BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Pacific Gas and Electric Company with Respect to Facilities Records for its Natural Gas Transmission System Pipelines.	**I.11-02-016** **(Filed February 24, 2011)**

PREPARED DIRECT REBUTTAL TESTIMONY OF ROYCE DON DEAVER ON BEHALF OF THE UNITED ASSOCIATION OF PLUMBERS, PIPE FITTERS AND STEAMFITTERS LOCAL UNION NO. 342 AND INDIVIDUAL MEMBERS

(from R. 11-02-019)

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REBUTTAL TESTIMONY OF ROYCE DON DEAVER

I. Introduction

The Commission should start from the premise that significant work will be necessary to ensure the safety of PG&E's gas pipeline system. PG&E's system is old and full of dangerous conditions. The fundamental truth is that PG&E's system will need significant work if it is to be safe in the 21st century.

It is striking that there is broad agreement among the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), the City and County of San Francisco (CCSF), the City of San Bruno (San Bruno) and the U.A. Pipeline Locals on the vast majority of points discussed. In the following testimony, I address the few points on which we disagree. I also expand on some nuances of the issues on which we agree. My comments are focused on the methodologies that are necessary to determine the condition of each pipeline, and to do the work necessary to ensure safety.

While I do not agree with TURN's testimony that "new pipe is not necessarily better than old pipe," (Kuprewicz Testimony, p. 20), I do agree that a pipeline operator must ensure quality control throughout manufacturing, transportation and construction, and especially that unknown pipe qualities and poor girth welds may warrant replacement.

From an operational perspective, new pipe is affirmatively better than old pipe. New pipe is stronger. It benefits from modern manufacturing and welding methods, and it can be operated safely at higher pressures than can older pipe. Of course costs must be considered, but not at the expense of pipeline safety.

Replacing pipe that has characteristics known to be inherently unsafe will be more efficient than testing such pipe, experiencing leaks and ruptures, repairing, replacing, and re-testing. For example, electric welded pipe (EW pipe) should be replaced because the testing intervals required to ensure the safety of EW pipe are simply too close together to justify testing, and much of this pipe is likely to fail when tested to high pressures.

As TURN suggests, PG&E may be running its pipelines at lower MAOPs than one might expect because of the lack of high-pressure testing on these lines. PG&E's capacity problems may be caused, at least in part, by its failure to test pipes at high pressures. (See Kuprewicz Testimony, p. 32.)

New pipelines will help meet future needs. Replacing pipelines in strategic locations will be more cost-effective because the operator may not have to replace all of the older pipelines in order to reach the same capacity. Some older pipelines can be operated at lower pressures, or even taken out of service, if other old pipelines are replaced with higher-capacity pipelines. The entire testing and replacement process must be planned for future operability.

I agree with DRA's point that when one pipeline segment is hydrostatically tested, costs can be reduced and speed-of-completion increased by testing the adjacent and nearby pipeline segments. (Roberts Testimony, Exh. DRA-03, pp. 46-48.) Mobilizing and demobilizing crews and equipment before and after a hydrostatic test is a major element of cost and encumbrance. Work can proceed much more quickly and efficiently if the crews can finish work on one segment and turn right away to adjacent and nearby pipeline. For these reasons, I do not agree with CCSF's view that Class 2 pipelines should be categorically excluded from the initial phase of PG&E's hydrostatic testing and replacement work. (Gawronski Testimony, pp. 6-8 and 10.) I do agree, however, that Class 3, Class 4 and HCA locations should be given priority.

I also disagree with drawing any inference from CCSF's testimony that the start of PG&E's integrity management program in December 17, 2004, was the first time that PG&E was required to identify and assess its most risky pipelines. (See Gawronski Testimony, p. 11.) Since 1970, when the first federal pipeline safety rules were enacted, continuing-surveillance rules in 49 C.F.R. §192.613 and investigation-of-failures rules in 49 C.F.R. §192.167 have required that threats be investigated, corrective action taken, integrity of pipeline segments determined, hazards of failures evaluated, and remedial action taken to recondition or replace unsatisfactory pipelines.

Despite our few disagreements, on the vast majority of issues these five parties fully agree. The Commission should view this broad agreement as significant.

II. Performance-Based Standards Have Failed to Provide Pipeline Safety.

The Commission faces an historic re-evaluation of the rules necessary to ensure gas pipeline safety for California for the 21st century. The NTSB report, the IRPR, the Overland Consulting report and the opening testimony of the non-PG&E parties all make it plain that current federal pipeline safety rules are severely lacking in crucial respects.[1]

The good news is that California retains the power to set its own rules to ensure gas pipeline safety. California also has the power to enforce its new rules and to oversee the utilities' operations of their pipeline systems.

As discussed in my opening testimony,[2] in assessing how to ensure safety the Commission faces a critical threshold choice: does it follow the federal approach and continue along with industry-formulated, performance-based standards that lodge significant discretion and control in the pipeline owners and operators? Or does the Commission design specific safety requirements that prescribe what the utility is to do to ensure public safety? (See UA Locals' Opening Testimony, Exh. B, pp. 2-4, 31-35.)

The Commission will need to go beyond the very general performance-based rules set out in 49 C.F.R. Parts 191 and 192 and instead establish specific, prescriptive safety rules – clear, concrete rules that are not riddled with grandfathered and hoop-stress-based

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[1] See National Transportation Safety Board (NTSB) Report on San Bruno dated August 30, 2011, available at http://www.ntsb.gov/doclib/reports/2011/ PAR1101.pdf; Independent Review Panel Report, dated June 9, 2011, available at http://www.cpuc.ca.gov/PUC/ events/110609_sbpanel.htm; Overland Consulting, Focused Audit of PG&E Gas Transmission Pipeline Safety-Related Expenditures For the Period 1996 to 2010, dated Dec. 30, 2011, available at ftp://ftp.cpuc.ca.gov/SanBrunoReports/Focused%20Audit.pdf. See Kuprewicz Testimony, January 30, 2012; CCSF Testimony, January 30, 2012; DRA Testimony, Exh. DRA-03 and Exh. DRA-04, January 30, 2012; Wood Testimony, January 30, 2012.

[2] I explain how the federal pipeline safety rules are inadequate and laden with unwarranted exceptions. (UA Locals' Opening Testimony, Exh. B, p. 2.) It also appears that SB 705 (Leno, 2011) requires the Commission to create specific safety plans that would include specific requirements, not merely performance standards. See Cal. Pub. Util. Code §§ 955-969.

exceptions. The Commission should not follow the federal practice, embedded in the federal rules, of assuming that utility management will make the right choices and of relying on utilities to do the right things to ensure safety, without spelling out what those things entail.[3]

Many parties doubt the Commission's or PG&E's ability to actually fix the problems that have been discovered on PG&E's gas pipeline system.[4] While I share these concerns to some extent, I believe that their pessimism stems from the failure of performance-based standards to deliver the assurance of safety. To guard against the problems experienced in the past, the Commission should develop prescriptive rules to limit gas pipeline operator discretion in those areas that most affect safe construction, operation, maintenance and emergency responses.

Performance-based standards also frustrate appropriate cost allocation. I agree with CCSF (Gawronski Testimony, pp. 10-11) that incremental activities and their cost responsibilities should be based on prudent compliance with 49 C.F.R. Part 192 and industry standards. But this task may be insurmountable because 49 C.F.R. Part 192 includes vague performance-based standards in so many areas that it is difficult to determine what PG&E should have been doing to comply with the federal rules.

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[3] 40 C.F.R. Parts 191 and 192 contain over 300 areas where the pipeline operator is given the discretion to decide what constitutes compliance.

[4] See CCSF testimony (Teumin Testimony, Chap. 7, p. 57 ("PG&E's plan has a number of risks of satisfactory completion."); Teumin Testimony, p. 63 ("The chances of this project being completed effectively, on budget and on schedule are very low."); CSB Testimony (Wood Testimony, p.4 (noting, "to date there is no plan to gather detailed information and knowledge on the physical condition of specific line segments to be replaced and/or tested," and expressing concern with how PG&E will address its changing knowledge base as it faces future work)); TURN Testimony (Kuprewicz Testimony, p. 22 (worrying that "there is too much left to the discretion of the operator" in developing engineering condition assessments)); DRA Executive Summary, Exh. DRA-01, pp. 6-7 ("PG&E's PSEP Pipeline Plan is based on preliminary and incomplete evaluation of PG&E's records") and at p. 20 (noting that some threats are not correctly evaluated.))

In recommending that the Commission establish specific rules, I agree with San Bruno (Wood Testimony, p. 11) that the use of decision trees has a significant advantage over risk index models, because the bases for decisions are clear rather than being based on judgment-based decisions. These decision trees are the framework for PG&E to begin the development of clear prescriptive compliance procedures and programs. This step reduces the dependence on upper management performing risk analysis compliance decisions. Comprehensive, clearly-defined procedures allow delegation of more compliance activities to the grass roots level where compliance actions take place. This also requires grass root inspections and monitoring of grass roots compliance activities.

First and foremost, comprehensive prescriptive pipeline safety compliance procedures and programs are needed before any performance-based risk management process will work. (See ASME B31.8S.) Pipeline integrity should not involve a target to be aimed at; it should be a clear requirement.

Even if the Commission wanted to rely on performance-based regulations and rules, I agree with TURN's analysis (Kuprewicz Testimony, p. 13) that PG&E's admitted lack of historical and factual data detailing the operation of its gas pipeline system would prevent the Commission from establishing such rules. ASME B31.8S also indicates that performance-based compliance procedures are not appropriate where critical information is missing. The NTSB repeatedly recognized in its analysis that the metrics needed to determine the underlying causes of pipeline incidents and to implement comparative performance metrics are not available for performance-based regulation and risk analysis of safety benefits.[5] I am unaware of any comprehensive comparison of gas transmission operators' compliance practices, so no baseline of typical compliance practices exists.[6]

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[5] See National Transportation Safety Board (NTSB) Report on San Bruno dated August 30, 2011, pp. xi, 121-122 & 126-128), available at http://www.ntsb.gov/doclib/reports/2011/PAR1101.pdf.

[6] PG&E's gas pipeline system may be so unique that standards developed from the national experience of other utilities may be inapplicable to or ill-fit for PG&E's system.

Many parties express concern about how the lack of historical records and operational data precludes PG&E from designing an Implementation Plan with sufficient specificity to analyze whether it will work. CCSF correctly notes that PG&E "has not provided the Commission with an analysis in support of this program that complies with the CPUC order." (Scott Testimony, p. 24). DRA argues persuasively that PG&E should complete its MAOP validation before it can properly develop its Implementation Plan. (See DRA Executive Summary, Exh. DRA-01, pp. 6-7.) Given that PG&E is still in the process of finishing MAOP validation, we cannot definitely determine which pipelines need to be pressure tested and/or replaced.

The lack of basic data puts all parties – and the Commission – at a disadvantage in analyzing what should constitute priority safety work. The lack of data and records also results in PG&E's implementation plan "provid[ing] no analysis demonstrating that it will provide any greater or equivalent safety benefits." (Gawronski Testimony, p. 3.)

What we all must recognize is that theoretical analyses and best judgments will be necessary to craft a workable safety plan in this environment. A reliance on assumptions makes it all the more necessary for the Commission to establish a factual feed-back loop to benefit from actual experience as it is developed. (See U.A. Locals' Opening Testimony, Exh. B, p. 48.)[7] Given this situation, TURN's recommendations on records integrity are crucial. (Kuprewicz Testimony, pp. 4-5.) PG&E must institute quality control measures to ensure accurate data entry and data security, and record-keeping audits should be conducted on PG&E's record-keeping activities.

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[7] Because of the sense of urgency on pipeline safety, the Commission may be compelled to use best judgments on initial actions needed to ensure gas pipeline safety. This sense of urgency may result in overworking some issues and under-working others, but this may be difficult to avoid with the present inadequate level of pipeline safety metrics developed by the U.S. DOT and pipeline industry. Given the inadequacies inherent to this situation, the Commission should take pains to test the evidence and assumptions wherever possible, to create as robust a record as possible.

I share the concerns of CCSF (Teumin Testimony, pp. 50-55) about PG&E's ability to properly and efficiently comply with their implementation plan and its ability to develop and implement meaningful pipeline safety programs. Required pipeline safety work must be assigned to a technically- capable staff of engineering and technical personnel with long-term involvement in development and execution of programs. Without comprehensive, but clearly stated prescriptive rules, PG&E and other pipeline operators will be performing safety enhancement activities in an uncertain compliance environment. Clear-cut and specific rules will make the jobs of ground level personnel easier because the requirements will be unmistakable. Prescriptive rules will make it easier to achieve "effective project management and strong project oversight" which the City of San Bruno notes "are fundamental to effective implementation . . . ." (Wood Testimony, p. 8.)

The problems raised by the lack of historical records and basic information about the design and contents of the pipe are compounded by the approach PG&E takes in developing assumptions about its gas pipeline system's performance. TURN's analysis of PG&E's calculations and assumptions to validate the MAOP of its pipelines highlights a critical concern that we share (See Kuprewicz Testimony, pp. 13, 64, 67-68.) Knowing information about the design of the pipe and its pressure testing history is essential to the ability to set the correct MAOP. I agree with TURN that without traceable, verifiable, and complete records to determine a valid MAOP, PG&E cannot rely on "conservative" assumptions, but instead must conduct a hydrotest, including a spike test, for every pipe segment." (See *id.*, p. 66.)

I agree with TURN (*see, e.g.*, Kuprewicz Testimony, pp. 4-5, discussing records integrity) that in creating assumptions, whether it involves calculating MAOP, determining the service life of the pipelines, manufacturing or operational wear, or any other operational issue, **the Commission should require that worst case and only worst case assumptions be used.** Industry best practices also require that if historical data is lacking, the pipeline operator must assume that its pipelines are comprised of the weakest possibilities, not the strongest.

Allowing only worst case assumption calculations is consistent with current federal rules in 49 C.F.R. Part 192, Subpart C. The assumptions as to type of pipe in the ground should be the most conservative. For instance, the Commission should prohibit the utilities from assuming that seamless and other pipe with a design seam factor of 1.0 has been used; instead, without definitive information, the utilities must assume the use of pipe with a lower longitudinal seam design factor. Similarly, the Commission should not allow assumptions that pipe thicknesses are anything more than the thinnest pipe made in the sizes available at the time of installation. Otherwise, the assumption is a speculative, best-case analysis of the pipe's ability to sustain higher pressures.

The lack of data and records also causes problems for the Commission in determining cost allocation. CCSF notes that "PG&E's proposal clouds the issue of what is truly incremental." (Gawronski Testimony, p. 3.) I agree that the incremental cost issue is important to determining who should pay for the work outlined in the Implementation Plan. However, in my opening testimony, I recommended that the Commission create a continuous feedback look to assist it in its monumental cost allocation evaluation task. (U.A. Locals' Opening Testimony, pp. 48-50.) Because of the vague federal safety compliance standards and the lack of historical records, the Commission's incremental cost analysis will most likely need to be made using general utility ratemaking principles. (See U.A. Locals' Opening Testimony, Exh. B, pp. 34-50.)

III. It Is Critically Important to Choose the Appropriate Testing Methodology to Ensure Pipeline Safety.

1. PG&E Must Use High Pressure Testing for Results to Be Reliable.

I agree with TURN that PG&E should use very high pressure when conducting hydrostatic testing.[8] (Kuprewicz Testimony, p. 29.) While TURN is correct that high

[8] Many intervenors, including myself, use the term "hydrotesting." As a point of clarification, I note that the proper term is "hydrostatic pressure testing" because this emphasizes the "static" part of the test, which is critical for leak detection. This indicates that the pressure test will be held at a constant level of pressure for a particular length of time, which is the only way to ensure an accurate test result.

pressures should be used, pressure testing recommendations should not be based on undefined "prudent" considerations. (*Id.*, p. 20 & 33.) TURN suggests that pipes be tested to 90% of SMYS. (*Id.* p. 31.) While I do not disagree with this recommendation, more specific requirements, including test-pressure-to-MAOP ratios, are also needed to ensure safety.

My testimony on pressure testing and seam factors for early electric weld pipe was included as Exhibit B to the UA Locals' testimony. There I explained that pressure testing for pre-1980 electric resistance welded and electric flash welded pipe (EW pipe) should take into account a "longitudinal joint factor" of approximately 0.63 to account for the particular weakness of EW pipe. (See UA Locals' Opening Testimony, Exhibit B, p. 17.) When this recommended longitudinal joint factor of 0.63 is applied, the pipe should be tested to 1.6 x MAOP for class 1 locations, 1.8 x MAOP for class 2 locations, 2.1 x MAOP for class 3 locations, and 3.0 x MAOP for class 4 locations. (*See id.*, p. 19.)

For seamless and double submerged arc welded pipe manufactured to a standard that does not match API 5L quality level 2, the test pressure should range from 1.25 x MAOP for class 1 locations, to 1.8 x MAOP for Class 4 locations. (*Id.*, p. 20.) For seamless and double submerged arc welded pipe (DSAW) manufactured to a standard that matches API 5L quality level 2, the pipe should be tested to a minimum test pressure of 1.25 x MAOP for class 1 and 2 locations, and 1.5 x MAOP for class 3 and 4 locations. (*Id.*) My opening testimony contains a detailed explanation of these calculations.

2. Temporary Pressure Reductions Must Be At Least 20% Reductions.

I agree with CCSF that PG&E's proposed pressure reductions are "unnecessarily limited to modest pressure reductions and that greater pressure reductions could be achieved if safety concerns warrant." (See Scott Testimony, pp. 24-25.) A pressure reduction of only *20 psi* in a gas transmission line is unlikely to achieve any significant safety margin. The safety margin used by the U.S. DOT is routinely a *20 percent* or greater reduction in maximum operating pressure in a pipeline until the safety issues are defined and corrected.

Additionally, industry pipeline repair manuals recommend that if the possible presence of severe anomalies cannot be ruled out, the operator should lower the pressure level to 80 percent of the highest level when the last inline inspection survey was performed. (*See, e.g.*, J.F. Kiefner, W.A. Bruce & D.R. Stephens, Pipeline Repair Manual, Pipeline Research Council International, Inc., Catalog No. L51716e, rev. Dec. 1999, available at http://www.scribd.com/doc/51083861/Pipeline-Repair-Manual, pp. 4-5.) The *Pipeline Repair Manual* by John Kiefner recommends that this lower pressure level should be maintained until all anomalies have been examined and repaired, or the pipeline operator can be confident that the remaining unexamined anomalies present no immediate potential threat. (*See id.*)

The *Pipeline Repair Manual* also explains that soil movement, settlement, and/or pipeline support conditions may impose unknown or unpredictable stresses on a defect. In such cases, it may be prudent to consider pressure reductions larger than 20 percent. (*Id.*)

Since extensive excavations of operating pressures will be required during various safety enhancement activities, PG&E's pipeline systems will need to accommodate numerous pressure reductions of at least 20 percent without serious disruptions in gas service. Facility additions and modifications that are needed to minimize gas service disruption should be part of PG&E's Implementation Plan.

I further agree with CCSF that "[t]he proposed pressure reductions of up to 20 psig ... appear[] to be modest compared to the initial pressure reductions of 20 percent that the Commission required for the San Bruno line." (See Scott Testimony, p. 43.) A reduction of 20 percent should be considered as a temporary safety measure, until longer term remedial actions are taken such as pressure testing, repairs, and/or replacement. A reduction of 20 psig is simply inadequate to provide any assurance whatsoever, even on an interim basis.

CCSF is correct that "[t]he CPUC requirement for a 20 percent pressure reduction for the San Bruno pipe was not constrained by whether non-core load could be met, nor should it have been." (See CCSF Testimony, p. 44.) PG&E should have been and should now be revising and adding facilities to meet gas demand requirements under any temporary pressure reductions of at least 20 percent. Given the problems uncovered so far, PG&E may well discover additional safety-related conditions that could affect gas delivery. PG&E needs to identify those possible conditions immediately and develop either interim or long-term improvements whenever it is warranted. The Commission should require PG&E to supplement its Implementation Plan to include these planning measures so PG&E can avoid any gas curtailments while still acting to implement safety upgrades.

3. Corrosion Evaluation Requires In-Line Inspection Tools and Hydrostatic Testing.

I agree with TURN that inline inspection is generally a better corrosion evaluation tool than hydrostatic pressure testing. (See Kuprewicz Testimony, p. 26.) However, for pipe with seam welds subject to selective seam corrosion, pressure testing is a better evaluation tool because corrosion-type inline surveys are not sensitive to linear corrosion.

Both hydrostatic pressure testing and inline inspections are necessary for all manufacturing-related and all corrosion-related threats. This is why I suggested that separate decision trees should be developed for mechanical damage, external corrosion, and internal corrosion. (See UA Locals' Testimony, Exhibit E.) These three types of threats have little in common. Including all in a single decision tree creates confusion. Each of these three categories needs a separate decision tree to ensure that all relevant factors are considered in the decision making process.

TURN also suggests that ILI should be used for corrosion testing for over 400 miles of pipeline instead of hydrotesting. (See Kuprewicz Testimony, p. 26.) However, this is not realistic because 80% of PG&E's pipelines are not piggable. PG&E should initially prioritize hydrostatic testing.

IV. Assessment and Replacement of Pipe

1. Girth welds should be visually inspected and x-rayed.

I agree with TURN that hydrostatic testing is not the most appropriate evaluation tool for girth welds. (See Kuprewicz Testimony, p. 22.) I also agree with DRA that fabrication and construction defects are primarily susceptible to axial threat stresses. (See DRA

Testimony, p. 21.) However, inline inspection methods are very limited in their capability to detect defective girth welds. I believe that hydrostatic pressure testing is more likely to be effective for construction threats than inline inspection. To properly evaluate construction threats, PG&E should also excavate pipelines and visually inspect and radiograph (x-ray) girth welds in accordance with 49 C.F.R. § 192.715. During the same excavation, PG&E could perform physical assessment of coating damage and check for corrosion.

In pipeline segments with girth weld integrity concerns, a statistical model will need to be developed to determine the number of excavations and girth weld repairs that will be made before line replacement is warranted. When performed with coating and corrosion inspection and repairs, this combined activity constitutes a common practice in pipelines referred to as pipeline reconditioning and rehabilitation.

2. Replacement of Pipelines May Be More Cost Effective in Certain Circumstances than Testing, Repair, and Re-Testing.

Today's pipeline modernization planning should include both present and future needs when long-term cost efficiencies are possible. Where pipe replacements are deemed appropriate, larger pipelines with capacity for future needs will be the most reasonable replacements from a cost-efficiency perspective.

I agree with TURN that "if the pipe qualities are unknown or poor girth welds in unstable soils exist, then replacement may be warranted, but the decision tree does not clearly identify or summarize" how such pipe would be selected for replacement. (See Kuprewicz Testimony, p. 20.) However, I would disagree with the characterization of replacing pipe as "extreme." (*See id.*) As discussed above, EW pipe must be tested to high pressures to ensure safety. EW pipe, particularly in Class 3 and 4 locations and all high consequence areas, should be replaced because it is likely that replacement will be more cost-effective than testing, repair, and re-testing. Moreover, extensive testing, repair and re-testing may not be sufficient to ensure safety.

I agree with DRA that some threats are not correctly evaluated, but I disagree that the number of pipeline segments to be replaced are "excessive." (See Rondinone Testimony, Exh. DRA-04, p. 20.) When future gas transportation needs are considered, and test pressure limits are re-determined for older pipelines, MAOPs may be lowered, resulting in lower gas transportation capacity. Further, I believe strongly that replacement projects should not be halted while PG&E revises its decision trees.

TURN explains that because pipelines have not been tested to high pressures, the MAOP for certain pipe segments may be lower than one might expect. (Kuprewicz Testimony, p. 32.) This, in turn, lowers PG&E's transportation capacity, and requires them to make additional requests for capital to expand capacity. (*See id.*) TURN is right to be concerned that PG&E has requested excessive capital for capacity expansions in recent years; however, this should not serve as a deterrent to expanding capacity during replacement. PG&E's current plan for replacing inadequate pipelines may and should include some capacity increases and line re-routes. These should be identified clearly. However, it will not be efficient to simply replace all pipelines needing replacement with new lines that contain precisely the same diameter and same maximum allowable operating pressure. Such a requirement would be short-sighted and may increase overall costs if future requirements are not considered.

3. Distinctions Based on 30% of SMYS Should Be Eliminated.

I agree with DRA and CCSF that PG&E inappropriately prioritizes pipelines operating at greater than 30% of SMYS when it was supposed to be focused on Class 3 and 4 locations and HCAs. (See Rondinone Testimony, Exh. DRA-04, p. 8; Scott Testimony, p. 8.) However, I would go further than DRA and CCSF, and eliminate the 30% of SMYS distinction entirely. (See UA Locals Testimony, Exhibit B, pp. 31-32.) Data reported to the U.S. DOT concerning leak and rupture incidents show there is not a strong correlation between gas transmission incidents and operation above 30% of SMYS. About half of the gas transmission incidents occurred at a hoop stress of less than 20% of SMYS.[9]

[9] PG&E's threat decision trees exempt gas transmission lines operating at less than 20% of SMYS. This exemption should be eliminated and all transmission lines should be subject to the decision tree analyses. (See UA Locals' Testimony, Exhibit E, p. 2.)

Although other intervenors may argue that this includes data on leakages in addition to data on ruptures, the data on ruptures alone also supports this conclusion. The UA Pipeline Locals' Opening Testimony, Exhibit C, analyzes exemptions for low hoop stress and low pressure gas transmission lines, and includes data on both ruptures and leaks. Data is available from an American Gas Association report on 1,635 gas transmission in service incidents.[10] Over 50% of the incidents reported as ruptures occurred at a hoop stress of less than 12,000 psi, which is only 23% of SMYS for X-52 pipe. Over 71% of the incidents reported as leaks occurred at a hoop stress of less than 12,000 psi, which is only 23% of SMYS for X-52 pipe. Finally, 18% of the ruptures occurred at a hoop stress of 1,000 psi to 3,000 psi, which is only 2% to 6% of SMYS for X-52 pipe. Exemptions from testing based on hoop stress should be eliminated.

4. New Data Must Be Incorporated During Testing and Replacement.

I agree with the City of San Bruno about PG&E's lack of information on how it plans to handle its changing knowledge regarding its own pipelines. (See Wood Testimony, pp. 3-4.) Mr. Wood identifies concerns about how PG&E will deal with its changing knowledge base as projects are completed, and how this changing knowledge will affect future work.

San Bruno shows that PG&E has no plan to gather detailed information and knowledge on the physical condition of specific line segments to be replaced and/or tested. (Wood Testimony, pp. 3-4.) Once a pipeline is replaced, it is unclear whether it will it be abandoned in place, or if there will be efforts to perform an "autopsy" on the actual condition of the pipe taken out of service.

Information on the actual condition of line segments would help predict the condition of other similar lines. It would be helpful in identifying what corrective actions should be taken. Information on the actual corrosion, mechanical damage, and other discovered threats would also be helpful in determining where PG&E failed to follow prudent pipeline safety practices, and when conditions were beyond PG&E's control for cost allocation purposes.

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[10] Gideon, Kiefner and Smith of Battelle. *Unnumbered AGA Report* on gas transmission and gathering pipeline incidents during 1970-1973 (October 2, 1975).

V. Changes to the Decision Tree.

1. Manufacturing.

I agree with DRA that low frequency electric resistance welded, electric flash welded, and lap-welded pipe experience premature failures. (Rondinone Testimony, Exh. DRA-04, p. 6.) Exhibit D to the UA Locals' testimony analyzes problems that occur with early electric weld pipe and details numerous premature failures of this type of pipe.

I agree with the City of San Bruno's suggestion that the Manufacturing Threats decision tree should not exclude pipe made in 1970 and later. (Wood Testimony, p. 4.) I agree with Mr. Wood's observation that ERW pipe was used as late as 1978. (*Id.*) Thus, I propose asking whether pipe was made before 1980 to determine whether it should be tested or replaced, because low-frequency ERW pipe was made as late as 1978. (See Exhibit E to UA Locals Testimony, p. 3.)

a. Fatigue Analysis.

I agree with City of San Bruno that certain decision trees exclude key criteria. For example, Mr. Wood notes that one decision tree box requires PG&E to "reduce pressure <u>and/or</u> remaining life fatigue analysis" which is ambiguous. (Wood Testimony, p. 4.) Rather than using an "and/or" criteria, PG&E should reduce pressure as an interim measure and then conduct a proper fatigue analysis. Proper fatigue analysis should include external load assessment (thermal effects, external loads, non-seismic ground movement and seismic ground movement), all sources of stress (not just hoop stress), and should be based on fatigue growth rates for below-ground piping, not above-ground piping. (See Exhibit E to UA Locals Testimony, p. 3.)

b. DSAW Pipe.

I agree with TURN that PG&E should include DSAW pipe in the manufacturing threat evaluation. (Kuprewicz Testimony, p. 19.) I also agree with TURN that hoop stress is an important consideration in threat evaluation, but it is not the only stress that should be used in threat evaluations. DSAW pipe should be subject to a remaining life analysis in the manufacturing threat decision tree. The remaining life analysis should include an external load assessment, all sources of stress (not just internal pressure effects), and should be based on fatigue growth rates for below-ground piping, not above-ground piping.

2. Construction/Fabrication.

I agree with City of San Bruno that 1960 is not an appropriate cutoff date for poor construction and fabrication practices. (See Wood Testimony, p. 4.) My opening testimony recommends asking whether such pipe was installed before 1975. (See UA Locals' Opening Testimony, Exhibit E, p. 4.) This does not mean that later pipelines are immune from such problems.

DRA is right that Subpart J testing was incorrectly used to evaluate potential pipe joint fabrication threats, and should not be used as a decision criterion for fabrication and construction threats. (See Rondinone Testimony, Exh. DRA-04, p. 1.) However, I disagree that strength tests that do not meet current criteria should be permitted in phase 1. (See Rondinone Testimony, Exh. DRA-04, p. 11.) An inaccurate, insufficient, low-pressure hydrostatic test will do no more to ensure safety than not testing at all. Such records should not be relied on in Phase 1 or Phase 2.

I agree with DRA that lines with joints, bends, and weld types identified in the fabrication and construction threat decision tree should be replaced. (Rondinone Testimony, Exh. DRA-04, pp. 6-7.) Their removal is needed for pigging and integrity purposes. I disagree that miter bends up to 8 degrees are not weaker than the base metal, because the calculated stresses are substantially higher than in the pipe and exceed the stress limits in ASME B31.8. (*See id.*) Miter bends can be subject to fatigue failure due to the higher localized stresses in the miter joint. Excessive miter bends can also impede the passage of inline inspection tools.

Welding prior to World War II is more likely to be defective, as DRA notes (Rondinone Testimony, Exh. DRA-04, p. 7), because welding advances developed during the war increased pipeline construction and manufacturing quality substantially. However, I strongly disagree with DRA's suggestion to rely extensively on fatigue analysis for pipelines dating back to 1955. (*See id.*, p. 11.) Even after 1970, when 49 C.F.R. Part 192 was first issued, pipeline companies seldom maintained records of pressure cycles and seldom, if ever, performed fatigue analysis. External load analysis and documented reassessments of external loads were seldom performed.

All sources of stress should be considered in conducting fatigue analysis, as I demonstrate in my opening testimony. (See UA Locals' Opening Testimony, Exh. B, p. 32 and Exh. E, p. 3.) Fatigue analysis cannot be accurately performed unless all sources of stress and the corrosive effects on fatigue crack growth are known. If all sources of stress are not considered, the projected life of a particular pipeline will be calculated erroneously. For all of these reasons, I do not recommend any reliance on historical fatigue analysis.

I agree with DRA that an assessment should be performed that includes the potential for soil movement (seismic and otherwise). (Rondinone Testimony, Exh. DRA-04, p. 12.) All sources of external loads should be considered, in addition to internal pressure. Since 1955, ASME B31.1.8 has included requirements for stress analysis of loads other than internal pressure, and these requirements should be consistently performed.

3. Corrosion and Mechanical Damage

The City of San Bruno properly questions whether in-line inspection, hydrotesting, close interval surveys (CIS), and Direct Current Voltage Gradient testing (DCVG) are equivalent. (Wood Testimony, p. 4.) In fact, there is no basis for considering these techniques equivalent. CIS and DCVG are indirect assessments and do not necessarily include excavation and physical examination of the pipe. Without extensive excavations and inspections, CIS and DCVG are not as reliable as hydrostatic testing or in-line inspections.

I agree with CCSF that "given the pressing safety issues, PG&E could maximize its chances for success by implementing a much simpler, streamlined plan." (Teumin Testimony, p. 57.) Given pressing safety issues, I agree that PG&E's decision trees should be broken down into more specific threat categories so that analyses and decisions are easier to follow. My opening testimony proposed to break down the single corrosion and mechanical damage decision tree into three separate trees. Separate decision trees are proposed for mechanical damage, external corrosion, and internal corrosion, because the underlying causes of each are not closely related. (See UA Locals' Testimony, Exhibit E, pp. 5-10.)

VI. Efficiency and Prudence Will Sometimes Favor Testing Segments in Class 1 and 2 Areas when Class 3 or 4 or HCA Segments Are Tested.

All the parties agree that a great deal of work will be needed to make PG&E's gas pipelines safe. Obviously, this work should be done as efficiently as possible.

CCSF asserts that Class 1 and Class 2 locations should be excluded from the Commission's first-phase of hydrostatic testing and replacement, unless those locations are in high-consequence areas. (Gawronski Testimony, pp. 8-10.) Although I agree that Class 3 and 4 locations and HCAs should be prioritized, I disagree with CCSF's hard-and-fast-rule proposal for two reasons.

First, efficiency counsels against a hard-and-fast rule. Gas pipelines run through varied class locations. Gas-pipeline testing and replacement requires substantial investment in mobilization and demobilization (moving crews and equipment into and out of work areas) and excavating test sites. This work is expensive and time-consuming. (See, *e.g.*, Delfino Testimony, Exh. DRA-05.)

Non-HCA Class 2 locations often adjoin Class 3 and 4 locations. When PG&E's and its contractors' crews have completed testing or replacement at a Class 3 or 4 site, they should not be prohibited from testing or replacing an adjoining or nearby pipe segment that needs such work just because it lies across a line of class demarcation. Hydrostatic testing and pipe replacement decisions should be based on logistics and efficiency, not on hard-and-fast class-location strictures. I therefore agree with DRA (see Roberts Testimony, Exh. DRA-03, pp. 46-48) on this issue. I agree with DRA's recommendation to focus on HCAs, Class 3 and 4 locations, with nearby Class 2 locations also included (see Randinone Testimony, Exh. DRA-04, p. 10), but I believe more flexibility may be needed to deal with particular pipe segments than as proposed by DRA's rules.

CCSF's suggested rule would slow the pace of work and make it unnecessarily expensive. The Commission should not adopt it.

Second, hard-and-fast class-priority rules would not be based in reliable fact. PG&E acknowledged in June 2011 that its class-location designations are inaccurate. Moreover, California is under continual development, so yesterday's Class 2 location is today's Class 3 or 4 location.

In carrying out the Commission's orders for hydrostatic testing and pipeline replacement, PG&E will need to adapt to the realities it encounters along the way. A hard-and-fast prohibition on testing and replacement in areas classified as Class 2 would impair that ability.

VII. Potential Impact Radius Calculations Contained In Federal Rules Cannot Be Relied Upon.

I agree with the City of San Bruno that there is a need to improve pipeline emergency response capability and planning. (Wood Testimony, pp. 1 & 4.) However, many parties incorrectly rely on current federal standards in 49 C.F.R. Part 192 for calculating the potential impact radius (PIR) for fires occurring at gas pipeline rupture points. The recommended PIR equation appeared in Gas Research Institute Report No. 00/0189, *A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*.[11] But the federal regulations underestimate the actual potential impact radius, which may lead to dangerous emergency response conditions for local responders and inadequate evaluation of the risk to public safety.

Federal regulations include the assumption that there exists only a 1% mortality rate at the boundary of the PIR distance from the pipeline rupture. That assumption significantly underestimates the actual impact radius at San Bruno (over 900 feet for buildings and greater distances for people who could have been exposed). Similar PIR rupture areas would likely occur in the future should PG&E's gas pipelines remain in their current condition. As I

[11] See Mark J. Stephens, *A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*, Prepared For the Gas Research Institute, Contract No. 8174 (October 2000), available at http://www.cycla.com/opsiswc/docs/s8/p0054/IMPGas_00-0189HCAsize.pdf.

explained in my opening testimony, the current PIR calculation in 49 C.F.R. Part 192 is based on the following conditions:

a. Instant ignition, rather than a delay and build-up of gas.

b. A radiant heat level of 5,000 BTU per $ft.^2$ per hour.

(U.A. Locals' Opening Testimony, Exh. B, pp. 20-23.)

The current PIR calculation assumes that people exposed to the rupture will only be so exposed for 30 seconds, and relies on data showing that the mortality rate is 1% for industrial workers with only 30 seconds of exposure. However, if the time of exposure increases to 60 seconds, the mortality rate jumps to 50% and if the exposure time increases to 120 seconds, the mortality rate jumps to 100%. (See UA Locals' Testimony, Exhibit B, pp. 20-23.)

TURN's testimony regarding PIR calculations (Kuprewicz Testimony, pp. 48-49) also addresses the too-small calculation of the area that will actually be affected by future gas pipeline ruptures. Unfortunately, TURN's Figure 8 (Kuprewicz Testimony, p. 47) did not incorporate the possibility of flying sparks or embers igniting buildings close by. Figure 8 should include the effects of fires occurring within the current PIR radius that would be sources of ignition for buildings located outside the PIR.

In general, I agree with TURN's conclusions (Kuprewicz Testimony, p. 50) that the safety of first responders who are close to a pipeline rupture fire must be of concern to the Commission as it sets future rules. I also agree with TURN (Kuprewicz Testimony, p. 36) that a more detailed evaluation of pipeline rupture dynamics, including an isolation blow-down time (pipeline pressure reduction time) and pipeline diameter, should be used in the decision tree process. Moreover, I agree with TURN that the current PIR calculation should not be the primary criterion for selecting segments for valve automation or prioritizing the valve automation program. (See Kuprewicz Testimony, p. 34.)

Because local responders and other people caught near the pipeline rupture will likely experience much longer fire exposure times than 30 seconds, the present PIR grossly underestimates what constitutes a safe distance from a pipeline rupture fire. My opening testimony details why the potential impact distance needs to be based on a delayed ignition; demonstrates that the potential impact distance should be based on exposure conditions other than those occurring in an industrial setting with industrial workers, many of whom are trained and all of whom have access to protective gear; and explains why potential exposure times longer than 30 seconds need to be incorporated into the PIR calculation. (See U.A. Locals' Testimony, Exh. B, pp. 20-23.)

As I conclude in my opening testimony, the correct PIR equation, incorporating real-world conditions, is five times the present PIR equation in 49 C.F.R. Part 192.

VIII. Valve Automation

With respect to shut-off valve issues, the Commission must first determine the goals it wants to achieve. I agree with the City of San Bruno that PG&E's capability to "quickly and reliably terminate the flow of gas through a ruptured line" should be the critical focus. (Wood Testimony, pp. 5-6.) I also agree with the City of San Bruno (Wood Testimony, pp. 6-7) that *where* to install automated valves is important, but I believe that knowing *when* to close the valves is equally important. At base, PG&E's valve automation proposal is too preliminary and needs much more analysis before the Commission can properly decide what components it should approve.

I draw the Commission's attention to CCSF's recommendation that PG&E should perform an analysis *at least* consistent with 49 C.F.R. 192.935(c) in developing its proposal for valve automation. (Scott Testimony, pp. 26-27.) Mr. Scott correctly explains that PG&E's June 14, 2006 memo on valve automation "relied solely on one-sided industry studies and did not address any of the seven factors specified in 49 C.F.R. 192.935(c)." (*Id.* at p. 28.)

TURN correctly observes that PG&E's contention that remote control valves can be later converted to automatic and thus automatically *or* remotely operated, is troubling. (Kuprewicz Testimony, pp. 3-4 & 59.) Remotely operated valves usually require manual action to "push a button" to operate the valve. As I explained in my opening testimony, a remotely-operated isolation valve is of little use unless the occurrence of a larger leak or rupture is known to the pipeline operator. (U.A. Locals' Opening Testimony, Exh. B, p. 27.) Furthermore, knowledge of the leak or rupture *location* is also necessary to know which valves to close to minimize critical service disruptions.

As I detail in my opening testimony, the pipeline SCADA control-center personnel must know when and where a large leak or rupture has occurred. This requires *continuous* monitoring of pressure and flow rate to detect an abrupt change in flow and pressure. Pipeline SCADA systems do not normally perform continuous monitoring of pressure and flow rate. A polling or scanning technique is used to gather information on pipeline operating conditions and equipment status. With a polling or scanning SCADA technique, a sudden change in pressure or flow conditions can be missed between scan times. (See U.A. Locals' Opening Testimony, Exh. B, p. 27.)

I also agree with TURN (Kuprewicz Testimony, p. 4) that pipeline rupture analysis or modeling should be used both in the decision tree process and the prioritization process. While I also agree with TURN that valve automation priorities in Phase 1 should focus on Class 3 and 4 locations and larger diameter pipelines, I disagree that a maximum valve spacing be set at this time. (*See id.*) TURN is silent as to Phase 2 valve automation work. I believe that Phase 2 priorities should continue to include valve automation work.

R.D. Deaver