PREPARED DIRECT TESTIMONY OF MARCEL HAWIGER

CALIFORNIA PUBLIC UTILITIES COMMISSION

INVESTIGATION OF THE SAN BRUNO EXPLOSION AND FIRE

OII 12-01-007

on behalf of

THE UTILITY REFORM NETWORK

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Pursuant to the schedule established in the Joint Scoping Memo and Ruling of March 13, 2012, as modified by ALJ Wetzell on April 6, 2012 and April 23, 2012, I am submitting this testimony on behalf of the Utility Reform Network ("TURN").

I have been a staff attorney at TURN since August of 1998. I have participated in many gas proceedings and utility rate cases, including the "Gas Accord" proceedings concerning PG&E's gas transmission and storage departments. I have testified previously before this Commission. My statement of qualifications is included as Attachment 1.

1. SUMMARY OF RECOMMENDATIONS AND CONCLUSIONS

1. The deficiencies and violations related to PG&E's Transmission Integrity Management Program ("TIMP")[1] identified in the CPSD and NTSB Reports[2] appear to reflect system-wide problems. The Commission should either expand this Investigation or open a new Investigation to determine the full scope of PG&E's Integrity Management violations and deficiencies. A more comprehensive investigation of PG&E's past Integrity Management practices would likely show more deficiencies affecting a broader scope of PG&E's HCA pipeline.

[1] Transmission Integrity Management refers generally to procedures and practices adopted to comply with the 2002 Pipeline Safety and Improvement Act and regulations in Subpart O of 49 CFR 192.

[2] This testimony refers extensively to two reports. Consumer Protection and Safety Division, "Incident Investigation Report," January 12, 2012 ("CPSD Report"); and National Transportation Safety Board, Accident Report, NTSB/PAR-11/01, August 30, 2011 ("NTSB Report").

2. Such a comprehensive investigation should include an evaluation of the results of PG&E's Maximum Allowable Operating Pressure ("MAOP") Validation Project, which is included as part of PG&E's Pipeline Safety Enhancement Plan ("PSEP"), to determine whether record-keeping deficiencies and/or errors in database input resulted in the misidentification of pipeline threats under PG&E's Integrity Management Program.

3. Even absent such a comprehensive examination of PG&E's past practices with respect to Integrity Management, the available information provides substantial evidence of Integrity Management deficiencies extending well beyond Line 132, including:

a. At the start of its Integrity Management Program in 2004, PG&E ruled out hydrotesting as an assessment method and, from 2002-2010, PG&E in-line inspected 171 miles of HCA pipeline, thus failing to properly assess the vast majority of its HCA pipeline for manufacturing or construction defects.

b. PG&E in 2004 identified 457 miles of HCA pipe with a manufacturing threat, but conducted in-line inspections on only 34.35 miles of this pipe during 2004-2010, including only 10.41 miles using TFI pigging. Thus, for almost all of this pipeline, PG&E failed to use the proper assessment method.

c. From 2003-2010, PG&E spiked over 415 miles of pipeline, including 86 miles of pipeline identified as having a manufacturing threat (a subset of the 457 miles identified above). PG&E should have hydrotested these 86 miles of pipeline for priority assessment of seam threats.

4. The findings and conclusions above have implications for the issue of ratepayer versus shareholder cost responsibility for PG&E's Pipeline Safety Enhancement Plan ("PSEP"), filed in Rulemaking 11-02-019. In light of PG&E's own principle that its shareholders should be responsible for work that should have been done under existing regulations,[3] the Commission should make the following findings:

a. Of the 457 miles of pipeline discussed in 3.b above, 239 miles are scheduled for testing and 62 miles for replacement under PG&E's Phase 1 PSEP.[4] If PG&E had properly assessed this pipeline under Integrity Management requirements, PG&E should have already tested or replaced this pipeline.

b. Of the 86 miles of pipeline discussed in 3.c above, 51.7 miles are scheduled to be tested (31.9 miles) or replaced (19.8 miles) in PG&E's Phase 1 PSEP. If PG&E had properly assessed this pipeline under Integrity Management requirements, PG&E should have already hydrotested this pipeline.

c. A more comprehensive Commission investigation of PG&E's past Integrity Management practices would likely show more miles of pipeline that are scheduled to be tested or replaced in PG&E's Phase 1 PSEP that should have already been tested or replaced if PG&E had fulfilled its obligations under Integrity Management regulations.

4. The Commission should investigate whether PG&E should have known that more pipeline segments than just Segment 180 were defective. To support this investigation, the Commission should order PG&E, at shareholder expense, to have

[3] R.11-02-019, Exhibit 21 (Bottorf Rebuttal Testimony for PG&E), pp. 1-1 to 1-2.
[4] The Phase I of the PSEP includes the specific request made by PG&E to fund pipeline testing and replacement work scheduled for 2012-2014. The PSEP was submitted by PG&E on August 26, 2011 in R.11-02-019.

independent and experienced pipeline inspectors present during all excavations conducted as part of testing or replacement in the PSEP. These inspectors should monitor the condition of the existing pipe to evaluate the presence of pre-existing defects.

2. SUMMARY OF CPSD FINDINGS REGARDING INTEGRITY MANAGEMENT ON LINE 132

Section V of the CPSD Report, entitled "Integrity Management," describes several deficiencies in PG&E's integrity management procedures that contributed to the rupture of Segment 180. The CPSD Report includes the following facts concerning PG&E's data gathering, threat identification and risk assessment:

- PG&E failed to gather all relevant leak data on Line 132 and integrate it into the GIS system used for risk analysis. PG&E failed to integrate relevant data from the 1948 construction records, and data on seam leaks and test failures from other similar DSAW pipe.[5] These data would have confirmed the potential for a manufacturing defect on Segment 181 and would have resulted in a different and more appropriate assessment method choice.
- PG&E did not ensure the use of conservative default values in the absence of reliable data. PG&E used several non-conservative values, non-conservative assumptions (concerning pipe characteristics), and did not consider all relevant information (missing girth weld radiography records, construction damage, leaks on similar pipelines, use of "wedding band"

[5] CPSD Report, pp. 32-34, 46-47.

joints) in its risk assessment process, as required by Part 192.917(c)[6] and ANSI B31.8S.

- PG&E failed to analyze cyclic fatigue and loading conditions in its threat assessment of Line 132. PG&E excluded the threat of cyclic fatigue based on the results of a 2007 report by John Kiefner without conducting any evaluation or analysis, using the actual pressure spectrum of Line 132, as required by Part 192.917(e)(2).[7]
- PG&E spiked the pressure on Line 132 in December 2003 over the system MOP within days of identifying the pipeline as an HCA location in order to argue that any future pressure increases would not exceed the "maximum operating pressure experienced during the five years preceding identification of the high consequence area," thus triggering a finding of an unstable defect pursuant to Part 192.917(e)(3).[8] PG&E repeated the pressure spiking in 2008.

As a result of these deficiencies, PG&E failed to properly identify and properly assess all potential threats on Line 132. PG&E was required to assess all pipeline threats. For pipelines where PG&E identified manufacturing threats, PG&E had to properly

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[6] All references are to Section 49 of the Code of Federal Regulations unless otherwise indicated.

[7] CPSD Report, p. 50-54.

[8] CPSD Report, p. 43. The CPSD Report goes to great lengths to document that the "pressure spikes" were actually performed a few days *after* identification of the segments as located in an HCA. Regardless of the actual timing, it is clear that PG&E's intent with the pressure spiking was to avoid any possibility of a future pressure increase that would trigger the need to consider an operating or manufacturing threat as unstable.

assess the threat. Guidance for assessing manufacturing threats is provided in 49 CFR 192.917 and ASME/ANSI B31.8S, Section 5.

The CPSD report includes an analysis of "specific errors in PG&E's threat analysis and how that impacted Line 132."[9] The CPSD Report relies in large part on the facts and data in the NTSB Report as support for these conclusions. The factual conclusions contained in the NTSB Report focus on Line 132, and more specifically Segment 180 and surrounding pipeline segments. While the NTSB Report considered voluminous data from various sources, it was focused on the rupture of Line 132.

The CPSD Report concludes that:

> Had PG&E properly identified the threat of potentially unstable manufacturing defects, it would have been required to use an assessment technology capable of assessing this threat. Had PG&E hydro-tested Segment 180, it is highly probable that one of the defective pups would have failed.[10]

The CPSD concludes that PG&E should have, at the very least, hydro-tested adjoining Segment 181, and would thus have found the defects on Segment 180.

The evaluation of PG&E's practices with respect to integrity management indicates that PG&E did not perform the type of thorough records-based review of all available data concerning Line 132 that was required under federal regulations in order to properly identify all threats. Where data deficiencies or shortcomings were present, PG&E did not make proper conservative assumptions. PG&E did not consider available information that would have resulted in different threat identification. The outcome was that PG&E relied exclusively on external corrosion direct assessment ("ECDA") to assess

[9] CPSD Report, p. 38.
[10] CPSD Report, p. 26.

the threats on Line 132. ECDA was incapable of detecting the type of seam threats that existed on Line 132.

3. NEED FOR SYSTEM-WIDE INVESTIGATION OF INTEGRITY MANAGEMENT PRACTICES

The NTSB and CPSD Reports are focused on PG&E's Integrity Management violations as they relate to the San Bruno pipeline and explosion. The findings and conclusions in these Reports raise questions regarding: (1) the extent to which the identified Integrity Management violations affected other pipeline segments; and (2) whether a more comprehensive investigation of PG&E's Integrity Management practices would show other violations.

It is likely that the Integrity Management violations that resulted in deficiencies in PG&E's assessment of Segment 180 on Line 132 affected other HCA pipeline. The types of deficiencies identified in the NTSB and CPSD Reports reflect broad, system-wide issues that appear not to be limited to Segment 180. For example, CPSD points out a faulty PG&E policy that caused it to fail to gather the necessary data, such as leak history data, for threat assessment.[11] Similarly, the NTSB and CPSD Reports find multiple instances in which PG&E failed to follow the requirement to use conservative assumptions when performing risk assessment.[12] Other likely broad-based problems include: processes that did not ensure accurate information in PG&E GIS system,[13] PG&E's failure to consider certain pipeline characteristics and maintenance information

[11] CPSD Report, p. 30 (PG&E's policy in RMP-06 is contrary to applicable regulations).
[12] CPSD Report, p. 31; NTSB Report, Sec. 2.6.1.
[13] CPSD Report, p. 32.

in its threat algorithms,[14] PG&E's failure to consider DSAW pipe as potentially subject to manufacturing defects,[15] and PG&E's failure to appropriately consider cyclic fatigue in its threat assessment and risk ranking processes.[16] The NTSB concluded that "PG&E's pipeline integrity management program was deficient and ineffective."[17] The NTSB recommended a comprehensive audit of PG&E's integrity management programs (P-11-22), and recommended that PG&E "assess every aspect of your integrity management program." (P-11-29)

Accordingly, TURN urges the Commission to either expand this investigation or to open a new investigation in order to conduct a comprehensive assessment of PG&E's past Integrity Management practices. These and other system-wide deficiencies in PG&E's Integrity Management Program need to be investigated to determine the full scope of PG&E's violations and to fully inform the Commission's determination of necessary remedies. While this Commission is comprehensively addressing PG&E's past record-keeping and pipeline classification practices in other dockets, there is no such systematic evaluation for Integrity Management. The extent to which deficiencies in PG&E's integrity management practices affected other pipeline segments is important for future system safety.

Moreover, an evaluation of deficiencies in PG&E's past integrity management practices could provide valuable information to assist PG&E in future threat identification and assessment. One of the issues that should be addressed going forward is how to properly assess manufacturing threats, especially on non-HCA pipeline. TURN is

[14] NTSB Report, Sec. 2.6.1.
[15] CPSD Report, pp. 41-42.
[16] CPSD Report, pp. 50-54.
[17] NTSB Report, p. xi and 114.

concerned that, in an understandable desire to ensure safe pipeline operations, this Commission may have moved too quickly in mandating testing or replacement of *all* pipeline, including non-HCA pipeline, where PG&E is missing complete historical test records. The Commission should consider whether other options could provide the same assurance of safety at lower cost. It is possible that a properly conducted integrity management program may be sufficient to address threats existing on some pipeline segments for which MAOP was established pursuant to the grandfathering provision of 192.619(c). While federal gas Transmission Integrity Management Plan regulations apply only to HCA pipeline, the Commission should consider whether extending TIMP requirements, and using other assessment tools such is ILI, would be a more appropriate response rather than limiting the options to only testing or replacing all pipeline.

A proper evaluation of deficiencies in PG&E's TIMP is also highly relevant to apportioning cost responsibility for the PSEP. PG&E has agreed that shareholders should be responsible for work made necessary because PG&E historically failed to perform work required by regulations.[18] PG&E has explicitly stated:

> We will also take responsibility for any other costs the Commission determines in the San Bruno OII, the Recordkeeping OII, and the Class Location OII . . . result from past alleged failures of PG&E to comply with regulations.[19]

Thus, PG&E acknowledges that the Commission's findings of violations in this and other enforcement dockets can and should affect the apportionment of PSEP costs between ratepayers and shareholders. Likewise, the Commission put PG&E on notice that while

[18] R.11-02-019, Exhibit 21 (Bottorff Rebuttal Testimony for PG&E), pp. 1-1 to 1-2.
[19] *Id.*, p. 1-2, lines 29-33.

cost responsibility issues will be addressed in Rulemaking 11-02-019, the Commission "may take note of the record evidence in this investigation" in the rulemaking.[20]

Under this principle, to the extent that PG&E should have previously hydrotested or in-line inspected pipeline presently scheduled for testing or replacement in the PSEP, then PG&E ratepayers should not shoulder the cost. The analysis in Section 5 of this testimony addresses this issue. Here, however, the point is that a comprehensive analysis of PG&E's past Integrity Management practices is not only necessary to promote safety, but also to ensure that the Commission has the factual record it needs to fairly apportion responsibility for PSEP costs.

There are two issues identified in the detailed investigations of Segment 180 that are relevant to system-wide integrity management. The first is the potential that PG&E did not appropriately identify all pipelines with manufacturing or construction defects. This issue is discussed in Section 4 below. The second is the likelihood that PG&E did not use the appropriate assessment method for significant portions of the pipeline that it did identify as having a manufacturing threat. This issue is discussed in Section 5 below.

4. THE □ð COMMISSION □ð SHOULD □ð INCORPORATE □ð THE □ð RESULTS □ð OF □ð THE VALIDATION □ŒJŁRT □ð TO □ð EVALUATE □ð PG&E'S □ð THREAT □ð IDENTIFICATION □ð

The Integrity Management deficiencies identified in the NTSB and CPSD Reports show that a key problem was PG&E's failure to properly identify manufacturing and construction threats.

In its 2004 Baseline Assessment Plan (" 2004 BAP") PG&E identified 457 miles of HCA pipeline as having potential seam or non-seam manufacturing threats, based on

[20] OIR, p. 11.

procedures detailed in its 2004 RMP-06 document. By the end of 2010, PG&E had disqualified almost 60 miles from consideration, primarily due to changing the classification of the pipeline to distribution status or reclassifying the segment location as non-HCA.[21] PG&E thus identified 400 miles of HCA pipeline with manufacturing threat in its 2009 BAP.

A number of record keeping and risk analysis deficiencies contributed to the fact that PG&E did not identify a manufacturing or construction threat on Segment 180 of Line 132 in its 2004 Baseline Assessment Plan ("BAP"). The CPSD Report explains that in the 2004 BAP PG&E did not list Segment 180 as having a manufacturing threat, even though adjoining Segment 181 was identified as having a manufacturing threat, simply because the installation date of Segment 180 (1956) was less than 50 years before 2004.

The NTSB Report explains that PG&E's GIS database system had mischaracterized Segment 180 as a "seamless" pipe due to errors in data input into the 1977 pipeline survey sheet, which used an accounting journal voucher as the source of data concerning pipeline characteristics.[22]

However, even if PG&E had correctly characterized Segment 180 as DSAW (double submerged arc weld) pipeline, PG&E did not consider DSAW pipe as an integrity threat, despite the conclusions of its own "Integrity Characteristics of Vintage Pipelines" report, which identifies DSAW pipe as having manufacturing defects.[23] Instead, PG&E used a risk algorithm with identified specific pipeline characteristics and

[21] PG&E Response to TURN DR 001-003, included as Attachment 2.
[22] NTSB Report, p. 27.
[23] CPSD Report, p. 41.

treated DSAW the same as if it were seamless pipe.[24] The CPSD report concludes that "PG&E's procedure should have considered the category of DSAW as one of the weld types potentially subject to manufacturing defects, and subject to Part 192.917(e)(3)."[25]

Given these identified problems, one particular issue that needs further investigation is the full scope of pipeline mileage (i.e., how much more than the 457 miles identified by PG&E) that should have been identified as having a manufacturing threat, if PG&E had used correct information about pipeline characteristics, had properly incorporated leak data and had given appropriate consideration to the threats associated with DSAW pipeline.[26] This question requires a close examination of the accuracy of PG&E's GIS database and records, the appropriateness of PG&E's risk algorithms in RMP-05, and the appropriateness of its integrity management procedures in RMP-06.

For example, if PG&E had properly identified DSAW pipeline as having a manufacturing threat, then PG&E should have increased its use of ILI to inspect DSAW pipeline. This issue has important implications for PSEP cost responsibility. In its PSEP, PG&E is proposing to pressure test 282.8 miles of DSAW pipe, which is the largest single weld type out of the 783 miles scheduled for pressure testing in the PSEP. If PG&E should have tested this pipeline as part of TIMP, then ratepayers should not be responsible for these costs.

PG&E will be reviewing and compiling all of its pipeline records as part of the "MAOP Validation" project in the PSEP. PG&E may find additional errors in the GIS database. Presumably, PG&E will use the corrected information as part of its ongoing

[24] NTSB Report, p. 62; RMP-05, Rev. 4, p. 6.
[25] CPSD, p. 41-42.
[26] This issue is also relevant to construction threats. TURN has simply not had time to address this issue.

integrity management plan. The Commission should order PG&E to file a comparison of the pipeline risk identification of all HCA pipelines after completion of the data validation to determine whether, and to what extent, PG&E's historical baseline assessment plans ("BAP") were inaccurate due to record errors and deficiencies.[27]

5. ANALYSIS OF AVAILABLE INFORMATION REGARDING SYSTEM-WIDE INTEGRITY MANAGEMENT DEFICIENCIES AND VIOLATIONS

Even without the comprehensive investigation of PG&E's Integrity Management practices urged in Section 3, the available evidence shows that Integrity Management violations have caused PG&E to fail to perform necessary and important assessments for a significant portion of its HCA pipeline. Moreover, much of that pipeline is now earmarked for testing or replacement in PG&E's PSEP.

In this section, TURN quantifies the potential magnitude of work that should have been performed by PG&E to properly assess manufacturing and construction defects, assuming conservatively that PG&E's identification of 457 miles of pipeline with manufacturing threat is correct.[28]

a. PG&E Used An Improper Assessment Method for Pipeline Manufacturing and Construction Threats

As noted above, PG&E identified 457 miles of HCA pipeline as having potential manufacturing threats in its 2004 Baseline Assessment Plan (" 2004 BAP"). This number

[27] It appears that PG&E's BAP will change dramatically due to the use of a different method for classifying high consequence areas (HCAs). This is a separate impact on BAP data.
[28] As noted in the previous section, the available evidence shows that more miles should have been indentified as having a manufacturing threat.

was reduced to 400 miles in the 2009 BAP due to changes in pipeline status or HCA location.

By the end of 2010, PG&E had assessed 357 miles of pipeline with manufacturing threats. PG&E assessed 322.95 miles of this pipeline using external corrosion direct assessment ("ECDA").[29]

PG&E should not have used ECDA for pipelines with manufacturing threats. ECDA is a primary assessment method only for external corrosion.[30] Direct assessment, including ECDA, is not the proper method to assess the risk of manufacturing or construction defects. PG&E's own procedures explain that ECDA is used to evaluate external corrosion and third party damage risks.[31] The primary assessment methods for manufacturing or construction threats are hydrostatic strength testing and in-line inspection. Non-destructive examination can also be used on exposed pipeline.

Indeed, PG&E's own plan was to use ILI for assessing manufacturing threats "whenever it is physically and economically feasible."[32] In its first Integrity Management Program plan, dated December 9, 2004 and created to comply with Part 192.907, PG&E had already decided to exclude pressure testing as an assessment method:

> Sec. 5.2. Background: The Company will choose the method or methods best suited to assess the identified threats to the HCA. These methods may include 1) In-line inspection tools … 2) Pressure testing 3) Direct assessment. …
>
> Sec. 5.4 Inline Inspection: It is the Company's **desire to inspect pipelines utilizing In-Line Inspection** (ILI), whenever it is physically and economically feasible. …

[29] PG&E Response to TURN DR 001-03. Included as Attachment 2.
[30] 49 CFR 192.923 and 192.925. The NTSB Report provides a summary of different assessment methods in Section 1.13.1. The NTSB Report further evaluates PG&E's assessment methods in Section 2.6.2.
[31] PG&E's RMP-06, Sec. 5.6; PG&E's RMP-09, Sec. 2.1.
[32] PG&E's RMP-06, Sec. 5.4.

Sec. 5.5. Pressure Testing: **The Company does not plan to use pressure testing** to assess the integrity of its pipelines. However, during the course of assessing data for ECDA or ILI, it may become apparent that pressure testing is the only feasible option. If so, the Company will perform a pressure test following the requirements found in Company's Gas Standards and Specifications A-37.

Sec. 5.6. Direct Assessment: Direct Assessment assesses integrity by the use of a structured process to integrate knowledge of the physical characteristics and operating history of a pipeline with results of inspection, examination and evaluation. **It can be used as a primary method only for external and internal corrosion, and stress corrosion cracking**. It may also be used as a supplement to other methods.[33]

Thus, at the **very outset** of integrity management PG&E had decided to rely primarily on ILI. PG&E acknowledged that ECDA was **not an appropriate primary assessment method** for threats other than corrosion. The language quoted above from Section 5 of the 2004 RMP-06 is repeated verbatim in every revision of RMP-06 in 2005-2010.[34]

PG&E offered no rationale in its IMP documents for deciding to eliminate hydrotesting as one of the three potential assessment methods. However, PG&E testified in the 2005 Gas Transmission and Storage rate case that hydrotesting will be limited so as to minimize customer impacts due to potential flow interruptions:

To verify pipeline integrity under these regulations [49 CFR 192, Part O], three assessment methods are allowed: Smart Pigging, Pressure Testing and Direct Assessment. PG&E has created the Pipeline Integrity Management Program to cover the work required by these new safety regulations. Smart pigging inspections that PG&E will perform to comply with the new rule have been determined to be capital expenditures due to significant pipeline modifications that must be implemented to facilitate pigging (such as valve and selected pipe replacement). Consequently, smart pigging has no impact on expected 2005 O&M

[33] PG&E RMP-06, "Integrity Management Program, Risk Management Procedure," Revision [0], dated 12/9/04 (emphasis added). This document is in the record in I.11-02-016 as document P2-371.

[34] These documents are marked as exhibits P2-372 to P2-376 in I.11-02-016.

> expenditures. **Pressure testing will be used on a limited basis since it requires the pipeline to be temporarily taken out of service to perform the test.** Direct Assessment and the associated physical excavations to inspect the pipeline are the primary Pipeline Integrity expenditures anticipated in 2005.[35]

In practice, however, PG&E failed even to use ILI properly to assess threats. Instead, PG&E relied predominantly on external corrosion direct assessment ("ECDA") to assess HCA pipelines. The NTSB Report notes that all of Line 132 was assessed exclusively with ECDA. The NTSB Report further notes that of the 1,021 miles of HCA pipeline, 813 miles were designated for assessment with ECDA and 208 miles with ILI. None were designated for assessment with hydrotesting.[36]

In actuality, during 2002-2010 PG&E assessed 649 miles of HCA pipeline using direct assessment, 171 miles using ILI and only 14 miles using hydrotesting.[37]

PG&E's use of ILI declined dramatically after 2008. PG&E used ILI to inspect an average of 123 miles per year in 2005-2008,[38] but then used ILI only for an average of 21 miles per year in 2009-2011. This dramatic decrease corresponds to a change in FERC accounting rules. Based on FERC guidance, starting in 2008 PG&E accounted for ILI costs as an expense, rather than a capital cost.

Of the 357 miles of pipeline with manufacturing threats assessed by the end of 2010, PG&E in-line inspected 34.35 miles, including 10.41 miles conducted using

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[35] A.04-03-021, PG&E Direct Testimony, dated March 19, 2004, p. 3-8, Kirkpatrick, PG&E (emphasis added).
[36] NTSB Report, p 112.
[37] PG&E Testimony in R.11-02-019, August 26, 2011, p. 2-17, Hogenson, PG&E.
[38] This number reflects the fact that PG&E ILI'ed much pipeline not in HCA locations. In total, PG&E ILI'ed approximately 826 miles of pipeline in 2000-2011.

transverse field inspection ("TFI") pigging.[39] PG&E thus assessed about 8.6% of its pipeline with identified manufacturing threat using ILI, and about 2.6% using TFI pigging, a method capable of evaluating longitudinal seam weld defects. .

PG&E now plans to test or replace 301 miles of the 400 miles of pipeline with manufacturing threat as part of its Phase I Pipeline Safety Enhancement Plan ("PSEP"). Of the 185 miles scheduled for replacement in Phase I of the PSEP, 62 miles had a manufacturing threat identified in the 2009 BAP, including 20 miles installed after 1955. Of the 783 miles identified for hydrotesting in Phase I, 239 miles had a manufacturing threat identified in the 2009 BAP, including 62 miles installed after 1955.[40]

PG&E should have performed a different assessment on the 400 miles of HCA pipeline in the 2009 BAP with identified manufacturing threats, including the 301 miles now included in the PSEP Phase I (239 for testing and 62 for replacement). PG&E shareholders should be responsible for the costs of testing or replacing these 301 miles of pipeline due to violations of integrity management.[41]

b. PG&E Failed to Hydrotest Lines With Operational Pressure Excursio

There is a separate and independent basis for finding Integrity Management violations with respect to the subset of pipelines with identified manufacturing threats

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[39] Traditional MFL pigging is capable of detecting anomalies along girth welds, while TFI pigging is capable of detecting seam weld anomalies.
[40] Due to database issues, TURN could only compare the contents of the PSEP with the 2009 BAP. As noted above, the 2009 BAP in total contained about 60 miles less of pipeline with identified manufacturing threat.
[41] Additionally and as a separate rationale, PG&E shareholders should cover the costs of testing and replacing the 82 miles installed after 1955 due to violation of industry standards, which required hydrotesting upon installation and the maintenance of certain test records.

where PG&E "spiked"[42] the pipeline pressure in order to set a five-year MOP. The CPSD and NTSB Reports explain in detail how PG&E spiked the pressure on Line 132 in 2003 and 2008 for this purpose.[43] PG&E believed that such spiking would allow it to argue that any future pressure increases would not exceed the "maximum operating pressure experienced during the five years preceding identification of the high consequence area." Pursuant to Part 192.917(e)(3) and ASME B31.8S, a pressure excursion would have triggered the need to perform a hydrotest to assess seam integrity.[44]

PG&E's intent in performing the pressure spiking was to avoid any possibility that a future pressure increase would trigger the need to consider an operating or manufacturing threat as unstable. The CPSD Report explains that PG&E should have considered the manufacturing threats on Segments 180 and 181 to be unstable due to any one of the following independent reasons: the occurrence of the pressure spikes after classification of the pipeline as an HCA pipeline, the information concerning Consolidated Western pipe welds contained in various records and reports, the fact that the spike test exceeded the pipeline MAOP, and the fact that PG&E did not conduct a cyclic fatigue analysis.

This analysis may apply to other pipelines. At a minimum, PG&E should be held accountable for its decision to spike other pipelines in order to avoid having to properly assess manufacturing or construction threats.

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[42] I use the term "spiked" to denote a pressure increase intended to preserve a five-year MAOP, not spiking as part of a hydrostatic pressure test. PG&E described these "planned pressure increases" in its letter to Paul Clanon dated February 2, 2011.
[43] CPSD Report, pp. 40, 44-49; NTSB Report, pp. 36-38, 112-113.
[44] NTSB Report, pp. 37, 112; CPSD Report, p. 40, 42-49.

PG&E spiked twelve lines (three of them more than once) in order to maintain the five-year MAOP at a constant value:

Table 1: Pipelines Spiked to Preserve MAOP[45]

Line No.	Dates of Pressure Spiking	Total Line Length	Length of Line Spiked	Length of Line with MT Identified in 2009 BAP
101	12/11/03	47.4	44.6	8.6
107	6/19/09	25.9	25.0	1.6
108	1/8/09	76.9	62.3	2.9
109	12/11/03, 11/14/08 4/12/10	57.4	52.7	12.9
132	12/11/03 12/9/08	53.8	46.6	28.4
138	10/30/08	34.6	35.2	2.2
0805-01	11/14/08	2.2	3.5	0.4
114	6/19/09	35.8	25.1	5.4
118A	1/8/10	81.2	84.7	12.2
142S	10/19/2004 8/13/09	11.6	9.0	8.0
1607-01	5/23/08	1.7	2.2	0.7
50A	7/20/10	43.3	24.4	2.7
Total		471.8	415.3	86.0

These spiked lines include approximately 415.3 miles of pipeline. Of this total, Approximately 86 miles were included in the 2009 BAP as having a manufacturing

[45] All data from PSEP database and PG&E Response to TURN R.11-02-019 DR 018-016. In some instances, the "length of line spiked" exceeds the "total line length," presumably due to the location of metering stations relative to the actual line, though TURN cannot fully explain this discrepancy.

threat. And of these 86 miles of spiked pipeline with manufacturing threats, 51.7 miles are included in the PSEP Phase I for testing (31.9 miles) or replacement (19.8 miles).[46]

The CPSD Report concludes that PG&E should have hydrotested Segment 181 due to the pressure spiking in December of 2003.[47] Similarly, PG&E should have hydrotested the 86 miles of spiked pipeline with identified manufacturing threats as part of its integrity management program. P&GE shareholders should thus be responsible for the cost of testing or replacing all of this pipeline, including the 51.7 miles included in Phase I of the PSEP.

6. THE □ð COMMISSION □ð SHOULD □ð INSURE □ð PROPER □ð INSPECTION □ð OF □ð FUT EXCAVATIONS □ð

The NTSB and CPSD Reports conclude that Segment 180 had significant manufacturing and construction defects that PG&E should have known about if it had followed good industry practice.[48] There is every reason to believe that such violations were not limited to Segment 180. However, the Commission lacks information about the extent to which similar violations occurred with other pipeline segments. The numerous excavations that PG&E will conduct as part of the PSEP testing and replacement work provide an important opportunity to collect key data concerning pipeline characteristics and potential defects. To ensure that such data is properly collected, TURN recommends that the Commission order the presence of independent qualified inspectors during excavations.

One of the obvious facts about natural gas pipelines is that for the most part they are located underground, and so cannot be visually or physically inspected. The purpose

[46] The remaining 34.3 miles are included in the PSEP Phase II.
[47] CPSD Report, p. 46-47.
[48] CPSD Report, p. 15.

of various assessment methods is to evaluate the pipeline through electronic measurements from within the pipe, through testing of the pipe by injecting an internal fluid, or through external assessment methods. However, whenever possible, actual visual and physical inspection of the pipeline provides crucial information.

The NTSB Report reaches conclusions regarding the failure of Segment 180 from detailed physical inspection of the pipeline itself.[49] The CPSD Report concludes that *if* P&GE had strength tested Segment 181, it would likely have discovered that Segment 180 was a DSAW pipe, presumably as part of the physical inspection performed when excavating Segment 181 to perform hydrotesting.[50]

Small sections of the pipeline are exposed during excavations necessary to install equipment and access the pipeline whenever hydrotesting or ILI is performed. Entire sections of the pipeline are exposed when PG&E replaces the pipeline. Such pipeline exposures provide a unique opportunity to inspect the pipeline and any exposed welds. Such examination will shed light on the question of whether the manufacturing and construction defects (including the installation of defective pipe and deficient girth welding) found on Segment 180 are present on other pipeline segments.

Such data will be highly relevant not just to determine the full extent of PG&E's violations, but also the cost responsibility apportionment of PSEP costs. To the extent inspectors find similar manufacturing or construction defects on pipeline PG&E is replacing as part of PSEP, and PG&E failed to properly account for such defects due to deficient records and/or improper integrity management practices, PG&E shareholders should be responsible for the costs.

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[49] NTSB Report, Sec. 1.8, p. 39-50.
[50] CPSD Report, p. 47-48.

In order to ensure collection of reliable relevant data, the Commission should require that PG&E hire, at shareholder expense, independent and qualified pipeline inspectors to be present at excavation sites to assess the condition of the existing pipeline. The presence of outside inspectors is vital not only to ensure unbiased inspection, but also because it appears that PG&E may not be properly capturing all relevant information during excavations.[51] The results of these inspections should be made public to parties in this proceeding, and should be incorporated in the Commission's deliberations concerning cost responsibility for PSEP work.

This completes my written testimony.

[51] The NTSB states the following concerning PG&E's ECDA procedure: "There is no requirement to update pipeline records with data collected from the excavation and examination portions of the ECDA process." NTSB Report, p. 109.

ATTACHMENT 1

Statement of Qualifications: Marcel Hawiger

My current position is Energy Attorney at TURN. I have held this position since August of 1998. I have represented TURN as the attorney of record in numerous proceedings since 1998, including various natural gas rulemakings, general rate cases, cost allocation proceedings, and a variety of other energy-related proceedings. I am a member of the Procurement Review Groups for all three IOUs. I have testified previously before this Commission.

Prior to my employment with TURN I was the Director of MidPeninsula Citizens for Fair Housing (1996-1998). I have also been employed by Evergreen Legal Services (1994-1996), the Massachusetts Department of Environmental Protection (1988-1990) and GHR Engineering, Inc. (1986-1988).

My education includes a Bachelor of Science degree in Geology from Yale University (1982), a Master of Science degree in Civil and Environmental Engineering from Cornell University (1988), and a law degree from New York University (1993).

ATTACHMENT 2

PGE Response to TURN DR 001-03