes that will manage Leak Survey, Locate and Mark, and preventative/corrective maintenance from scheduling the work, capturing information from the field, and verification and quality review of the data.
- System tools will enable integration of all underlying asset data, including event history such as leaks, dig-ins, etc., to provide a comprehensive picture of asset condition with ability to perform risk and integrity analytics.

The implementation schedule for this extensive project is in four phases, over a period of approximately 3.5 years (fourth quarter of 2011 through first quarter of 2015). In advance of the project, we are in the process of converting all paper records and databases documenting gas transmission leak history to a single electronic database, including paper documents that identify and report historical weld seam leaks. The database is targeted for completion later this year.

We are also addressing threat identification. We hired consultants to assist in creating new threat identification procedures related to manufacturing threats, construction threats, internal corrosion, stress corrosion cracking, fatigue (including cyclic fatigue) and interacting threats. Our consultant developed the procedures and analysis tools for manufacturing, construction, and interacting threats, which ~~we will incorporate~~were incorporated into our Integrity Management program in 2012. We will also be integrating updated threat identification procedures related to the other described threats into our Integrity Management program.

We are taking steps to ensure that the improvements identified and implemented following the San Bruno accident result in a fully effective and compliant Integrity Management program. To that end, we directed our consultant to specifically evaluate all performance aspects of our Integrity

Management program. The consultant will provide recommendations for improving our self-assessment metrics that are used internally to evaluate whether our Integrity Management program is effectively assessing and evaluating the risk, threats and integrity of each covered pipeline segment. Our consultant will be issuing these recommendations in 2012, and we expect to implement them starting this year.

Through all of these initiatives, we are actively taking steps to improve our Integrity Management program from top to bottom. The improvement efforts identified above address CPSD's recommendation nos. 2-6; 8-13; and 41(f) and 42(g). We have embarked on a complete assessment of every aspect of our transmission Integrity Management program. Many improvements have already been made and several others are planned and in progress. This review will assure that our Integrity Management program meets or exceeds all regulatory requirements, incorporates good industry practice, and reflects all lessons learned from San Bruno.