PREPARED TESTIMONY OF RICHARD KUPREWICZ EVALUATING PG&E'S PIPELINE SAFETY ENHANCEMENT PLAN

CALIFORNIA PUBLIC UTILITIES COMMISSION

PIPELINE SAFETY RULEMAKING

R. 11-02-019

Submitted on behalf of

THE UTILITY REFORM NETWORK (TURN)

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January 31, 2012

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RICHARD KUPREWICZ DIRECT TESTIMONY

This testimony is submitted by Richard Kuprewicz on behalf of The Utility Reform Network ("TURN") in California Public Utilities Commission Proceeding OIR 11-02-019. Mr. Kuprewicz has over 25 years of operational experience in the energy and pipeline industry, with special focus on appropriate pipeline design and operation in highly sensitive areas. He has been a consultant since 1999, focusing on pipeline safety and regulatory compliance. He serves as a public representative on the Technical Hazardous Liquid Pipeline Safety Standards Committee, and he served as a member of the public on the Executive Steering Committee that assisted PHMSA in developing a report concerning distribution integrity management program (DIMP). His qualifications are included in Attachment 1.

The testimony provides an evaluation of the "Pipeline Safety Enhancement Plan" ("PSEP," also referenced as the Implementation Plan or "IP") submitted by the Pacific Gas & Electric Company ("PG&E") on August 26, 2011. It provides analyses and recommendations concerning changes to PG&E's decision tree process charts, the different elements of the plan, as well as some comments on PG&E's past performance as a pipeline operator.

1. Introduction and Summary of Recommendations

1.1. Summary of PG&E's Implementation Plan Costs

Table 1 summarizes PG&E's submitted cost forecast for the five components of the proposed Phase 1 PSEP, including both expense and capital costs of approximately $2.2 billion.

Table 1– Summary of PG&E Proposed IP Phase 1 Cost by Major Program ($ in Millions)[1]

	2011	2012	2013	2014	Total
Expenses Description					
Pipeline Modernization	122.7	94.9	87.3	102.8	407.7
Valve Automation	1.6	2.6	3.1	3.8	11.1
Pipeline Records Integration	55.7	88.1	32.4	7.2	183.4
Interim Safety Enhancements	-	1.0	1.1	1.1	3.2
Program Management Office	1.6	3.5	3.4	3.4	11.9
Contingency	39.1	41	27.5	25.6	133.2
Total Expenses	220.7	231.1	154.8	143.9	750.5
Capital Description					
Pipeline Modernization	32.8	228.9	310.5	355.9	928.1
Valve Automation	13.7	39.5	53.3	26.0	132.5
Pipeline Records Integration	7.4	42.3	27.2	25.7	102.6
Interim Safety Enhancements	-	-	-	-	-
Program Management Office	3.0	6.6	6.7	6.6	22.9
Contingency	12.0	67.0	82.6	85.7	247.3
Total Capital	68.9	384.3	480.3	499.9	1,433.4
Combined Cost Proposal					
Pipeline Modernization	155.5	323.8	397.8	458.7	1,335.8
Valve Automation	15.3	42.1	56.4	29.8	243.5
Pipeline Records Integration	63.1	130.4	85.7	32.9	286
Interim Safety Enhancements	-	1.0	1.1	1.1	3.2
Program Management Office	4.6	10.1	10.1	10.0	34.8
Contingency	51.1	108	110.1	111.3	380.5
Total Expense and Capital	**289.6**	**615.4**	**635.1**	**643.8**	**2,183.9**

The individual program components of PG&E's plan are detailed in the relevant sections below.[2] It is relevant to note at the outset that the scope of work, and costs, for the pipeline modernization component are based on a database populated in about April

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[1] PG&E Testimony, pages 1-16 and 1-17.

[2] My testimony does not address the Interim Safety Enhancements or the Program Management Office Components.

2011. This database will be modifi ed based on the results of the MAOP Validation, which will hopefully significantly reduce the necessary work if PG&E is able to locate some of its missing records.

1.2. Summary Of TURN's Recommendations

Based on my testimony, TURN recommends the following:[3]

<u>Pipeline Modernization</u>

- All segments in Class 2 locations be deferred to Phase 2 unless the segments are appropriately part of a higher priority project, impacting up to 40 miles scheduled for replacement and 157 for testing.
- Manufacturing Threats: PG&E should include DSAW pipe in its evaluation, but PG&E should attempt hydrotesting where possible, rather than jumping to replacement in Decision Step M2. This will impact a significant amount of the 100 miles scheduled for replacement. For pipes operating at <30% SMYS, PG&E can make greater use of leak survey monitoring before jumping to strength testing.
- Fabrication Threats: The Engineering Condition Assessment, or ECA, is insufficiently specified to allow an evaluation of whether it is appropriate. The decision tree also needs to be modified since hydrotesting is not the most appropriate evaluation tool for certain construction threats, such as girth weld connections.
- Corrosions Threats: The Decision Tree needs to be revised. For over 493 miles scheduled for testing due to the corrosion decision tree, I recommend that ILI is a better assessment tool if the pipe can be retrofit for piggability. I do not recommend relying on any of PG&E's past integrity management outcomes.
- Hydrotesting: The Commission should require PG&E to conduct actual high-pressure hydrotests, with a minimum pressure equal to or greater than 90% of SMYS.

<u>Valve Automation</u>

[3] As explained later, any quantitative recommendations are illustrative only, since PG&E's database of segments used to create the PSEP is not validated and will be significantly changed as a result of the MAOP validation process.

- In general, TURN does not agree with PG&E's use of the PIR as a primary criterion for selecting segments for valve automation and for prioritizing the valve automation program. A more detailed evaluation of pipeline rupture dynamics suggests that isolation blowdown time and pipeline diameter should be used in the decision tree process and the prioritization process.
- Phase 1 should focus on pipelines in Classes 3 and 4 with diameters of 24 inches or greater and should install ASV's so that maximum spacing does not exceed eight miles on all such large diameter pipe, resulting in a reduction of approximately 61 valves on smaller pipelines.
- PG&E should also, in Phase 1, automate valves in HCA Classes 1 and 2 spanning HCAs (i.e., identified sites) using the 8-miles maximum spacing criterion, installing ASVs on pipe with diameters of 24 inches or greater. PG&E has approximately 60 miles of Class 1 and 2 pipe greater than 24-inch in HCAs, resulting very roughly (based only on length) in an increase of sixteen valves in Phase 1.
- TURN recommends only ASVs on large pipeline. PG&E's contention that valves can be installed in either ASV or RCV mode and retrofitted later is troubling, since Accufacts' experience indicates that ASV design approaches should be significantly different than RCV design.
- Phase 2 should install ASVs or RCVS at a maximum spacing of eight miles on all pipelines les s than 24 inches spanning HCAs and Phase 3 should install valve automation on remaining low pressure transmission pipelines that are at risk of a full bore "leak failure" such as poor girth welds.
- While I do not object to PG&E's proposed SCADA enhancement program, based on my experience these proposals will most likely not improve emergency response time via a rupture, as the more important issues are control room emergency procedures, control room authority, and control room operating training and performance.

<u>Records Integration</u>

- I strongly object to PG&E's proposed Phase 2 and 3 "conservative assumptions" approach to validate the MAOP under §192.619(a)(1). For pipeline segments that were required to be strength tested either by industry standard, state or federal regulations and for which PG&E cannot now produce hydrotest records, such pipelines should be hydrotested or replaced, and the costs for such action should be borne by the shareholders.

- I do not object to the substance of the GTAM efforts provided that PG&E can demonstrate efficiency cost savings from the "new" centralized electronic database, that PG&E institutes sufficient quality control measures to ensure accurate data entry and data protection and that an audit is conducted.

Cost Recovery, Cost Responsibility and Cost Forecasting

- The Commission should not authorize any rates or revenues based on PG&E's cost forecasts, since the scope of work will change substantially due to significant revisions resulting from PG&E's ongoing MAOP validation process.
- Much of PG&E's plan reflects the need to bring the company into pipeline safety regulatory compliance because of past PG&E mismanagement practices with respect to records keeping and integrity management.
- Prudent pipeline operators maintain critical pipe information, especially records of strength testing. PG&E admits that it followed industry standards for strength testing and record retention since at least 1955. If costs have been included in PG&E's Pipeline Modernization Program because historical hydrotesting records cannot now be found or readily produced by PG&E, that additional cost to now bring the system into compliance should be borne by PG&E and its shareholders. Shareholders should bear the full responsibility associated with reestablishing confidence in MAOP for any pipeline segment within the system where hydrotesting was required and the records cannot now be found, including the full $162.3 million of costs for the MAOP Validation project.
- PG&E unreasonably relied on an unusually high amount of direct assessment, and very little use of ILI or hydrotesting, in the Baseline Assessments it performed to meet TIMP requirements, and PG&E significantly reduced its pipeline replacement work after 1999.
- PG&E's cost forecasts for hydrotesting appear high compared to my experience and published data.

2. Evaluation of the Pipeline Modernization Component

2.1. Detailed Summary of PG&E's Phase 1 Program, the Decision Tree Results and Database Issues

The CPUC ordered PG&E "to either pressure test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test."[4] In response to Commission directives, PG&E initially stated that it lacked pressure test records on approximately 600 miles of HCA pipeline, mostly due to the use of "619(c) documentation."[5] Table 2 is an estimate of the miles that would be assessed/replaced under the PG&E proposed Phase 1 effort that has a suggested scheduled for the years 2011 through 2014.

Table 2: PG&E's Proposed Project Modernization Phase 1 (2011 – 2014) miles and cost[6]

	Miles	Total Cost (in Millions $)	Cost/mile (millions $ /mile)
Pipeline Replacement Forecast	185.7	834.2	4.49
Pipeline ILI Forecast (upgrade and analysis)	233	39.99	.172
Strength Test Forecast (expense and capital)	783	411.3	.525
Total	1,201.7	1285.5	

In the Pipeline Modernization ("PM") component of the PSEP PG&E proposes to complete approximately 165 primary pipe replacement "projects" totaling about 185 miles of pipe replacement. It proposes to complete approximately 162 primary pipeline "testing" projects comprising approximately 783 miles of

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[4] D.11-06-017, p 17.

[5] PG&E Report in R.11-02-019, March 15, 2011, p. 13.

[6] PG&E Testimony, Table 3-3, page 3-63 and Table 3-4, page 3-64, and Table 3-5, page 3-65. The cost projections are PG&E's, and TURN does not concur with these unusually high or possibly skewed cost projections/estimates.

pipeline (see Table 3). These projects are detailed in the workpapers to chapter 3 of PG&E's testimony.

Each of the individual projects, however, is comprised of multiple line segments. PG&E has used the data in its GIS system to populate a "PSEP Database" containing information on each of approximately 25,000 pipeline segments. PG&E developed its scope of work by filtering the PSEP Database information through the decision tree. However, since pipeline segments do not neatly align with land use Class designations, the actual work targeted towards Class 3 locations will necessarily involve testing or replacing pipe segments in Class 2 or 1 locations. Whether PG&E correctly defined this work requires a close evaluation of each specific project. It appears that CSPD has conducted a sampling of exactly this type of evaluation for Sempra.[7] I have not conducted such sampling evaluation of PG&E projects.

PG&E used three decision trees to filter its database of segments so as to evaluate for the presence of three categories of threats: Manufacturing, Fabrication and Construction, and Corrosion and Mechanical Damage. Overall, PG&E's decision-tree process results in the following breakdown of Phase 1 work by threat category:

[7] CPSD, Technical Report Regarding the Sempra PSEP, January 17, 2012, p. 11-13.

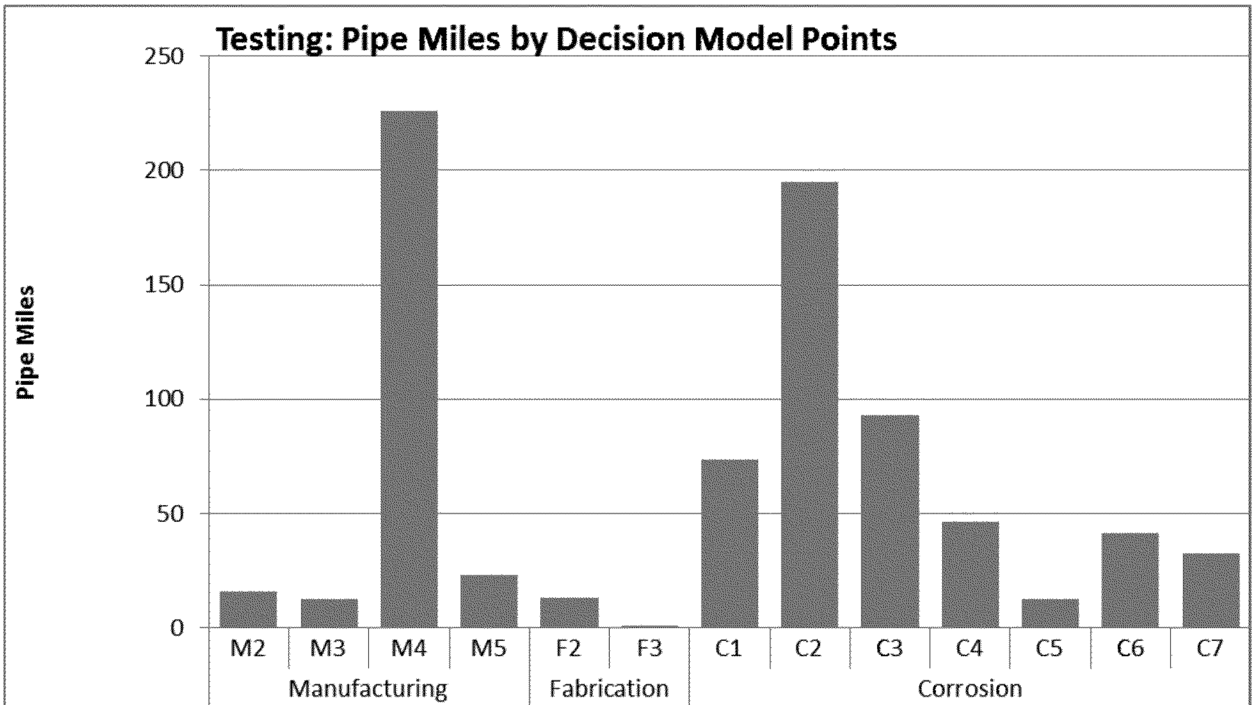
Table 3: Scope of Replacement and Testing Work by Threat Category

	Manufacturing and Construction	Fabrication and Construction	Corrosion and Latent Mechanical Damage	Grand Total
Replacement				
Segments	1996	133	643	2772
Pipe Miles	124	16	46	185
Testing				
Segments	954	60	2382	3396
Pipe Miles	276	13	494	783
Total Segments	**2950**	**193**	**3025**	**6168**
Total Pipe Miles	**400**	**29**	**539**	**969**

Even more specifically, PG&E's scope of work can be defined by the specific "action" boxes in PG&E's proposed decision trees which dictate the nature of Phase 1 work, as illustrated in Figure 1 and

Figure 2 and detailed in Table 4:

Figure 1: Number of Miles Scheduled for Strength Testing by PG&E's Decision Step Output



	M2	M3	M4	M5	F2	F3	C1	C2	C3	C4	C5	C6	C7
	Manufacturing				Fabrication		Corrosion						
Pipe Miles	16	12	226	23	13	0	73	195	93	46	13	41	32
Pipe Miles %	5.6%	4.5%	81.7%	8.2%	99.2%	0.8%	14.8%	39.5%	18.8%	9.3%	2.5%	8.4%	6.6%

Figure 2: Number of Miles Scheduled for Replacement by PG&E's Decision Step Output

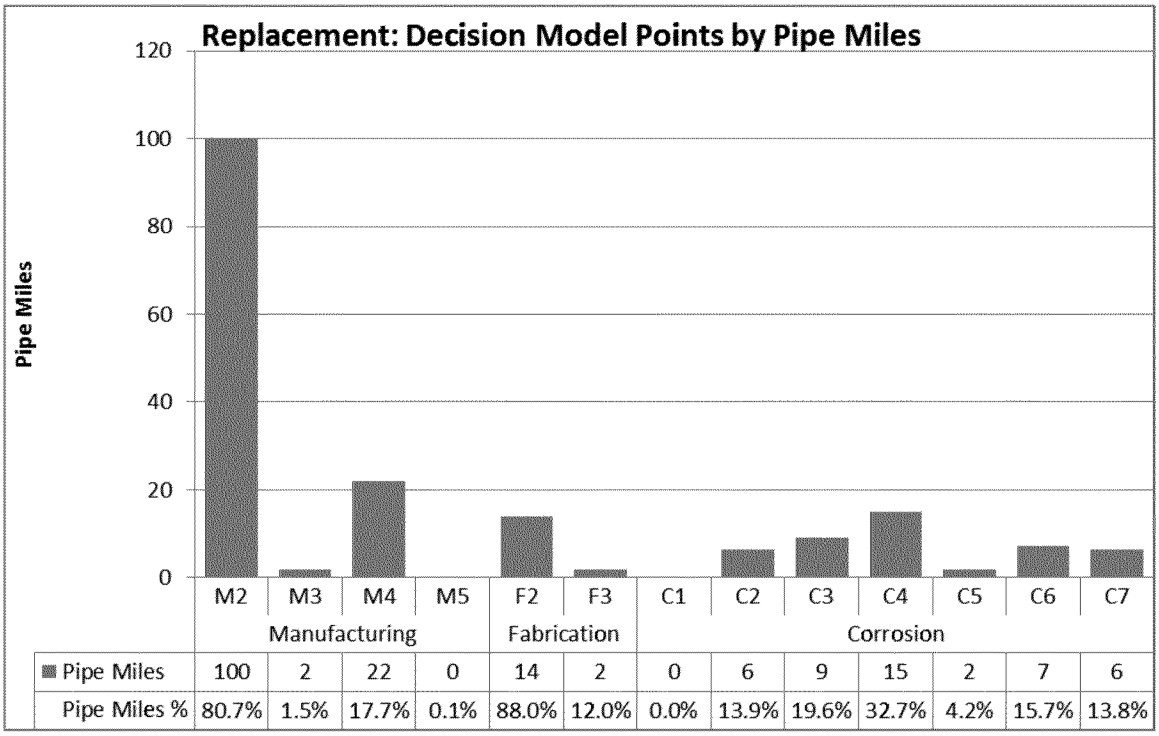


Table 4: Pipe Miles By PG&E's Decision Model Criteria and Class Location

	1		2		3		Total Pipe Miles	Total Pipe Miles %
	Pipe Miles	Pipe Miles %	Pipe Miles	Pipe Miles %	Pipe Miles	Pipe Miles %		
Replacement	**7.47**	**4.03%**	**40.39**	**21.78%**	**137.63**	**74.20%**	**185.50**	**100.00%**
Manufacturing	**3.52**	**2.84%**	**29.83**	**24.05%**	**90.68**	**73.11%**	**124.03**	**100.00%**
M2	1.53	1.53%	27.64	27.61%	70.93	70.86%	100.11	100.00%
M3	1.90	100.00%		0.00%		0.00%	1.90	100.00%
M4	0.01	0.04%	2.19	9.97%	19.74	90.00%	21.94	100.00%
M5	0.08	100.00%		0.00%		0.00%	0.08	100.00%
Fabrication	**2.32**	**14.65%**	**0.22**	**1.36%**	**13.29**	**83.99%**	**15.82**	**100.00%**
F2	0.42	2.99%	0.22	1.55%	13.29	95.46%	13.92	100.00%
F3	1.90	100.00%		0.00%		0.00%	1.90	100.00%
Corrosion	**1.64**	**3.58%**	**10.35**	**22.67%**	**33.67**	**73.75%**	**45.65**	**100.00%**
C1	0.01	100.00%		0.00%		0.00%	0.01	100.00%
C2	0.27	4.26%	0.46	7.20%	5.61	88.53%	6.34	100.00%
C3	0.00	0.02%	5.00	55.80%	3.96	44.18%	8.97	100.00%
C4	0.66	4.41%	3.61	24.20%	10.66	71.39%	14.94	100.00%
C5	0.37	19.13%	1.11	57.98%	0.44	22.89%	1.91	100.00%
C6	0.10	1.39%		0.00%	7.09	98.61%	7.19	100.00%
C7	0.23	3.60%	0.17	2.68%	5.90	93.72%	6.30	100.00%
Testing	**151.70**	**19.37%**	**157.90**	**20.17%**	**473.44**	**60.46%**	**783.05**	**100.00%**
Manufacturing	**35.66**	**12.91%**	**66.81**	**24.18%**	**173.83**	**62.91%**	**276.29**	**100.00%**
M2		0.00%	8.61	55.46%	6.91	44.54%	15.52	100.00%
M3	12.31	100.00%		0.00%		0.00%	12.31	100.00%
M4	0.65	0.29%	58.20	25.78%	166.92	73.93%	225.77	100.00%
M5	22.71	100.00%		0.00%		0.00%	22.71	100.00%
Fabrication	**0.32**	**2.50%**		**0.00%**	**12.64**	**97.50%**	**12.96**	**100.00%**
F2	0.22	1.75%		0.00%	12.64	98.25%	12.86	100.00%
F3	0.10	100.00%		0.00%		0.00%	0.10	100.00%
Corrosion	**115.72**	**23.43%**	**91.10**	**18.45%**	**286.98**	**58.12%**	**493.79**	**100.00%**
C1	73.22	100.00%		0.00%		0.00%	73.22	100.00%
C2	21.84	11.19%	50.63	25.94%	122.73	62.87%	195.20	100.00%
C3	0.53	0.56%	17.30	18.61%	75.17	80.83%	92.99	100.00%
C4	16.71	36.23%	17.38	37.68%	12.03	26.08%	46.12	100.00%
C5	1.32	10.53%	0.85	6.79%	10.39	82.68%	12.57	100.00%
C6	0.23	0.55%	0.33	0.80%	40.76	98.65%	41.32	100.00%
C7	1.86	5.76%	4.60	14.21%	25.89	80.03%	32.36	100.00%
Grand Total	**159.17**	**16.43%**	**198.30**	**20.47%**	**611.08**	**63.09%**	**968.55**	**100.00%**

PG&E's decision tree process is independent of the contents of its PSEP database. However, PG&E created its "programs" by searching its PSEP database using the decision tree process. All actual project definitions and costs will thus change as the underlying data is amended.

PG&E's PSEP program was based on a database last updated in April of 2011.[8] We know that PG&E's GIS database contains errors – unfortunately we don't know how many. PG&E has explained that the error in classification of the longitudinal weld on Segment 180 of Line 132 apparently originated in the transcription of information from a journal voucher into the pipeline survey sheets, which were then used to populate the GIS database.[9] The PSEP database contains a large amount of data deficiencies. For example, a significant amount of the mileage scheduled for hydrotesting contains segments that have been previously strength tested but have test pressures listed as zero, duration listed as zero, blank test dates or other incomplete records. Aside from outdated data, the PSEP database proved extremely difficult to manipulate because fields related to pressure testing and validation were populated at different times, leading to data inconsistencies.[10]

Indeed, PG&E expects that its ongoing MAOP validation process will results in "important updating of the records … that could change work scope or priority."[11] PG&E has already begun updating its database.[12] We expect that the changes in the work scope could be large. For example, PG&E originally forecast testing 152 miles of pipeline with characteristics similar to the San Bruno pipeline. However, during the course of the work in 2011 PG&E apparently "found and verified" pressure test records for 44.2 of the identified miles, so

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[8] PG&E Response to DRA DR 045-06(f), included in Attachments.

[9] CPSD San Bruno Report, January 12, 2012, p. 63-66.

[10] PG&E Response to DRA 045-03(c) and 045-05(c).

[11] PG&E Testimony, p. 6-3, lines 15-17.

[12] PG&E Response to DRA DR 045-02(b), included in Attachments.

PG&E hydrostatically tested only 102 miles.[13] This is obviously a very significant change in the originally forecast scope of hydrotesting work.

A couple of conclusions result from the "work in progress" nature of PG&E's data. First, the Commission should not authorize any specific scope of work or costs based on the quantitative data contained in PG&E's testimony and workpapers, since they are subject to significant revision. Second, the focus of TURN's analysis and testimony is on the qualitative deterministic analysis in the "decision tree." This analysis does not in and of itself depend on the underlying data.

Throughout this testimony, I provide some illustrative examples of numerical results and cost impacts of alternative recommendations for a decision tree matrix and for cost responsibility allocation. The numbers are meant to be completely illustrative. They are bound to change, since they are based on already outdated data. Moreover, the cost numbers use approximations of PG&E's actual costing methodology.

2.2. A Large Portion of PG&E's Transmission System is Located in High Consequence Areas

One of the most critical elements related to the potential harmful impact of an y pipeline failure is the population density in the area immediately surrounding a pipeline. This risk factor is addressed by the establishment of High Consequence Areas ("HCAs") which are defined by one of two methods chosen by the operator for each pipel ine segment: (1) a method that builds off the traditional concept of class locations, or (2) a method defining HCAs based solely on a Potential Impact Radius ("PIR") sweep around the pipeline. Both methods add an important consideration called "identified sites" to the HCA definition. Population density as measured by habitable buildings used to set class location does not account for other uses of land which result in the presence of persons near a pipeline. The "identified sites" definition attempts to capture locations

[13] PG&E Report, December 30, 2011, p. 2.

near a gas transmission pipeline with a high probability of large numbers of unsheltered individuals or difficult to evacuate structures, such as hospitals.[14]

Table 5- PG&E Transmission mileage by class location and HCAs[15, 16]

	Class 1	Class 2	Class 3	Class 4	Total
Transmission Miles	**3,509**	**580.3**	**1,721.5**	**3.7**	**5,814.5**
% of Total Miles	60.3	10.0	29.6	.06	100
HCA Mileage By Class	**51**	**29.5**	**943**	**3.7**	**1027**
% HCA Mileage By Class	5.0	2.9	91.8	.3	100

Table 5 summarizes how PG&E's transmission system reflects these human use factors. There still remains some question as to the accuracy of PG&E's information concerning class location and High Consequence Areas ("HCAs") given that there appears to be var iation in the reported numbers within the filing.

Table 5 illustrates that PG&E has an unusually high percentage of HCA pipeline in its gas transmission system – approximately 18%. Because the vast majority of gas transmission pipeline mileage in the U.S. is in sparsely populated areas

[14] 49CFR§192.903 – definition of *Identified site:* (a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

[15] Class location is mainly determined by the number/type of buildings intended for human occupancy in a 660 ft sweep on either side of a pipeline.

[16] From PG&E's response to TURN data request TURN_DR_008-Q01Atch01.

(mainly class 1), only about 6.6 % of the approximately 292,000 miles of total gas transmission pipelines in this country currently falls under the definition of HCAs.[17] The Table also illustrates t hat PG&E has a relatively high percentage of its entire transmission pipeline mileage – approximately 30% - as class 3.

One of the objectives of the federal pipeline safety gas transmission integrity management regulation was to capture "identified site s," even in low building density class 1 or class 2 areas, because of the relative low survivability should a gas transmission pipeline rupture in such sensitive locations where large numbers of unsheltered or difficult to evacuate people may gather. Given the high percentage of HCA mileage in PG&E's gas transmission system (containing the second largest miles of HCA in the nation, with Sempra containing the highest HCA mileage), the pipeline operators and the regulators should have given careful attention to compliance with federal integrity management rules that have been in effect for almost the past ten years.[18]

2.3. Evaluation of Threat Assessment Decision Trees

Keeping in mind the data limitations discussed above, Accufacts has reviewed Attachments 3A, Implementation Plan Pipeline Modernization Decision Tree," and 3B, "Decision Point Justification of the IP Pipeline Modernization Decision Tree." Our general observation is that the Decision Tree has important detailed "gaps" and serious misapplications as detailed below.

In summary, I recommend that:

- All segments in Class 2 locations be deferred to Phase 2 unless the segments are appropriately part of a higher priority project; this recommendation affects up to 40 miles scheduled for replacement and 158 for testing.
- Manufacturing Threats: PG&E should include DSAW pipe in its evaluation, but PG&E should attempt hydrotesting where possible, rather than jumping to replacement in Decision Step M2. This will impact a significant

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[17] P&GE Testimony, citing "PHMSA Gas IMP Reports as of June 30, 2010," page 2-15.

[18] Sempra Energy Utility handout at June 22 & 23, 2011 CPUC Technical Workshop (R11-02-019) indicating Sempra has 1,320 miles of gas transmission pipelines within HCAs, or 31% of their overall gas transmission pipeline mileage.

amount of the 100 miles scheduled for replacement to address manufacturing threats. For pipes operating at <30% SMYS, PG&E can make greater use of leak survey monitoring before jumping to any decision to strength testing.

- Fabrication Threats: The Engineering Condition Assessment, or ECA, is insufficiently specified to allow an evaluation of whether it is appropriate. The decision tree also needs to be modified since hydrotesting is not the most appropriate evaluation tool for certain construction threats, such as girth weld connections.
- Corrosions Threats: The Decision Tree needs to be revised. For the 493 miles PG&E is proposing to be scheduled for testing due to the corrosion decision tree (see Figure 1), I recommend that ILI is a better assessment tool if the pipe can be retrofit for piggability. Prudent leak survey analysis, however, will be a better assessment approach for the lower stress (< 30 SMYS) segments where corrosion/third party damage is the only threat of concern. I do not recommend relying on any of PG&E's past integrity management outcomes.
- Hydrotesting: The Commission should require PG&E to conduct actual high-pressure hydrotests, with a minimum pressure equal to or greater than 90% of SMYS.

2.3.1. Comments Applicable to All Decision Trees

The PG&E Decision Tree Steps 1L, 1K, 2G, & 3B includes class 2 location areas in the filtering analysis. Table 5 above shows that approximately 10% (580 miles) of PG&E's transmission system is class 2, but only about 30 miles of class 2 pipeline contain HCAs. As detailed in

Table 4, PG&E's PSEP includes over 40 miles of Class 2 for replacement, or fully 22% of the replacement miles. PG&E's PSEP includes over 157 miles of Class 2 for testing, or about 20% of the testing miles.

The explanation in the pipeline modernization plan given for including class 2 with the class 3 and 4 decision step (requested by CPSD), is neither clear nor defensible at this time.[19] The large additional effort (both expense and timing) resulting from the blanket inclusion of this additional mileage is not warranted, especially given PG&E's forecast of replacement costs per mile shown in Table 3 above.

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[19] PG&E Testimony, p. 3-36 (referencing a CSPD request for a "consistent use of Class 2 in the Phase 1 work scope").

Class 2 locations should be removed from the 1L, 1K, 2G, & 3B decision/evaluation points until PG&E can properly explain or justify the threat basis for including Class 2 locations. The current process approach should be driven by the Potential Impact Radius, or PIR, and will prove more consistent. The company has more than enough to deal with in their PM Phase 1 work scope, and their efforts should rightly focus on the highest populated areas and higher risk pipelines first. There may be small segments of class 2 pipeline segments that might warrant incorporation into the Phase 1 PM effort, but such inclusion should be based on their realistic near future (Phase 1 - 2012 through 2014) potential to become HCAs.

2.3.2. Manufacturing Threats

DSAW Pipe

The PG&E Decision Tree step 1D could be interpreted to suggest that DSAW is not "a manufacturing threat" o n PG&E's transmission system. However, DSAW pipe failures associated with seam failure have occurred that indicate there are seam risks associated with such pipe, even on gas transmission pipelines.[20] Given the problems associated with DSAW on gas transmis sion systems and the serious gaps or errors in the GIS, TURN recommends that DSAW should not be included in Step 1D , but that DSAW pipe should be included in Step 1H. The result is that DSAW pipe would be a candidate for the modified Steps M4, M2, or M5 as indicted below.

However, as discussed below, I recommend that any such DSAW pipe be subject to a strength test rather than replacement.

Pipe Replacement and Step M2

The PG&E Proposed Decision Tree process appears to result in an unusually high and disproportionate number of miles for pipe replacement. The decisions to replace need a

[20] PHMSA Workshop presentation to Joint Technical Advisory Committee, "Managing Challenges with Pipeline Seam Welds and Improving Pipeline Risk Assessments and Recordkeeping," August 2, 2011, slide 11 showing gas line Pipe Seam Failures (2002-2010) by Seam Type including nine DSAW failures.

further additional step that summarizes, for a particular pipeline segment, what critical factor or factors led to the decision to replace a particular pipeline segment.

For example, over 100 miles of replacement result from PG&E's Decision Tree Step M2. Step M2 results in a decision to replace large diameter (during Phase 1) Urban pipe with manufacturing threats that operate at >30% SMYS. Step M2 should be modified to s ay. "Reduce Pressure & either Strength Test or Replace in Phase 1." If the line can survive a prudent hydrotest the extreme of replacement for seam weld threats needs to be specifically justified. Before proceeding to a replacement decision other steps s hould be added asking or indicating what critical factor(s) drive to replacement over hydrotesting or ILI? For example does the pipeline segment contain at -risk manufacturing seam factors that hydrotesting or ILI cannot adequately assess? And more import antly is there a problem with the pipeline segment that has led PG&E to determine that a specific pipe segment would experience numerous hydrotest failures that would justify pipe replacement? Could the pipeline be rationally shutdown for hydrotesting or ILI conversion? (if not, then pipe replacement may be warranted).

The key point is that there are plenty of transmission pipelines across the country containing manufacturing threats, and operating well above 30% SMYS; and most of this pipe has not needed the extreme step of pipe replacement because it was prudently hydrotested.

New pipe is not necessarily better than old pipe, especially if the pipeline operator cannot assure qualify control and quality assessments throughout the manufacture, transpor tation, or construction phases of new pipelines that have been especially problematic in recent pipeline new construction. [21] 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

[21] See PHMSA WorkShop on New Pipeline Construction issues at http://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=58&nocache=5323

summarize such important qualifiers that would further support or justify the extreme of pipe replacement.

TURN believes the majority of pipeline meeting step M2 should be able to be hydrotested. Step M2 in PG&E's plan results in 100 miles of pipe replacement. I estimate that a very high percentage of this pipe, on the order of 95 +%, or 95 plus miles, would pass a prudent hydrotest and should not be replaced.

<u>Step M5</u>

Step M5, addressing pipe segments in non-HCAs or rural areas that are most likely to fail as leaks, should be modified to say : "Perform special leak survey monitoring on pipe segments." A pressure reduction and strength test are inappropriate and unwarranted for Manufacturing Threats at this step.

<u>Step M4</u>

Step M4, addressing pipe segments in HCAs or urban areas that are most likely to leak, should be modified to say. "Perform special leak survey monitoring on pipe segments." A fatigue analysis, replacement, ILI, or strength test is inappropriate and unwar ranted for Manufacturing Threats that can only fail as leaks in urban areas, unless these segments are part of a segment that can be contiguous with HCAs where efficiency of assessment may be warranted.

2.3.3. Fabrication and Construction Threats

<u>Step 2C and ECA</u>

The Engineering Condition Assessment ("ECA") proposed in Decision Tree Step 2C is not adequately explained, and thus we cannot evaluate whether PG&E's planned work is sufficient to address fabrication or construction threats. PG&E's response to TURN was that “PG&E does not have an Engineering Condition Assessment (ECA) procedure in place for the Pipeline Safety Enhancement Program, but is working to develop an acceptance criterion to assess the condition of the Decision Tree refe renced antiquated or abnormal pipe joints, girth welds, angle points, or other fittings.”[22] There is too much left to the discretion of the operator to ensure that this threat category will be adequately addressed or resolved if the operator is left to make this important decisi on on their own. Citing industry standards or the explanation that PG&E is planning to work with experts without providing sufficient detail to permit an independent review is an unsatisfactory response. More specifically, ASME B31.8S -2004 which is speci fically referenced in federal pipeline safety integrity management regulations, only permits ECA in “some defects,” related to third party damage, manufacturing and construction welding, <u>not</u> in most of the situations defined in step 2B.[23]

<u>Step 2F and Assessment with Abnormal Loading Analysis</u>

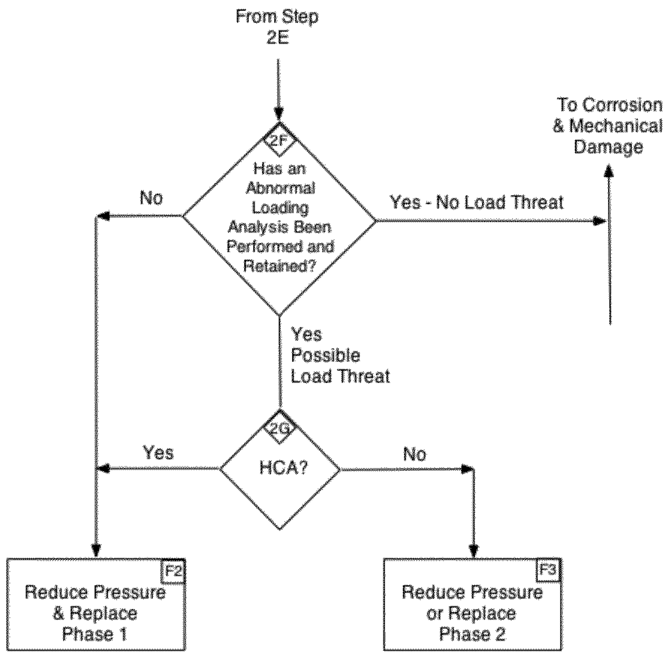
The Decision Tree Step 2F overstates the value of a hydrotest to the specific threats identified in 2E. Accordingly, 2F, 2G, F2 and F3 need to be reconfigured as hydrotesting is not the appropriate assessment tool for the threat categories identified in 2E. Hydrotesting is not the most effective assessment tool to test girth welds and other connections because of the lower hoop stresses.

TURN proposes that steps 2F, 2G, F2 and F3 be repla ced as indicated in Figure 3. This alternate decision tree introduces another step to determine whether an “abnormal loading analysis” has been performed. Segments w here the abnormal loading analysis has shown that there are no load threats can pass the Fabrication and Construction Threats tree , but should be added to a list of segments that PG&E should periodically monitor in their right-of-way program to assure the abnormal loading threat conditions haven’t changed.

Figure 3: TURN’s Proposed Flow Diagram Replacing Steps 2F, 2G, F2 & F3 in PG&E Pipeline Modernization Decision Tree

[22] PG&E response to TURN DR 008-03, included in Attachments.

[23] ASME B31.8S-2004, Table 4, “Acceptable Threat Prevention and Repair Methods,” p 22, included in Attachments.



Such abnormal loading analysis that can identify a pipeline segment's potential to physically separate at a pipe connection is critical, especially in HCAs where pipe segment connections from past industry practices, such as certain girth welds are "poor." Abnormal loading analysis pertaining to poor joining past practices should be complete, well documented, and be retained for the life of the pipeline, while each threat pipe segment remains in service.

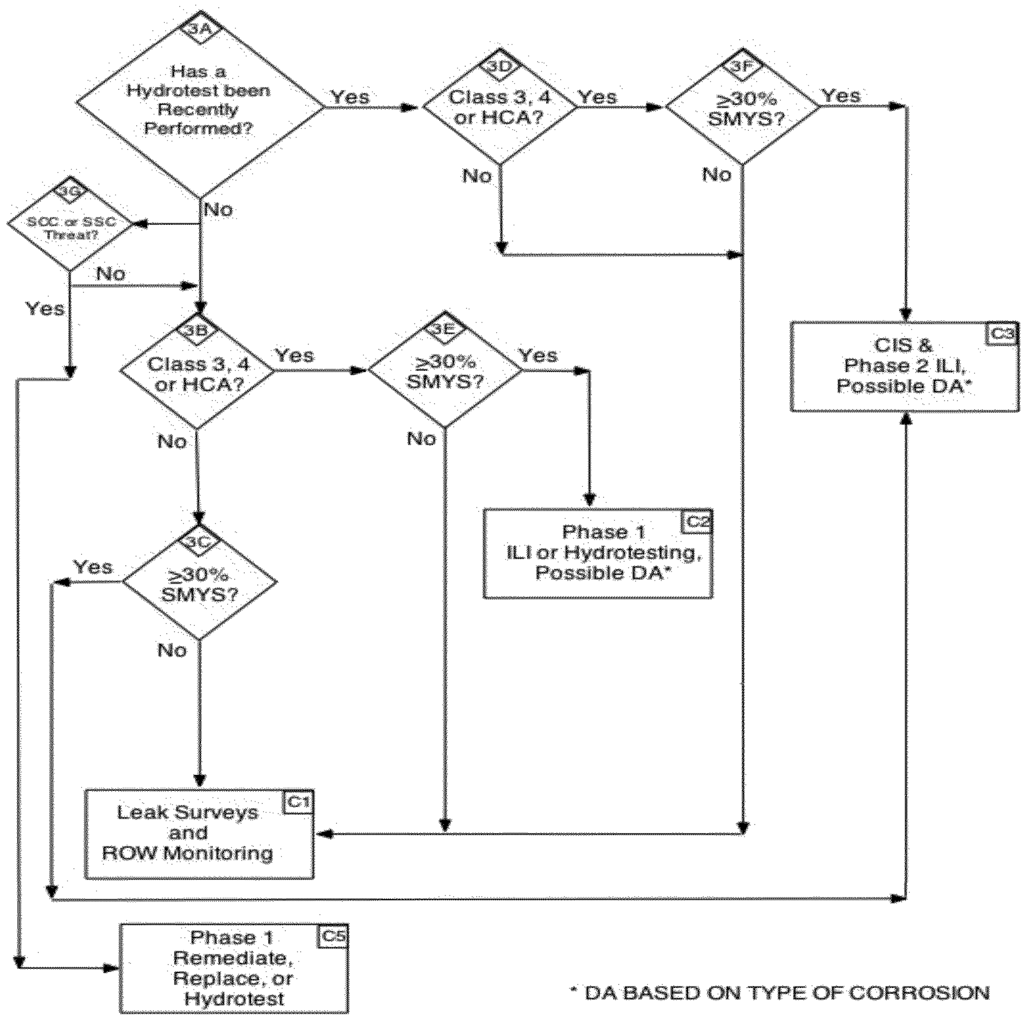
2.3.4. Corrosion and Mechanical Damage Threats

<u>Step 3A – No need to hydrotest for Corrosion Threats</u>

Given the nature of this threat family to cause time dependent pipeline failure (either leak or rupture), a previous Subpart J strength test, especially performed some years in the past, has little benefit in filtering out these risks of failure because a prudent hydrotest's intent is to take an existing at -risk anomaly to failure. PG&E's proposed Step 3A is thus incorrectly framed , as a hydrotest will not identify corrosion or mechanical damage threats introduced after the hydrotest. In addition, given the problems associated with PG&E's incomplete and inadequate integrity management program, we p lace little credit in its past program to address even the threats identified as "Corrosion & Latent Mechanical Damage Threats," and as a result TURN recommends not incorporating the BIAP step (step 3D) in PG&E's Decision Tree which is highly and o verly dependent on DA (see Table 10).

Figure 4 is TURN's proposed flow diagram for this threat category that we believe is more appropriate and that should replace PG&E's PM Decision Tree for pipeline segments containing only this family of threats. Comparing Figure 4 to PG&E's Attachment 3A illustrates another problem when approaching pipeline threats utilizing a sequential flow diagram method. The conclusion may not make sense (such as suggesting hydrotesting or ILI for transmission pipelines that are much more likely to leak, rather than rupture), or might miss important threat considerations, such as Stress Corrosion Cracking, ("SCC"), or selective seam corrosion, ("SSC"), specialized forms of selective corrosion that usually

Figure 4: TURN's Proposed Decision Tree for Corrosion and Mechanical Latent Damage



results in transmission pipeline ruptures. Such selective corrosion can have serious consequences if not properly considered in the context of the pipeline system's TIMP, especially for older poorly coated pipelines. Note that if SCC is suspected/found, the only assessment method to reliably assess this threat is a high-pressure hydrotest, not ILI.[24] ILI technology cannot at this time confidently identify this very serious threat that can go to rupture.

<u>Step C1</u>

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[24] ASME B31.8S-2004.

PG&E's Decision Tree Step C1 (nonurban areas that have never been subpart J hydrotested but have only the threats of gener al corrosion or third party damage) should follow TURN's Step 3C, the decision step as to whether the non Urban line is operating > 30% SMYS. For such lines operating greater than 30% SMYS an ILI or hydrotest may be appropriate, though the timing could be at a later Phase 2, given the lower population density. Hydrotesting may be superior to ILI if third party damage is the greater threat on a pipeline segment than corrosion. CIS effectiveness can also be overrated, depending on the type of coating on each pipeline, and other environmental conditions for example.

For pipelines in this threat category operating <30% SMYS, assessment approaches utilizing Strength or ILI inspection are not necessarily cost effective, given that the line segments would most likely fail as "gas leaks" on a transmission pipeline. A more cost effective approach would be the incorporation of additional proper leak surveys and right -of-way monitoring (See TURN proposed Step C1), which are properly analyzed, evaluated and reported to identify any particular increased risk leak trends for this category on the specific pipeline segments.

PGE's Step C1 results in the testing of about 73 miles of pipeline in Phase 1, which could be reprioritized or evaluated by leak surveys.

<u>Step C2</u>

PG&E's Decision Tree Step C2 (urban areas that have not been subpart J hydrotested but operate at >30 SMYS and have only the threats of corrosion or third party damage) includes pipelines that could rupture from these threats so these pipeline segments sh ould be evaluated in Phase 1. ILI is the preferred and superior method over hydrotesting to evaluate general corrosion threats in a cost effective manner, provided the cost to convert to allow ILI inspection are not prohibitive (ILI size will be a factor as there are limits for smaller diameter pipelines). Hydrotesting should be considered for those pipelines where ILI conversion cannot occur. In Figure 4 step C2, TURN has also permitted the application of DA in those very limited cases where this assessment would be appropriate, which will not be on many pipeline miles.

PG&E's Step C2 results in hydrotesting almost 200 miles of pipeline. At this time, I cannot determine how many of these miles will be candidates for retrofittin g and pigging, though an analysis by pipeline size would be the first step.

Step C3

PG&E's Decision Tree Step C3 (urban areas that have not been subpart J hydrotested but operate at <30 SMYS and have only the threats of corrosion or third party damage) utilizing Strength or ILI inspection is overkill and unduly expensive, given that the line segments risk of failure is from "gas leaks" on a transmission pipeline, not likely ruptures. PG&E's Step C3 results in the testing of over 90 miles of pipe. If the l ine can be reasonably converted to ILI, ILI would be the most technically safe and cost effective approach to track corrosion and most third party damage risks. If the pipeline segments cannot be reasonable converted to ILI, a more cost effective approach , however, would be the incorporation of additional and proper leak surveys, which are properly analyzed to identify any particular trends for this risk category, as well as additional right -of-way monitoring to help identify third party damage threats on the specific pipeline segments (see TURN's step C1).

Step 3D

In attachment 4, TURN has removed the Decision Tree Step 3D, as the reliance on improper and incomplete DA approaches or misapplication of DA in the past integrity management program, gives us little confidence that PG&E's BIAP has or is adequately addressing this threat category, even for corrosion threats. TURN proposes to change step 3D to a class 3 & 4 or HCA decision as shown in our revised decision tree.

Step C4

For PG&E's Decision Tre e Step C4 (urban areas that have been subpart J hydrotested, but operate at >30 SMYS and have only the threats of corrosion or third party damage), because of the potential to go to rupture, and the superior technical capabilities of ILI over hydrotesting in identifying most corrosion and third party damage threats, ILI is the preferred method of assessment. A recent strength test buys the operator some time to failure, so TURN is recommending a use of Close Interval Surveys ("CIS") to help monitor performance of external corrosion during Phase 1 and a move to ILI in a Phase 2 effort to assist in corrosion and mechanical damage assessment, unless ILI conversion costs are prohibitive or the line is too sm all in diameter for ILI. In C3 of TURN's decision tree, TURN has also permitted the application of DA in those very limited cases where this assessment would be appropriate, which will not be on many pipeli ne miles. PG&E includes about 46 miles for hydrotesting from Step C4.

Step C5

For PG&E's Decision Tree Step C5, utilizing strength or ILI inspection is unwarranted, given that the line segments should most likely fail as "gas leaks" on a transmission pipeline. A more cost effective approach would be incorporation of additional and proper leak surveys and right-of-way monitoring, which are properly analyzed to identify any particular trends for this risk category on the specific pipeline segments. TURN is recommending for this risk category step C1 as indicated in

Figure 4. TURN is basically recommending for non urban areas, as well as urban areas both operating at < 30% SMYS step C1, that efforts be focused on leak monitoring/evaluation and prudent right-of way monitoring, unless these segments can cost effectively be converted to ILI over time.

Because of the higher potential of Stress Corrosion Cracking ("SCC") and Selective Seam Corrosion ("SSC") to fail as rupture on a gas transmission pipeline, the Decision Tree should include specific evaluation for these selective corrosion threats. TURN has incorporated Step 3G into our proposed decision tree (

Figure 4). I have little confidence in PG&E's past integrity management approach which dismisses these threat categories, for example, because of PG&E claims that they have not experienced or found evidence of SCC, especially given this operator's past inability to adequately identify/address/evaluate in their past TIMP many potential threats on their system that could go to rupture.

In TURN's Decision Tree, Decision Tree Steps 3F, 3G, C6 and C7 have been removed as they do not adequately deal with what is needed, especially given the past state of incompleteness on many fronts of PG&E's past IM program.

2.4 Issues Related to Hydrotesting Procedures

There are two issues related to hydrotesting parameters that should be addressed – the nature of the hydrotests used in the decision tree screening process, and the operational characteristics of the future hydrotests that PG&E will conduct.

2.4.1 Use of "Sub-part J" as a Selection Criterion in Decision Tree

The first issue concerns the selection and prioritization of segments for future testing, replacement or evaluation. PG&E's Decision Tree Steps 1H, 2F, & 3A all ask "has a sub-part J strength test been conducted?" Sub-part J of the code primarily specifies that a pressure test should have an 8 -hour duration. It states nothing about minimum or maximum pressures. Sub -part 192.619(a)(2)(ii) of the federal pipeline safety regulation specifies minimum allowable ratios for setting the MAOP based on a hydrotest.

In its decision ordering these implementation plans, the Commission explicitly stated that PG&E should test or replace pipelines "which were not pressure tested or lack sufficient details related to performance of any such test."[25] The decision makes clear in several places that a hydrotest is one assessment method that meets "all elements required by the regulations in effect when the test was conducted," and that for pre-1961 (GO 112) hydrotests, the minimum acceptable test duration is one hour.[26]

[25] D.11-06-017, p. 19.

[26] D.11-06-017, Conclusion of Law 3.

PG&E should be using a filter that tests for a valid hydrotest based on the CPUC directive. To the extent "sub-part J" refers to the CFR, it is both overly restrictive and possibly underinclusive. However, the reality is that PG&E is apparently not screening for an 8-hour "sub-part J" hydrotest.[27] PG&E's decision tree filter apparently determines whether the test pressure met the required ratio for the class location and whether it contains four relevant test parameters. However, PG&E treated any segments with "blanks" – meaning no validation performed – as if they contained all necessary information. The screening filter does not consider test duration at all.

PG&E needs to ensure that pipeline with valid historical strength testing is not prioritized for Phase 1 work. It is too confusing to attempt to quantify at this point how much of the forecast work might be avoided in Phase 1.

2.4.2 PG&E Should Use High Pressure Hydrotests in the Future

The second issue concerns PG&E's future hydrotests. As noted above, sub-part J does not specify minimum or maximum test pressures. In fact, Subpart J is silent as to the test requirements related to an important pipeline variable, the range of SMYS (minimum and maximum) for a hydrotest and also does not identify minimum requirements for spike testing on gas transmission mainlines. The Urgent Safety Recommendation issued by the NTSB identified additional testing parameters for a hydrotest, to "determine the maximum allowable operating pressure with a spike test followed by a hydrostatic pressure test. (P-10-4)."[28, 29]

TURN is extremely concerned that PG&E is conducting "low-pressure" hydrotests which will fail to identify all actual threats, especially manufacturing seam threats. The result will be a lower rated MAOP, and the continued

[27] PG&E Response to DRA 045-04 and 045-05, included in Attachments.

[28] NTSB "Urgent Safety Recommendation P-10-02," dated January 3, 2011.

[29] Strength test for a pipeline can be either with gas or water. Because of the highly restrictive application on gas testing, strength tests for this testimony generally mean a test with water, or a hydrotest, unless specifically noted otherwise.

existence of unknown threats that could become problematic or fail in the near term. TURN recommends that all future hydrotest s set a minimum parameter of 90% SMYS ("high -pressure hydrotest"). For recent hydrot est that have been performed at lower pressure minimum thresholds than 90% SMYS, TURN advises that these recent pipeline segments incorporate a pressure cycle monitoring analysis and program to assure remaining seam imperfections left in these specific low -pressure hydrotest test segments don't quickly grow to a near term rupture failure from pressure cycling associated with day to day operating pressure changes.[30]

For example, a pipeline operator can perform a low -pressure subpart J test that may underst ate the potential MAOP for the particular grade of pipe. Low -pressure hydrotesting to obtain reduced MAOPs suggests that the operator may be trying to avoid prudent hydrotest failures that may be indicative of more systemic issues or risks that need to b e identified in certain segments, such as manufacturing seam threats. Low-pressure hydrotests do not permit the operator to fully utilize the pipe to its greatest efficiency resulting from higher operating pressures that even old pipe should easily withst and, especially given the trouble and costs of performing a hydrotest. [31] This gap or omission in U.S. federal Subpart J regulations can easily be identified by requiring minimum and maximum hydrotest pressures be reported in psig and as a percentage of SMY S for each segment tested. It is notable that other count ries have included critical

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[30] John F. Kiefner and Michael J. Rosenfeld, "Effects of Pressure Cycles on Gas Pipelines," GRI-04/0178, September 17, 2004.

[31] For example, for a fifty year old 30 inch, X-42 grade, 0.375 inch thick pipeline in a class 3 area location (design factor – 0.5), the design pressure, or MAOP = (2 x 42,000 x 0.375/30 in) x 0.5 x 1 x 1 = 525 psi. If a hydrotest on such a pipeline segment establishes an MAOP lower than 525 psi, something else is limiting the pipeline segment to contain pressure and this limitation needs to be clearly identified.

additional hydrotest parameters in their specific county's pipe safety regulations.[32]

TURN is also concerned about the impact of low-pressure hydrotesting on PG&E's nee d for capital expenditures associated with capacity expansions. For the past twelve years at least, PG&E has requested increased capital expenditures on its local transmission system based on capacity needs to serve growing load in the Sacramento and Central Valley areas. These needs were supported by engineering analyses, which were presumably based on the MAOP capacities of existing pipelines. TURN wonders whether PG&E's analyses and plans have been skewed by the unusually low MAOPs that are prevalent on its system.

PG&E has adopted a policy of not performing spike tests if they may result in a pressure exceeding 100% SMYS. TURN recommends the Commission reject this policy, based on the conclusions of PG&E's own hydrotesting expert and extensive evidence in the public domain clearly allowing such high -pressure hydrotesting.

PG&E testified under cross examination that hydrotesting pressures should never exceed 100% SMYS " [b]ecause you do not want to change the material characteristics of the metal involved , which in fact if you do stress, overstress it, it actually begins to change mechanically the composition of the metal ."[33] High-pressure hydrotesting has been an accepted practice for many years, provided certain testing protocols, not incorporated in fed eral pipeline safety regulations, have been implemented.

[32] Countries such as Canada, the United Kingdom, and Australia incorporate more specific requirements than the U.S. into their hydrotesting procedures to assure a prudent high-pressure hydrotest.

[33] Transcript of Hearing in R.11-02-019, 9/19/2011. Testimony of PG&E witness Jane K. Yura, pp. 31.

Indeed, in a letter to Ms. Jane Yura dated September 10, 2011, PG&E's own consultant has explained the uses of a spike test:

> The spike test was initially developed as a mitigation technique for stress-corrosion cracking (SCC). In that application, the spike pressure level is generally in the range of 105% to 110% of SMYS, while the hold for leaks is between 90% and 100% of SMYS. The spike test used to prove the integrity of some older vintage ERW seams that have exhibited a tendency to fail at levels above the mill test pressure is usually limited to around 90% to 95% SMYS (if a successful test at that level can be achieved) while the hold period to check for leaks is reduced 5% to 10% from that level. The final MAOP is established by the minimum required test pressure ratio with respect to the hold period in accordance with the regulations."

Mr. Rosenfeld detailed situations where a spike test might be appropriate, and concluded that "The NTSB's recommendation to conduct spike testing is reasonable within the suggested scope, but it cannot be generalized to all testing situations."[34] Mr. Rosenfeld emphasized that the most important variable is the ratio of test pressure to operating pressure.

In ad dition, PG&E has indicated that maximum hydrotest pressures have also been limited for other various reasons some without merit. PG&E states, " These tests included engineering variables such as significant elevation, which would cause the maximum pressure with a spike test to exceed 100% of the specified minimum yield strength of a pipeline,..."[35] The field solution is obvious, where elevation changes would cause significant pressure differences – the pipe should be segmented to allow shorter elevation differences to meet pre-establish hydrotesting parameters. In sum, TURN finds the reasons for not performing prudent high-pressure hydrotest without technical merit.

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[34] Kiefner & Associates, Inc., Letter from Michael Rosenfeld to Jane Yura, September 10, 2011; Provided as response to DR_CCSF_001-Q05Atch02.

[35] Report of Pacific Gas and Electric Company on Status of Hydrotesting Pressure Testing as of December 30, 2011, p 4. 12/30/2011.

In fact, it wasn't until PG&E's hydrotesting was brought more in line with the NTSB safety re commendations for a spike test that PG&E actually experienced two important but unrelated hydrotest major failures on different segments of their pipeline system.[36]

The pipeline operator, the public, and its ratepayers interests are best served by performing hydrotests on gas transmission mainlines that are in excess of the minimums required or defined in Subpart J or 49CFR§192.619. This is especially important given the expenses and coordination challenges claimed by PG&E to perform such important hydrotest assessments.

In Summary for each future hydrotest:

1) Each hydrotest minimum and maximum hydrotest pressures should be reported as psig and % SMYS.
2) All hydrotests should be tested at a minimum of 90% SMYS.
3) Spike testing should be required as a matter of course.
4) Reasons for limiting a specific hydrotest to 100% SMYS, not performing a pressure test to a minimum of 90% SMYS, or for not performing a spike test, before a test is performed, should be identified and evaluated as to their justification and such justification retained for the life of the hydrotest record.

3. Evaluation of the Valve Automation Component

3.1. Summary of PG&E's Valve Automation Proposal and TURN's Recommendations for Modifications

PG&E uses two decision trees to determine valve automation, d epending on whether a pipeline segment crosses an earthquake fault or not. TURN does not recommend any changes to PG&E's program segments crossing earthquake faults.

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[36] PG&E December 30, 2011 Report discusses the hydrotest failures and explains that they occurred "during the spike test," at pressures equal to 94.9% and 52.2% of SMYS.

For pipeline segments not crossing earthquake faults, PG&E intends to automate valves for all segments in Class 4 areas. [37] PG&E also intends to automate Class 3 segments that meet either one of two conditions: 1) PIR>200 feet, or 2) more than 50% of the Class 3 segment is in an HCA and the PIR>150 feet. PG&E's decision trees do not address valve automation for HCAs in Class 1 or 2 locations.

For all Class 3 segments meeting either of these two criteria, PG&E further uses the: 1) PIR value, and 2) HCA designation, to prioritize whether the valves will be automated in Phases 1, 2A or 2B. [38] In Ph ase 1 PG&E intends to automate valves in Class 3 and 4 locations with a PIR greater than 300 feet, containing "sustained segments" of at least five miles and at least 50% HCAs between existing valves.[39] This results in Phase 1 including approximately 230 v alves for automation, covering about 30% of PG&E's HCA mileage in Class 3 locations.[40, 41]

Although PG&E does not target any valves on segments in Classes 1 and 2, it appears that substantial mileage in Class 1 and 2 will be automated, probably due to the scattering of Class 3 segments near Class 1 and 2 locations, and the locations of existing valves. TURN does not believe, however, that Class 1 and 2 higher risk identified sites defined as HCAs are specifically addressed by PG&E's program.

PG&E adopts the federal regulatory maximum spacing for Class 3 locations of eight miles for determining valve spacing in either Class 3 and 4 locations. It is

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[37] PG&E Testimony, p. 4-11, Figure 4-3. While PG&E uses a PIR>100 feet as a cutoff criterion, it states that all Class 4 pipe segments, currently 1.5 miles of pipeline in PG&E's system qualify under this criterion (PG&E Testimony, "Table 4-3, "Pipe Miles by PIR, Class, and HCAs," page 4-17). Response to TURN DR_TURN_008-Q01Atch01 indicates 3.7 miles of Class 4 pipe.

[38] PG&E Testimony, Table 4-3, p. 4-38.

[39] PG&E Testimony, p. 4-39.

[40] PG&E Testimony, Table 4-4, p. 4-39.

[41] PG&E Testimony, p. 4-38 and Table 4-3.

unclear what spacing, if any, PG&E adopts for segments that will be automated in Class 1 and 2 locations.

TURN recommends the following modifications to PG&E's selection and prioritization process:

- In general, TURN does not agree with PG&E's use of the PIR as a primary criterion for selecting segments for valve automation and for prioritizing the valve automation program. A more detailed evaluation of pipeline rupture dynamics suggests that isolation blowdown time and pipeline diameter should be used in the decision tree process and the prioritization process.
- Phase 1 should focus on pipelines in Classes 3 and 4 with diameters of 24 inches or greater and should install ASV's so that maximum spacing does not exceed eight miles on all such large diameter pipe, resulting in a reduction of approximately 61 valves on smaller pipelines.
- PG&E should also, in Phase 1, automate valves in HCA Classes 1 and 2 spanning HCAs (i.e., identified sites) using the 8-miles maximum spacing criterion, installing ASVs on pipe with diameters of 24 inches or greater. PG&E has approximately 60 miles of Class 1 and 2 pipe greater than 24-inch in HCAs, resulting very roughly (based only on length) in an increase of sixteen valves in Phase 1.
- TURN recommends only ASVs on large pipeline. PG&E's contention that valves can be installed in either ASV or RCV mode and retrofitted later is troubling, since Accufacts' experience indicates that ASV design approaches are significantly different than RCV design.
- Phase 2 should install ASVs or RCVS at a maximum spacing of eight miles on all pipelines less than 24 inches spanning HCAs and Phase 3 sho uld install valve automation on remaining low pressure transmission pipelines that are at risk of a full bore "leak failure" such as poor girth welds.

- While I do not object to PG&E's proposed SCADA enhancement program, based on my experience these proposals most likely will not improve emergency response time via a rupture, as the more important issues are control room emergency procedures, control room authority, and control room operating training and performance.

3.2. PG&E's Focus on the Potential Impact Radius (PIR) as the primary selection criterion is Not Appropriate

3.2.1. PG&E testimony does not accurately reflect the complex transient dynamics of gas transmission pipeline rupture releases.

Gas transmission pipeline ruptures are typically dual full -bore venting releases from both ends of the open pipe caused by the pipeline's rupture. Such full -bore transmission pipeline ruptures, especially for large diameter pipelines, usually result in massive craters, ejection and fragmentation of pipeline steel and, typically, self-ignition of massive, highly turbulent gas clouds. The gas clouds don't dissipate quickly, driven mainly by the time it takes to close valves spanning the rupture. The "isolation blowdown" time of a pipe segment is the time necessary to vent out the full bore end of a ruptured pipeline segment once an isolation valve is closed. This isolation blowdown time is mainly established by a) the valve distance from the rupture, b) the diameter of the pipeline, and c) the initial pressure at the time of rupture.

Photo 1 is a picture of a 40 -inch gas pipeline rupture in which the photo was taken quite some time after the pipe ruptured. Photo 2 is an aerial view of the San Bruno pipeline rupture fire also taken quite some time after the actual pipe rupture.[42] In various PG&E testimonies it has been implied that gas transmission pipeline rupture fires quickly dissipate after a rupture event or "that the heat intensity at 15 minutes corresponds to a radius of approximately 60 percent of the initial PIR value."[43] In addition, credit is often implied for the pressure decay

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[42] NTSB Report, Accident Report NTSB/PAR-11/01, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010," adopted August 30, 2011, p. 3.

[43] PG&E Testimony, p. 4-17.

quickly in gas pipelines following rupture. [44] As discussed further below, credit for pressure decay should be very carefully reviewed as such factors may not apply to many gas transmission pip eline ruptures, especially as it relates to the actual heat flux released for large diameter pipeline ruptures. Photos 1 and 2 provide examples showing that ruptures are much more complex than PG&E's submitted testimony would suggest. In ruptures, gas vents at the speed of sound in the gas out of both ends of the open failed pipe (at approximately 900+ mph, accounting for the very loud roar heard during such events). The resulting dual gas jet can produce huge highly turbulent gas clouds that generate l arge very high heat flux burning clouds that can also undergo multiple re -ignitions (see Photos 1 and 2). Such events are not modeled well using simple fire or jet fire models, especially for large diameter pipelines.

The release of gas from a rupture i s not a balloon burst, quick loss of pressure, or quick dissipation of a gas cloud. Rather, the gas continues to vent at high speeds even during the duration of the "blowdown time." Phase and pressure changes at any particular location upstream or downstre am of the rupture are governed by the thermodynamics of transient compressible fluid flow. The pressure changes from rupture may not show up for quite some time along pipelines, as such pressure loss indications are influenced by many factors that make rel iable pressure loss determination difficult during these highly transient events.

Blowdown venting can take many hours, especially if valve closure is delayed or if valve spacing is too great, increasing the volume and tonnage of compressible gas released and associated radiated heat generated.[45] The gas released calculations for gas transmission pipeline ruptures involve very complex

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[44] Hughes Report to PG&E Co., "Fire Hazard Area Evaluation, Radius of Influence for Jet Fires," Rev 3, March 24, 2011, p. 7.

[45] NTSB Report, Accident Report NTSB/PAR-95/01, "Pipeline Accident Report, Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire Edison, New Jersey March 23, 1994," adopted January 18, 1995. It involved a 36-inch pipeline whose fire raged for 2 ½ hours from over 7,000 tons of gas released.

engineering transient calculations along the pipeline, and such efforts are not represented in PG&E's testimony.

Photo 3 is a picture of the aftermath of the San Bruno crater and thrown pipe, as well as the actual impacted area showing the classic fingerprints associated with gas transmission pipeline rupture. A multi-ton section of the ejected thrown pipe (circled) is in the street toward the bottom of the photo. Accufacts has characterized the San Bruno release as a typical "low pressure" gas transmission pipeline rupture of a "large diameter" 30-inch 400 psig MAOP pipeline, that released over 1,150 tons of gas in the approximately 95 minutes it took to close manual mainline valves, each approximately slightly less than one mile from the rupture, and finally isolate the rupture site.[46, 47] The unusually long time it took to close nearby manual valves significantly contributed to the severity of this event, and serves as the foundation of today's testimony on this matter. TURN concurs with a NTSB probable cause finding: "Contributing to the severity of the accident were the lack of either automatic shutoff valves or remote control valves on the line and PG&E's flawed emergency response procedures and delay in isolating the rupture to stop the flow of gas."[48] Serious delays in getting to and closing manual isolation valves have extended high heat fire releases for many gas transmission pipeline ruptures and contributed to loss of life or massive property damage (see Photos 1, 2, 3, & 4).

3.2.2. PG&E's Testimony seriously understates isolation blowdown times.[49]

Testimony made by PG&E or its experts "that in the event of a rupture, pressure in the pipe will dissipate in minutes following valve closure" are misleading.[50]

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[46] NTSB Report, Accident Report NTSB/PAR-11/01, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010," adopted August 30, 2011, pp. 12 - 17.

[47] *Ibid., page x.*

[48] *Ibid., page xii.*

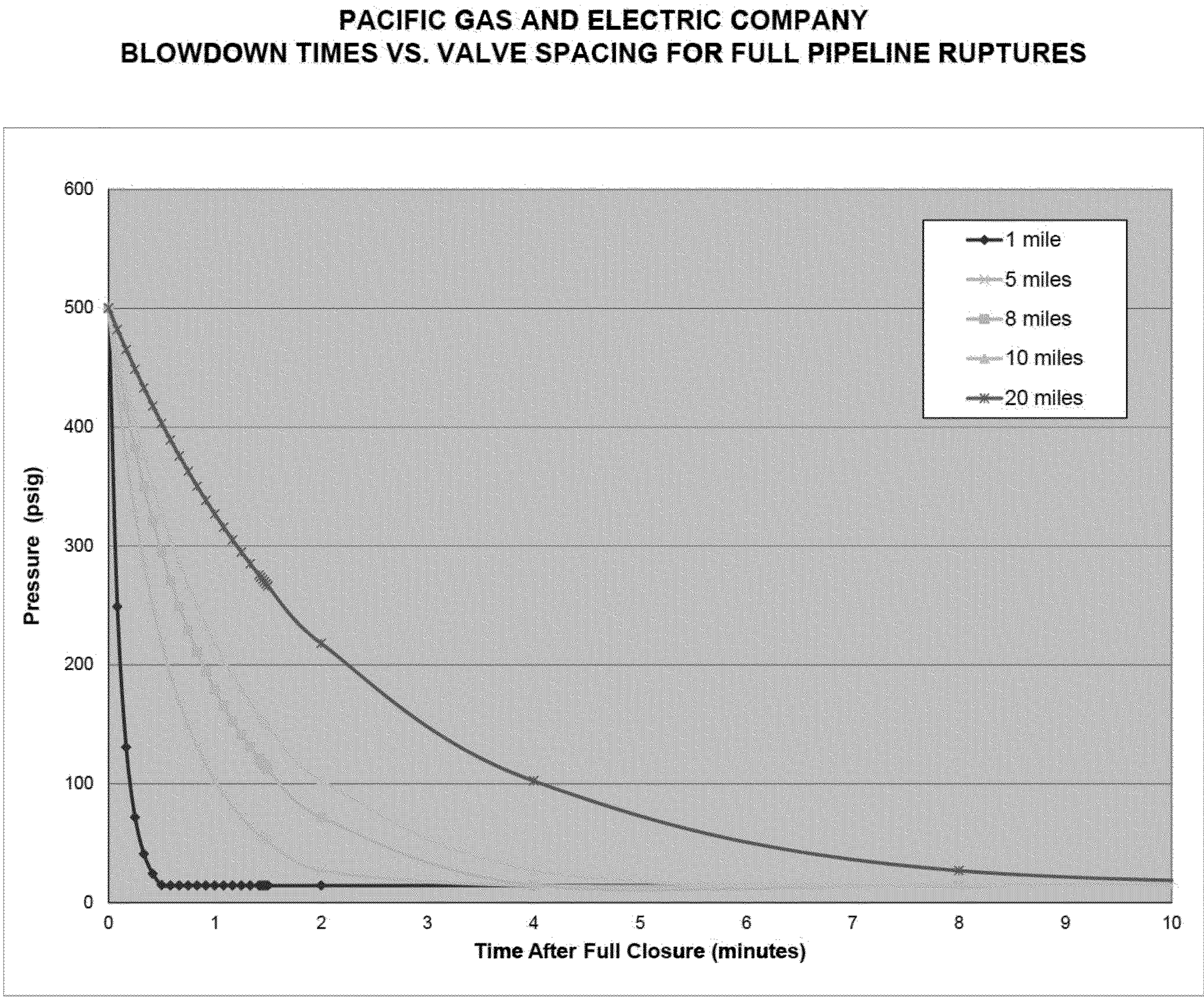
[49] PG&E Testimony, "Pacific Gas and Electric Company Blowdown Times vs. Valve Spacing for Full Pipeline Ruptures," Figure 4-7, page 4-23.

[50] PG&E Testimony, page 4-2.

Figure 5 reproduces Figure 4-7 from PG&E'S Testimony. This figure is incomplete, as it is missing critical information, such as pipe diameter, and seriously understates the isolation blowdown release times for gas transmission pipelines following rupture. The figure attempts to identify blowdown times but fails to accurately portray such times for gas transmission pipeline ruptures. PG&E apparently developed this figure for one particular pipeline diameter - a 12-inch pipe - and the calculation method used by PG&E's experts is unsuitable for long transmission pipelines.[51] The approach used by PG&E to estimate blowdown times for gas transmission pipelines ruptures to develop PG&E's Figure 4-7 is very inappropriate and should not be utilized for valve decisions on long gas transmission pipelines as pipe length, diameter, and friction factor play a substantial role in estimating rupture release impacts with time.

[51] PG&E's Response to TURN Data request TURN_014-Q01.

Figure 5: Blowdown Time, reproduced from PG&E Figure 4-7



A plot of an actual measured blowdown (pipeline pressure versus time) associated with an 18 -inch gas transmission pipeline rupture involving ASVs spaced ten miles apart, was provided in the testimony of Sempra and is reproduced as Figure 6.[52] Sempra has indicated that the ruptured pipeline was 7.2 miles from the ASV and the pressure measurement point indicated in Figure 6.[53] The actual blowdown time measured from when the ASV closed (see arrow at 500 psig) to approximately 40 psig is about 14 minutes, considerably more time by a factor of 3.5 times than that suggested by PG&E's Figure 4-7 above.

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[52] This Figure is reproduced from the Sempra Testimony Figure V-3 – Camarillo CA, 18" pipeline rupture, July 2011, dated 8/26/11, page 72.

[53] Sempra response to TURN DR-01-Q1.

Figure 6: Actual rupture pressure vs time, 18-inch pipeline

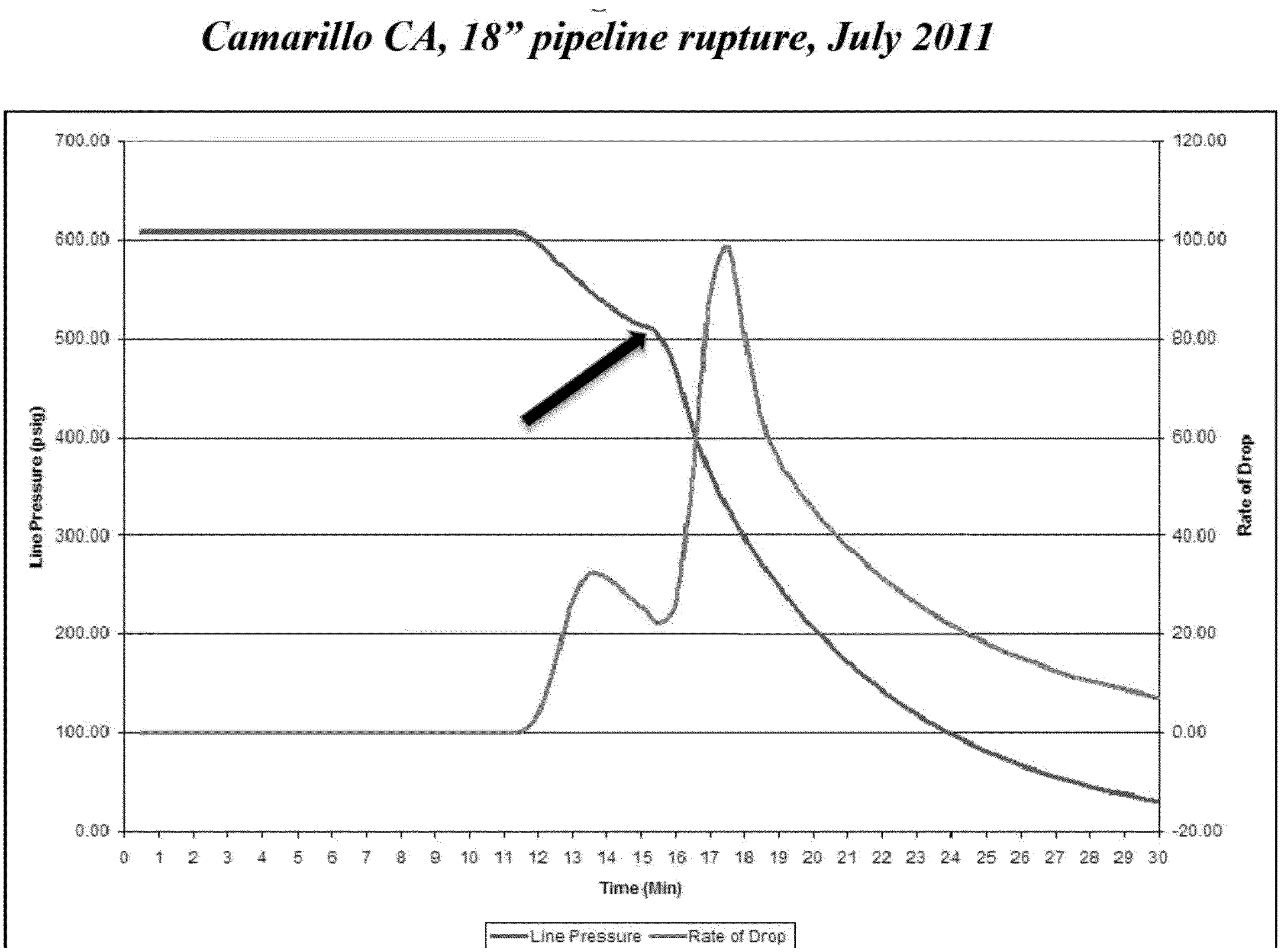

Figure 7 shows calculated "isolation blowdown" times, in minutes, to vent out the full bore end of a ruptured pipeline segment, <u>for various pipe diameters and pipeline lengths (in miles), once a pipeline segment has been isolated via a closed valve</u>, based on one industry study that more accurately captures the additional factors associated with transient complex calculations associated with long gas transmission pipeline rupture releases.[54] The study utilized an

[54] Gas Research Institute, GRI-95/0101, "Final Report – Remote and Automatic Main Line Valve Technology Assessment," July 1995.

initial pipeline pressure of 1000 psig, a common pressure for high-pressure gas transmission systems. Higher pressure will increase blowdown times mainly because of the greater gas inventory. The vertical dashed lines are the maximum valve spacing shown for reference for each Class Location as required by federal pipeline safety regulations (see

Table 6). Pipeline ruptures seldom occur in the middle span between two valves, so one pipe segment will usually vent longer than the other segment during a rupture.

Figure 7- Isolation Blowdown Time for Gas Transmission Pipeline Ruptures as a Function of Valve Distance from Rupture and Pipe Diameter

- Initial Pressure 1000 psig

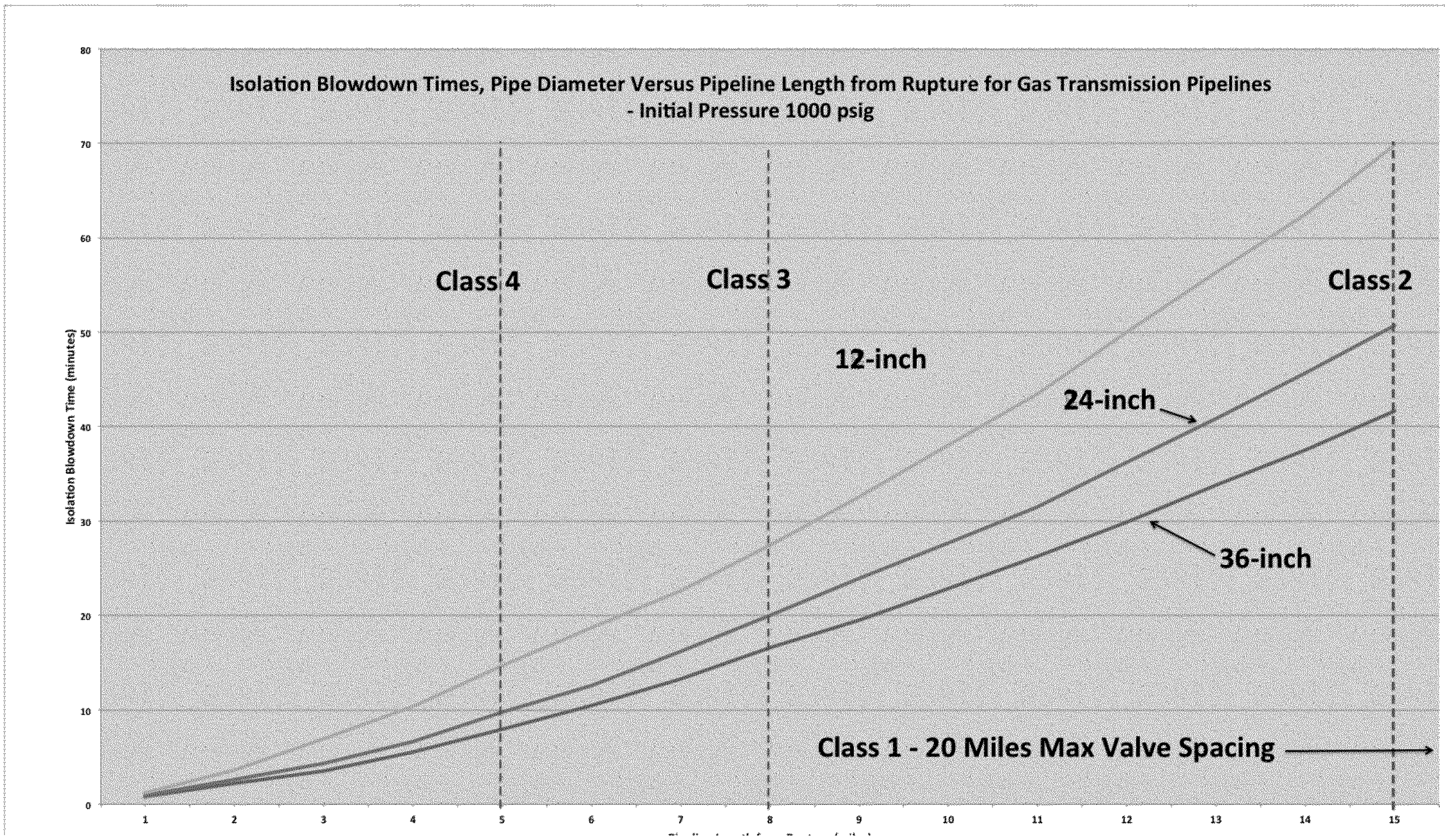

Table 6– Class Location and Federally Required Maximum Valve Spacing[55]

Class Location	**Maximum Valve Spacing**
Class 1	20 miles
Class 2	15 Miles
Class 3	8 miles
Class 4	5 miles

[55] 49CFR§192.179 – Transmission line valves. The same federal regulation allows PHMSA to permit alternate maximum spacing via the clause "unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:"

For long gas transmission pipelines, the time to vent or depressure during a gas pipeline rupture will be largely driven, once isolation valves are closed, by the pipe diameter, the friction factor of the long pipe, the distance from the valve, the initial pressure, and the laws of thermo and fluid mechanics for transient compressible flow which, among other things, sets the velocity of gas venting out of the bore at the speed of sound in the natural gas (which is much greater than the speed of sound in air). As Figure 7 indicates, isolation blowdown times increase substantially as the pipeline diameter gets smaller, or the valve spacing increases. For the same initial pressure and pipe diameter: doubling the valve spacing more than doubles the blowdown time, especially for smaller diameter pipelines. For example, the blowdown time for venting a 24-inch pipeline increases from approximately 20 minutes to over 50 minutes as valve spacing increases from 8 to 15 miles. As clearly evident in many gas transmission pipeline ruptures, such as the San Bruno tragedy, the time to identify a rupture, recognize and actually close isolation valves (especially large manual valves) crossing a rupture, can seriously increase venting by many times the isolation blowdown times shown in Figure 7, and increase the severity of the event.

Figure 7 contradicts PG&E's testimony that "A full line break with eight mile spacing with a pipeline starting pressure of 1000 psig is estimated to blowdown in five minutes."[56] Figure 7 indicates blowdown times significantly greater than five minutes, regardless of the pipe diameter. PG&E needs to explain this serious discrepancy, and provide an appropriate engineering analysis representing transient compressible flow in transmission pipelines that can be independently publically reviewed and confirmed.

Figure 7 also indicates that for an 18-inch pipeline with a 7.2 valve spacing (see Figure 6), blowdown times for calculated vs actually measured time are comparable correcting for the higher initial pressure of 1000 vs 500 psig.

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[56] PG&E Testimony, page 4-22.

Figure 6 and Figure 7 indicate that valve spacing plays a much greater role in isolation blowdown times than indicated by PG&E's testimony. Isolation blowdown times clearly impact decisions related to valve spacing and valve automation.

3.2.3. A Valve Automation Program should cut off the fuel supplying high heat releases from ruptures as quickly as possible.

The preceding discussion primarily concerned the isolation blowdown time. Isolation blowdown times are important for determining how soon first responders might be able to safely enter an affected area after valves are closed. However, the greatest heat generated from gas transmission pi peline ruptures usually occurs during the time before isolation valves spanning a rupture are actually closed. For large diameter pipelines these actual impact zones can be quite large. Photos 1, 2, and 4 are just three examples of pipeline flames associated with large delay times to close valves. An important objective following rupture is to quickly close prudently spaced isolation valves spanning a rupture.

Figure 8 is a typical graph of survivability from the effects of th ermal flux or heat radiation.[57, 58] To gain a perspective, fireballs associated with gas cloud ignition/detonation from large diameter gas transmission pipeline ruptures are <u>many times greater</u> than the 11,800 BTU/ft ^{2}-Hr shown on the right side of the graph (see Photo 1). Initial ignition, very high heat release, and fireballs, decline to lower, but still fatal and highly destructive thermal fluxes, as the rupture releases reach a longer duration "more stable heat release" associated with various characteristics of a specific pipeline (see Photos 1, 2 and 4). These high blowtorch heat releases can easily vaporize aluminum and liquefy steel. Accufacts has observed that many industry representatives seriously understate the heat fluxes associated with pipeline ruptures, especially larger diameter

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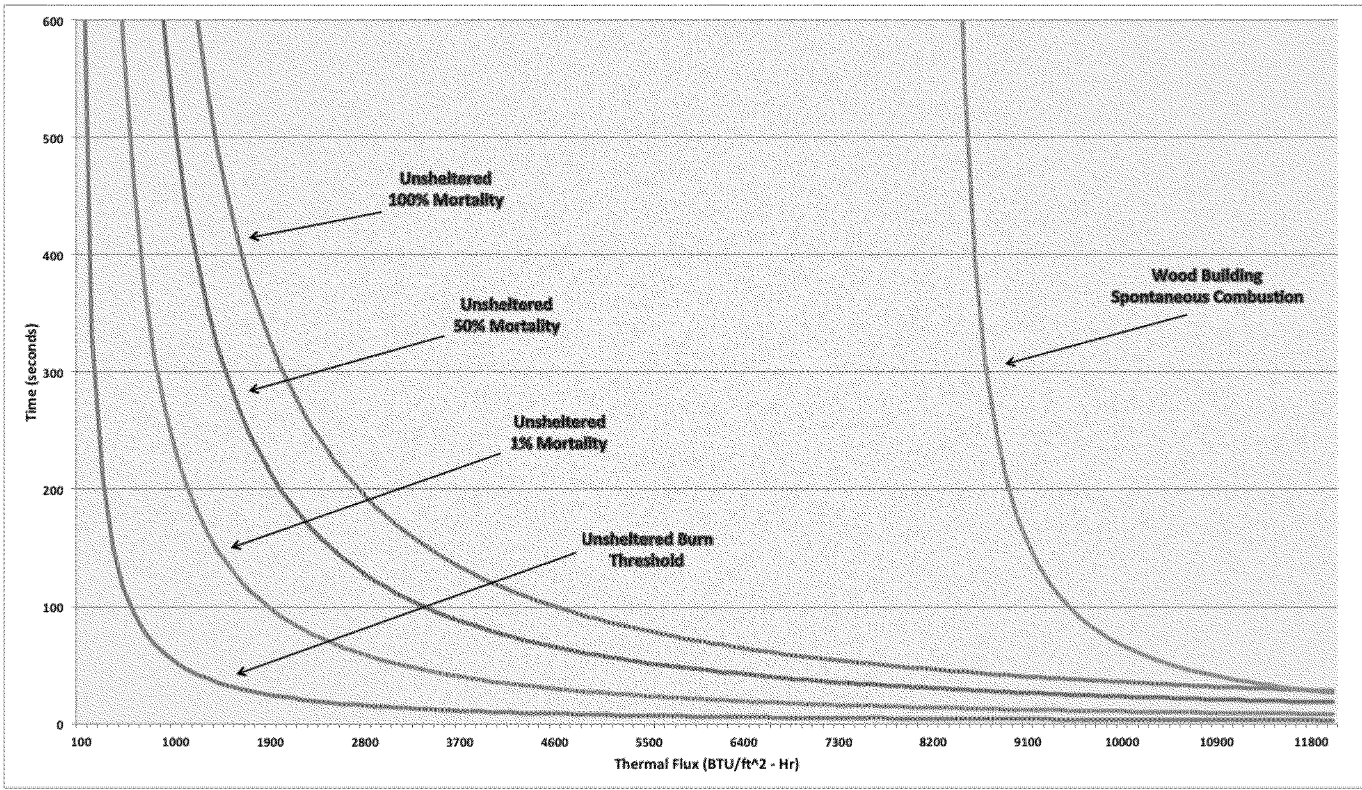
[57] Hymes, I., "The Physiological and Pathological Effects of Thermal Radiation," Systems Reliability Directorate, Report SRD, R275, Culcheth, Warrington, UK, dated 1983.

[58] Bilo, M. and Kinsman, P.R., "Thermal Radiation Criteria Used in Pipeline Risk Assessment," Pipes & Pipelines International, November-December, pp.17-25, 1997.

Figure 8– Thermal Flux vs Unsheltered Individuals or Building Survivability for Gas Pipeline Ruptures



pipeline releases, which are capable of releasing many tons per second of ignited gas at 900+ MPH.

The key factor to consider is the thermal flux or heat radiation associated with ruptures. It is the very high heat r elease associated with long duration large diameter gas transmission pipelines that can generate the greatest causalities (see Photo 1). In these massive gas releases, if isolation valves are not closed quickly, the heat fluxes will be well above "fatal" and "wood building spontaneous ignition" time periods, or thermal dosages, and will extend and expand the actual impact zone (see Photo 3, the San Bruno actual impacted area). The goal is to stay well to the left of each of the curves shown in Figure 8 by decreasing the high heat fluxes associated with long duration burns as quickly as possible, to increase the chance of survival. Survival is not assured when heat flux is kept high from delays in cutting off the fuel, and receptor s are close to the ruptured pipeline, especially unsheltered.

It is these sustained, longer duration, high heat releases that increase property damage and casualties, and frustrate first responders who can't get into the affected "hot" zone. Fire depar tments cannot enter such zones until the flames and gas rate of release has been substantially reduced from the high rate of gas and high heat flux phase of the release. The purpose of automated valves, especially on large diameter gas transmission pipelines, should be to substantially reduce the duration of high heat flux where mortality and structure failure are very high. Photo 4 illustrates the frustration exhibited by first responders for a large diameter 36 -inch gas transmission pipeline rupture in which manual valves were not successfully closed for 2 ½ hours. The fire truck shown is not as close as the perspective in the photo might lead one to believe. Even at the standoff distance the fire truck in Photo 4 sustained heat damage, and responders were prevented from entering the area for many hours.

Fortunately, while blowdown times increase with smaller pipe diameter, the high heat flux impact zone for rupture is substantially reduced as pipe diameter decreases, especially for pipelines much smaller than 24-inch diameter (see Figure 7), as the mass release (tons/sec) are substantially reduced for the smaller diameter pipelines, even at higher pressures. For gas transmission pipelines, pipe diameters come in discrete stan dard sizes (e.g., 42, 36, 34, 32, 30, 26, 24, 20, 22, 20, 18, 16, 12 inch, etc.,) with varying wall thickness.

3.2.4. The PIR Calculation does not adequately define the actual impact zone of a high heat release

PIR calculations cited in federal regulation do no t define the actual impact zone, especially for larger diameter pipelines. As a point of reference, the San Bruno pipeline rupture was the failure of a 30 -inch diameter gas transmission pipeline in a Class 3 Location at a pressure of approximately 386 psi g, a pressure failure below an unusually low MAOP of 400 psig. San Bruno's calculated PIR value is 409 feet which is considerably smaller than the building destruction actually observed of 750 plus feet indicated by the NTSB in their investigative report (see

Photo 3).[59] The PIR correlation referenced in federal regulation is not a pipeline siting tool and should not be utilized to define actual impact zones, especially for long duration large diameter pipeline ruptures.

The PIR empirical model correlat ion, also referenced as the C -Fer model, has been repeatedly demonstrated in numerous gas pipeline ruptures over the last several years to seriously understate the actual impact zone, especially for larger diameter pipelines.[60] In fact C -fer Technologies i n a letter to PG&E describing their modeling approach in determining the PIR relationship indicated that "While the rate of release rate decay during the initial stage of the fire (e.g. within the first 10 to 15 minutes) will be relatively insensitive to t hose boundary condition assumptions, the rate of decay in later stages will be progressively influenced by the distance from the break point to the upstream and downstream stations and by the pressure and flow conditions at those locations. Release rate decay projections beyond 15 minutes should therefore be interpreted with caution."[61] PG&E in their testimony related to valve automation stated that "A key fact worth noting is that 15 minutes after the rupture, the heat intensity has significantly decrease d due to the reduction in natural gas mass release rate at the rupture."[62] Such citations fail to mention that the heat flux after 15 minutes, especially with large diameter pipelines will still be especially high because the initial rates of gas released in the early moments of a pipeline rupture are significantly higher than the flow within the pipeline before rupture. For large

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[59] National Transportation Safety Board ("NTSB"), "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010," Accident Report NTSB/PAR-11/01, adopted August 30, 2011, "Figure 11 - Picture showing area of damage from blast and fire," page 19.

[60] Mark J. Stephens, C-FER Technologies, topical report prepared for Gas Research Institute, "A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines," GRI-00/0189, October, 2000.

[61] Response to TURN data TURN_015-Q01Atch02, C-Fer Technologies letter to PG&E, "Adaptation of C-FER PIR Formula to Alternative Hazard Assessments," dated March 10, 2011.

[62] PG&E IP testimony, p. 4-17.

diameter gas transmission pipeline ruptures, even after 15 minutes, "reduced heat intensity" can be fatal and highly destructive (See Photos 1, 2 & 4).

The PIR values identified in PG&E's decision trees make little sense, especially with respect to the use of "low" PIR cutoff values (PIRs of 100, 150 and 200).[63] These low PIRs are reflective of very small diameter gas transmission pipelines, on the order of 12 to 16-inch, which will have very long duration isolation blowdown times. Additionally, PG&E statements trying to justify these low PIR values also reflect a very poor understanding of gas rupture release dynamics and proper emergency response for very high heat flux rupture events. For example, firefighters should never direct water streams into an ignited natural gas rupture roaring from a gas transmission pipeline rupture at 900+ mph as water is ineffective in such conditions. Well meaning first responder attempts to cool structures in close proximity to the rupture blowtorches or near very large gas clouds (See Photo 1, 2 & 4) can prove fatal. A first responder experienced with such very high heat intensities will understand that water will not protect nearby structures from such massively high heat intensity, or very turbulent gas clouds (see Photos 1, 2 and 3). The primary objective of emergency response to gas transmission pipeline ruptures is initially controlled by the pipeline operator and operators should quickly assure prudently spaced valves spanning the rupture are swiftly closed. Rapid closure of valves will knock down the higher rate heat release phase of the rupture as quickly as possible to allow first responders to safely enter the actual impact zone as soon as possible. As Figure 7 demonstrates, rapidly closing properly placed valves with spacing of no greater then 8 miles will substantially reduce the blowdown time on affected segments in the event of rupture.

[63] PG&E Testimony, page 4-17.

3.3. PG&E's decision tree for Phase 1 should should be modified to focus on pipes over 24-inches and to utilize only ASVs

PG&E's decision trees, which are reproduced as Figure 9 and Figure 10 below, are inadequate.[64] PG&E'S use of the PIR in their valve decision trees does not adequately address the goal of quickly reducing high heat flux times and actual impact zones.

[64] PG&E Testimony, "Figure 4-3 PG&E Decision Tree – Population Density," and "Figure 4-4 PG&E Decision Tree – Earthquake Fault Crossing," pages 4-11 and 4-12.

Figure 9: PG&E Valve Decision Tree

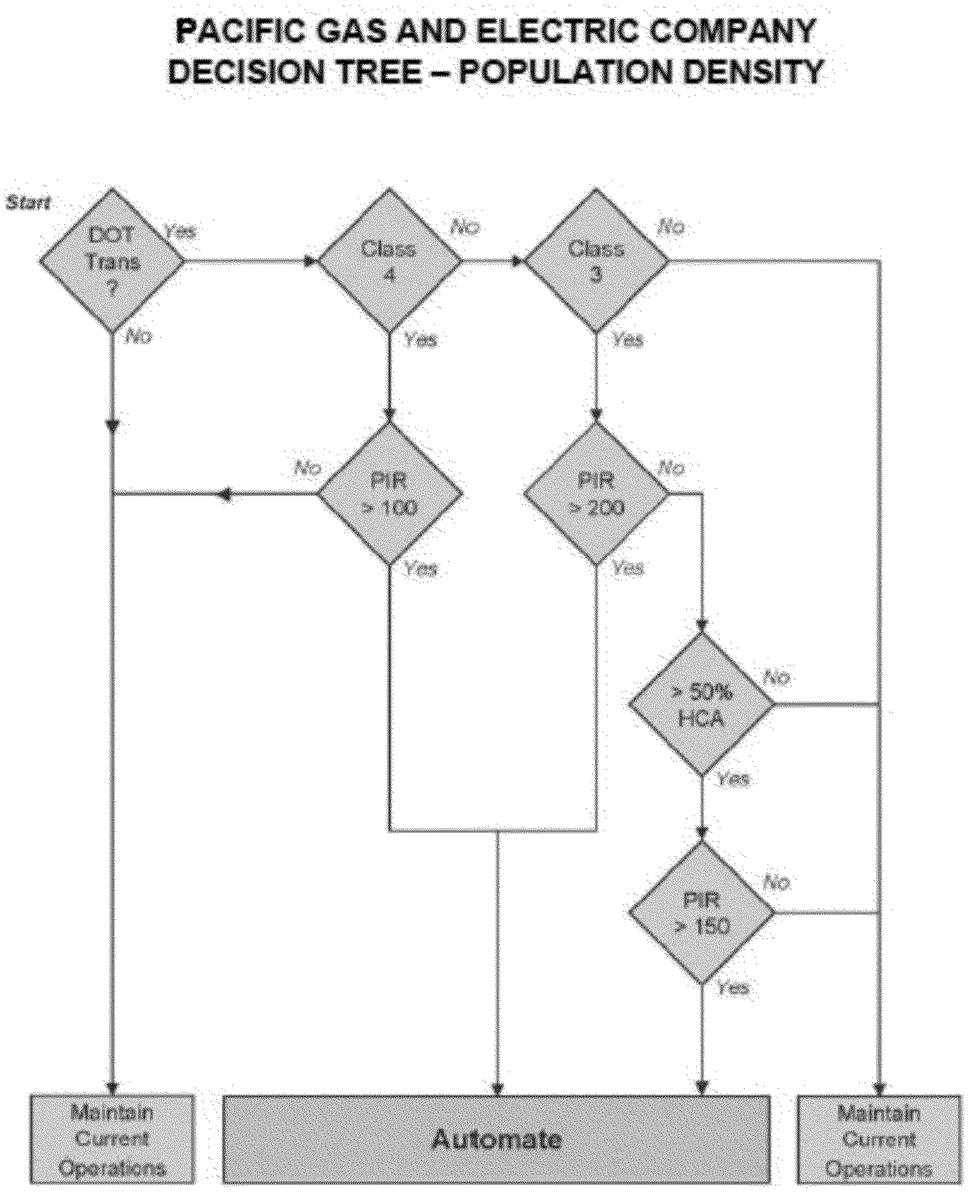

Figure 10: PG&E's Earthquake Fault Valve Decision Tree

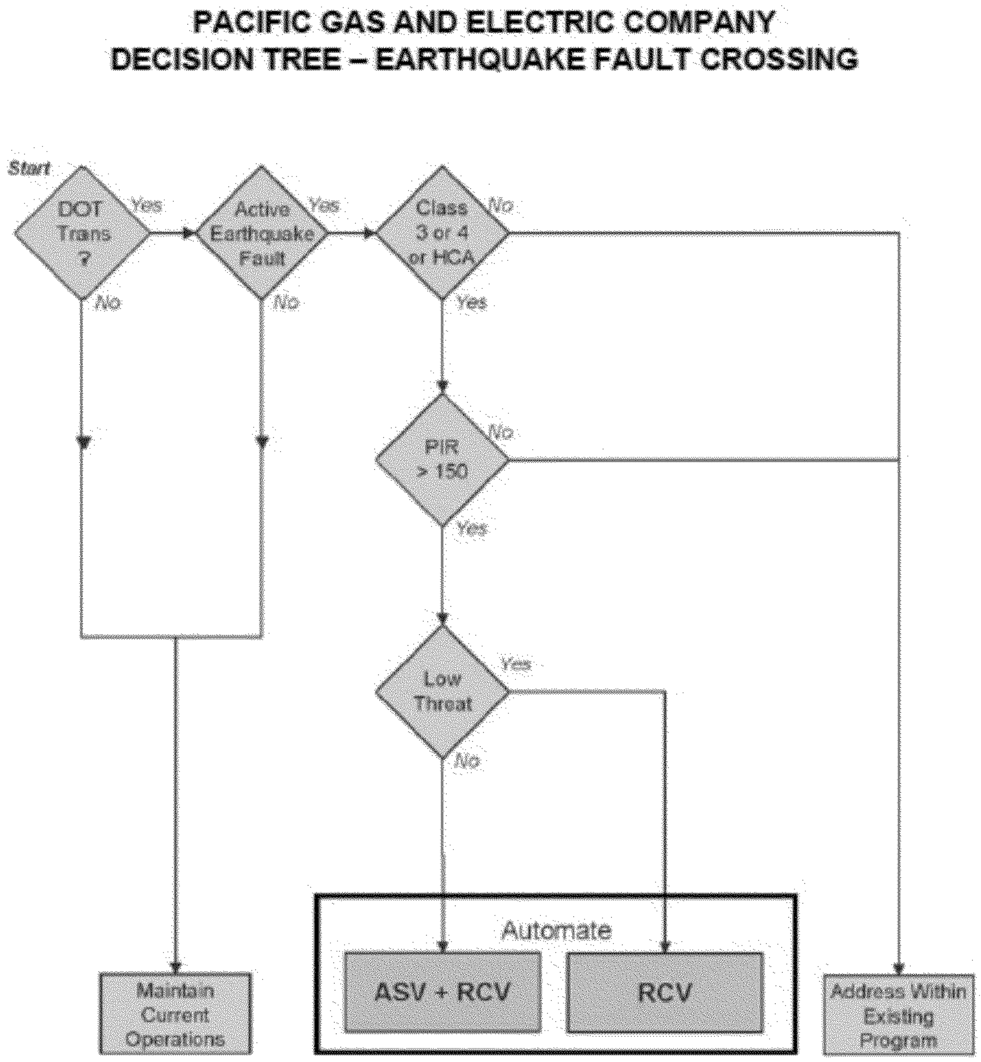

Figure 11 – Accufacts' Valve Decision Tree

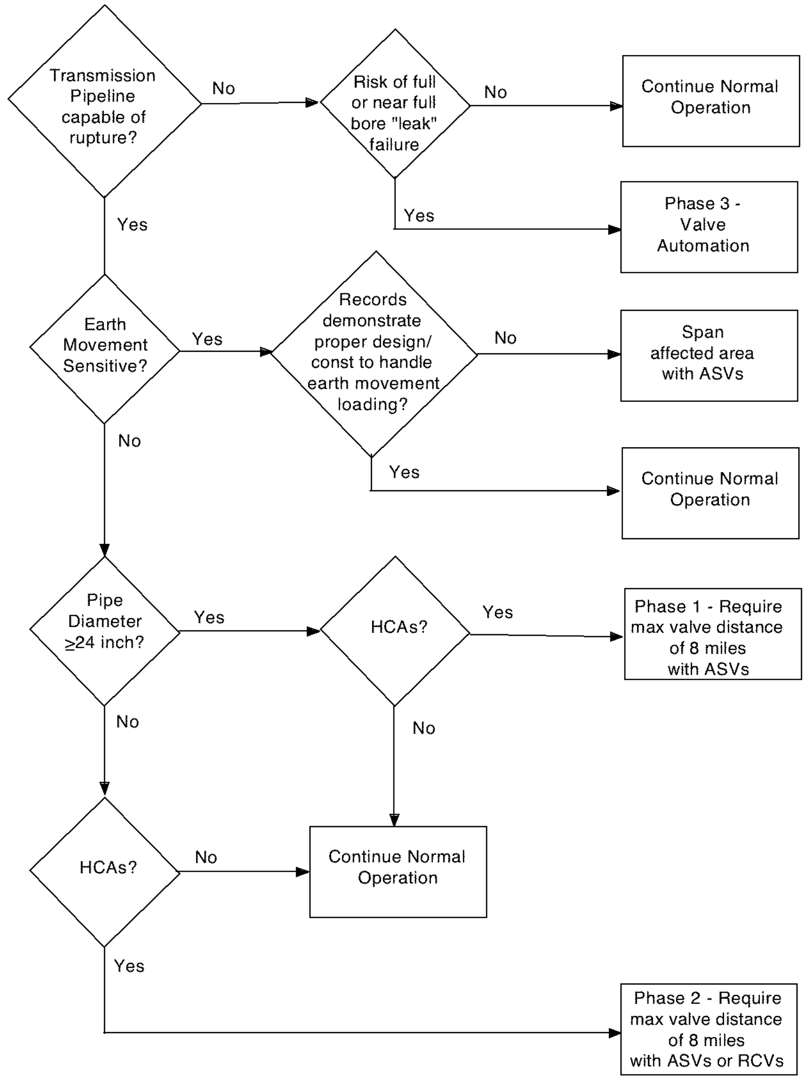

Figure 11 is a more appropriate valve decision tree that TURN recommends should be utilized to determine the prudent placement and automation of valves on gas transmission pipelines. Several important points related to Figure 11 need to be highlighted.

1. Phase 1 should install ASVs spaced at a maximum of eight miles on all pipelines equal to or greater than 24 inches spanning HCAs.
2. Phase 2 should install ASVs or RCVS at a maximum spacing of eight miles on all pipelines less than 24 inches spanning HCAs.
3. Phase 3 should install valve automation on remaining low pressure transmission pipelines that are at risk of a full bore "leak failure" such as poor girth welds.

The timing of phase 2 or phase 3 should be determined after phase 1 has been well underway.

Table 7 represent the PG&E pipeline miles for HCAs and nonHCAs by pipe diameter and Class Location.[65] Table 7 illustrates that almost 60% of the mileage in PG&E's gas transmission system is less than 24 inch.

Table 7: PG&E Pipeline miles by Pipe Diameter and Class Location

	Class 1 and 2 Pipe Miles	Pipe Miles %	Class 3 and 4 Pipe Miles	Pipe Miles %	Total Pipe Miles	Total Pipe Miles %
Pipe OD => 24 in	**1,971.5**	**48.2%**	**465.3**	**27.0%**	**2,436.9**	**41.9%**
HCA	59.5	3.0%	391.0	84.0%	450.5	18.5%
Non-HCA	1,912.0	97.0%	74.4	16.0%	1,986.4	81.5%
Pipe OD < 24 in	**2,117.8**	**51.8%**	**1,259.8**	**73.0%**	**3,377.6**	**58.1%**
HCA	20.9	1.0%	555.7	44.1%	576.7	17.1%
Non-HCA	2,096.9	99.0%	704.1	55.9%	2,801.0	82.9%
Grand Total	**4,089.3**	**100.0%**	**1,725.1**	**100.0%**	**5,814.5**	**100.0%**

In addition Figure 12 provides a more detailed analysis of the PG&E proposed 194 valves in their proposed Phase 1. Figure 12 indicates that 61, or approximately one-third of PG&E's proposed valves, would be on lines less than 24 inch in diameter.[66]

[65] Developed from response to TURN data request TURN_008-Q01Atch01.

[66] TURN analysis from PG&E's Response to data request TURN_015(Q2).

Figure 12– PG&E's Proposed Phase 1 Valves by Pipe Diameter and Pipe Miles in Class 3 and 4

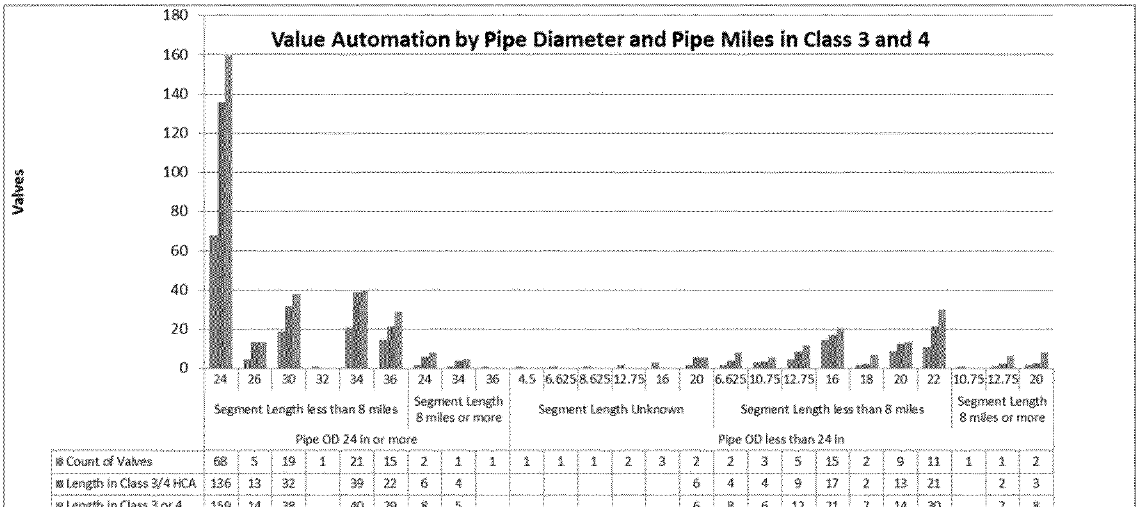

Figure 12 also indicates that four of the Phase 1 proposed valves on the larger diameter pipelines have valve spacing greater than 8 miles. TURN believes a closer study of the specific location of these four valves is warranted , though the isolation blowdown may not change significantly. A review of Figure 7 indicates that isolation blowdown times for smaller diameter lines will prevent even ASVs from meeting the 30 minute responder goal for valve spacing of eight miles. Fortunately, smaller diameter pipelines produce much smaller potential impact zones following a rupture than their larger diameter counterparts during longer duration burns.

PG&E's decision trees also fail to address HCAs in Class 1 and 2 locations, where survivability can be especially low in the event of a gas pipeline rupture because of the much greater blowdown times associated with far greater valve spacing. Both of PG&E's decision trees appear to be biased toward utilizing existing valve locations to minimize new valve installation. In Class 1 and Class 2 locations spanning HCAs, TURN recommends a maximum valve spacing of no greater than eight miles to reduce the much greater blowdown, and associated high heat burn times in these sensitive HCAs defined as "identified sites" in federal regulations. Identified sites are those gathering locations that may contain numbers of unsheltered individuals or difficult to evacuate sites where survivability is at its lowest in the event of a rupture.

TURN further recommends that all segments in Class 1 and 2 HCA locations equal to or greater than 24 inches in diameter be automated using ASVs. PG&E

has indicated that eighty miles of Class 1 and 2 transmission pipeline are designated as HCAs, and approximately 60 miles of these HCA segments are large diameter pipelines (see Table 7).[67] PG&E's needs to identify the number of valves that would be required to be installed and/or automated to cover HCAs in Class 1 and Class 2, by pipe diameter.

The "earth movement sensitive" decision point relates to gas transmission sites subject to major earth movement such as serious liquefaction or earthquake faults. It shoul d be noted that the risk of these earth movement threats can be mitigated in many cases by proper engineering design and construction that will absorb such movement abnormal loading threats without failure. The science has advanced considerably in the last several decades on the engineering of earth movement threats and abnormal loading on pipelines, especially for new pipelines. Records proving proper design/construction for such at -risk pipeline segments should be readily available for review for the life of the pipeline.

For smaller diameter pipelines, less than 24-inch, TURN is recommending maximum valve spacing of eight miles, either ASV or RCV automation, as the heat fluxes associated with these smaller diameter pipelines is considerably less than that of the larger diameter pipelines. On smaller diameter lines, burn times will be longer, but the actual impact area hot zone considerably smaller.

3.4. Fears raised concerning ASV accidental closures are exaggerated and unwarranted if prudently engineered.

Several comments are made in PG&E's testimony about the dangers of ASVs closing when not needed (i.e., false closure), exposing customers to a loss in service. TURN believes the risk associated with ASV false closure is overblown. While the logic associ ated with detection to activate ASVs upon indication of a rupture can be complex (one cannot rely on pressure loss, because of the compressibility pressure affects associated with long gas transmission pipelines), TURN believes an ASV approach can be designed and incorporated that

[67] Response to DR TURN_008-Q01Atch01. A very rough approximation of additional valves (based purely on pipeline length would be about 16.

prevents ASVs from accidental closure. A similar design approach may also be warranted for RCVs, as Accufacts' experience has uncovered poorly designed RCVs that can also close without operator initiation. A proper process safety management approach in ASV or RCV design/construction (via a well documented HAZOP analysis) should eliminate unwanted closure on those valves identified for automation.[68] Such designs, for example, should never rely on a single component/signal to initiate closure.

Throughout PG&E's valve testimony, references are made to the results of an industry survey.[69] Accufacts has reviewed this report and its related "brief questionnaire" in detail, and places little weight in its observations, findings, or in an industry perspective as it relates to the question of valve automation on gas transmission systems. For example, the survey fails among other things to ask a key question - How are RCVs and ACVs on a pipeline operator's system designed and installed? An answer to such a question would truly assist parties in an independent analysis to prudently automated valve selection and installation.

The NTSB independent investigation San Bruno report summarized the history of this issue and the history of industry delay in promoting the use of automated valves: "The NTSB has long been concerned about the lack of standards for rapid shutdown and the lack of requirements for ASVs or RCVs in HCAs. As far back as 1971, the NTSB recommended, in Safety Recommendation P -71-1, the development of standards for rapid shutdown of failed natural gas pipelines. In 1995, the NTSB recommended, in Safety Recommendation P -95-1, that RSPA expedite requirements for installing automatic- or remote-operated mainline

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[68] HAZOP stands for Hazard and Operability Analysis, a methodical structured and systematic technique utilizing experienced engineers and operators to analyze proposed designs, and engineer such failure out of the design. Such analysis must be well documented to demonstrate thoroughness, permit auditing, and to avoid tampering.

[69] ENengineering Report prepared for PG&E, "Industry Survey of Operation Natural Gas Pipeline Operators on Automatic Valves," dated April 4, 2011.

valves on high-pressure pipelines in urban and environmentally sensitive areas to provide for rapid shutdown of failed pipeline segments. The NTSB classified Safety Recommendation P-95-1 "Closed—Acceptable Action," believing that the RSPA 2004 integrity management rulemaking (requiring that each gas transmission operator determine whether installing ASVs or RCVs would be an efficient means of adding protection to an HCA) would lead to a more widespread use of ASVs and RCVs. However, it did not."[70]

PG&E's testimony that RCVs can be installed and then later easily converted to ASVs is particularly troubling. Accufacts' experience indicates that ASV design approaches are significantly different than RCVs design, and such a simplistic approach clearly signals that a "simple converted RCV" to ASV will in all probability fail close, or more importantly, fail to automatically close when actually needed during a rupture because of very poor hazard analysis and design.

Instrument engineers, and for that matter many pipeline engineers, are often poorly equipped or inexperienced to perform prudent process safety management HAZOP analysis that should be utilized for careful RCV or ASV design and there is no regulatory requirement to perform such an analysis. Accufacts concurs with one important point suggested by PG&E's line of testimony. If a company cannot assure a careful safety process design to prevent accidental closure of mainline valves, the company should not be designing or installing such equipment without more competent and experienced guidance.

PG&E should reconfigure its valve automation program to capture the highly transient factors and high heat flux phase of gas transmission ruptures. I have proposed that large diameter transmission pipelines ($\geq$ 24-inch) in HCAs be

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[70] NTSB Report, Accident Report NTSB/PAR-11/01, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010," adopted August 30, 2011, p. 103.

automated during the Phase 1 effort with maximum valve spacing spanning such areas of no greater than eight miles (Class 3 requirement) with prudently designed ASVs, because of their more rapid response and closure time over RCVs following a rupture. Remaining smaller diameter pipelines spanning HCAs should be automated with either RCVs or ACVs in a later Phase 2 effort. A Phase 3 effort (see Figure 11) has been proposed for transmission pipeline segments that can't rupture, but contain the risk of possible near or full bore failure "leak" threats (such as failed girth welds), that can release significant volumes of gas in the event of failure.

3.5. The ability of SCADA to quickly identify gas transmission ruptures is overstated.

Identification of a gas pipeline rupture via SCADA is much more difficult than one may think, especially if there are compressors or other pipeline tie -ins that add to the complexity that can seriously delay shutoff response to these events, increasing gas release on a particular gas transmission pipeline segment. Many pipeline companies require confirmed reliable field verification of a gas rupture before initiating emergency response and shutdown isolation on some of their systems.[71] Remote identification of a gas pipeline rupture via SCADA is complicated by factors such as: 1) the location of the pressure measurement on the pipeline in relation to the rupture site, 2) the complex transient dynamics associated with compressible gas flow that delays pressure loss indications down a long pipeline, even for rupture (see Figure 7 which follows pressure decay <u>once isolation valves have been closed</u>), 3) the complicated pressure cycling dynamics associated with most gas transmission operations that make pressure loss evaluation by a control room operator for a rupture very difficult to distinguish from normal operations, and 4) the potential for frequent alarms to overload and set up the control room SCADA operator to ignore real alarms as false. All these factors serve to severely complicate and delay decisions by the control room operator to initiate proper valve closure during a rupture event, whether for manual or RCVs.

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[71] AGA White Paper, "Automatic Shut-off Valves (ASV) And Remote Control Valves (RCV) On Natural Gas Transmission Pipelines," March 25, 2011, p. 3.

The tools identified in PG&E's testimony to allow for early detection of a gas transmission pipeline rupture via a SCADA operator will prove to be highly ineffective in helping to quickly and effectively identify a gas transmission pipeline rupture, especially on such a complex system as PG&Es.[72] Over the last decade, Accufacts has been involved in numerous efforts to effectively and efficiently improve control room management operations via advancements in federal pipeline safety regulations in this area, and these many efforts are a matter of public record.[73]

3.6. Summary of TURN Recommendations

Turn advises that a Class 3 maximum spacing between valves of eight miles should be imposed on all pipelines crossing HCAs, regardless of the actual class location and that all such valves be automated. This will, in all probability, mean that new valves will need to be installed in Class 1 and 2 locations spanning HCAs. But a smaller number of valves overall will be required due to the elimination of pipelines below 24-inch from Phase 1. PIR is a very poor predictor of the actual impact zo ne associated with gas pipeline ruptures, especially for sustained burn large diameter pipelines, and PIR should not be utilized to establish valving decisions. Accufacts advises that pipe diameter is a better predictor of actual impact zone. PG&E transm ission pipelines equal to or greater than 24-inch diameter spanning HCAs should be given first priority in a Phase 1 valve effort and all such valves should be installed as ASVs given the much greater potential for massively high rate gas, high heat, relea ses and their ability to permit first responders to enter an affected area much earlier than RCVs. The remaining HCAs, containing less than 24-inch diameter pipelines, should be valved and automated, either via ASV or RCV, in a later phase 2 effort to complete coverage of the HCAs.

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[72] PG&E Testimony, page 4-6.

[73] 49CFR§192.631 Control room management.

TURN places little merit in arguments to avoid ASVs that reflect very little experience in process safety management design for such important "safeties." Such reasoning suggests little understanding or commitment to really im proving pipeline safety in dealing with a pipeline rupture.

4. Evaluation of the Pipeline Records Integration Program

4.1. Summary of PG&E's Proposal and TURN's Recommendations for Modifications

PG&E proposes to update its pipeline records program using two appro aches: 1) a Maximum Allowable Operating Pressure ("MAOP") Validation Project to reaffirm its gas transmission pipeline MAOPs, and 2) a Gas Transmission Asset Management ("GTAM") Project to shift its records system to another electronic database. PG&E expla ins that "The MAOP Validation project involves collecting and verifying the pipeline strength tests and pipeline features data necessary to validate and re -calculate the MAOP for PG&E's gas transmission pipelines and pipeline system components." [74] PG&E fur ther states the GTAM project "will substantially upgrade its gas transmission processes and record management infrastructure, allowing it to transition away from reliance on traditional paper records and to consolidate data into integrated, core data management systems."[75]

Table 8 summarizes the total PG&E projected costs (both capital and expenses). Given the many gaps and breakdowns in retaining safety critical information pertaining to PG&E's gas transmission system, TURN agrees that there is a strong need to improve records integration, retention, and accuracy within PG&E.

[74] From PG&E, Prepared Testimony, page 5-1.

[75] From PG&E, Prepared Testimony, page 5-1.

Table 8 - PG&E's Pipeline Records Integration Program Yearly Cost Forecast (millions $)[76]

	2011	2012	2013	2014	Total
Subcomponent Project					
MAOP Validation Project	55.2	82.2	24.9	-	162.3
GTAM Project	7.9	48.1	34.7	32.9	123.6
Total	**63.1**	**130.3**	**59.6**	**32.9**	**285.9**

PG&E is proposing that the MAOP Validation occur in three phases[77]:

- Phase 1 - A search for past strength test (mainly hydrotests) records for pipeline in HCAs.[78]
- Phase 2 – For HCA segments with no producible hydrotest records, which can fairly be characterized as a "best guess" MAOP determination/calculation.
- Phase 3 – For all remaining pipelines (nonHCAs) a MAOP determinatio n using the Phase 2 approach.

PG&E has represented that they have approximately 5,763 miles of transmission pipeline of which 1,027 miles are in HCAs.[79] Phase 2 and 3 would be used where proper strength test records cannot be found during ongoing record searches.

Accufacts recommends the following:

[76] From PG&E, Prepared Testimony Table 5-1, page 5-4, and Tables 5-4 and 5-5, page 5-27.

[77] PG&E uses the words "three parts" for MAOP, and "three phases" for GTAM. I use the terms interchangeably, keeping in mind that all of the MAOP validation project is scheduled for completion in Phase 1 of the PSEP.

[78] A strength test can be a pressure test using gas in some cases. In most cases, for various reasons, the strength test will be a special high-pressure test with water, which is called a hydrotest.

[79] From data provided in PG&E Prepared Testimony, Table 4-3, "Pacific Gas And Electric Company Pipe Miles by PIR, Class and HCA," p. 4-38.

- I strongly object to PG&E's proposed Phase 2 and 3 "conservative assumptions" approach to validating the MAOP under §192.619(a)(1). Attempts to fill-in missing important safety critical information establishing MAOP can be unique to a pipeline segment, especially older pipelines. Such important pipeline safety critical information should have been retained for the life of the pipelines. Using a process to try and replace or bridge such important missing data gaps for MAOP determination is not satisfactory or appropriate. For pipeline segments for which strength tests were required either by industry standard, state or federal regulations and for which PG&E cannot now produce hydrotest records, such pipelines should be hydrotested or replaced, and the costs for such action be borne by the shareholders of the company.
- I do not object to the substance of GTAM efforts provided all of the following conditions are met[80]:
  1) PG&E can truly demonstrate and realize major cost efficiency savings from such a "new" centralized electronic database system
  2) PG&E installs more than one level of effective system protection to assure that safety-critical information accurately represents the specific equipment in the field and is correctly input into electronic database systems (i.e., avoid entering false information or data entry errors),
  3) sufficient levels of security protection are incorporated to prevent tampering by employees or management, and
  4) the database is backed up in more than one location to avoid catastrophic failure that may cause the loss of such core business files.

The MAOP Validation process should be brought into compliance with NTSB recommendations for pipelines in in class 3 and 4 and HCAs that do not have an appropriately verified previous hydrotest validating MAOP. While not mentioned in the NTSB recommendations, the same requirements should be imposed on pipeline segments in non-HCAs, but at a lower priority.

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[80] I note that Mr. Long's testimony makes additional recommendations regarding cost recovery and cost responsibility for GTAM project costs.

The GTAM proposal should proceed after PG&E has demonstrated that the specific effort will meet the four conditions outlined previously. In addition, PG&E should define and outline what management audit steps will be incorporated into the organization to assure and demonstrate the GTAM is accurate and not subject to failure, given the previous reported history of failing to complete important records within this company.

4.2. The MAOP Validation Project

4.2.1. Phase 1 Will Result in Significant Changes to the Scope of Work of the PSEP

Phase (or "part") 1 of the MAOP project involves the continuing search for all strength test records, and the migrating of this information to PG&E's GIS database. PG&E is apparently not seeking ratepayer funding for this portion.[81] Obviously, this is work that PG&E must perform, and work that is apparently required because PG&E cannot readily access its strength test records.

I have two observations concerning this phase. The first is that PG&E should maintain quality control processes for input into the "interim electronic database" and for the migration to the GIS database.

More importantly, as I discussed in detail in Section 2.1 of my testimony, the MAOP validation is bound to result in significant *reductions* to the scope of work as PG&E locates hydrotest records not included in its version of the PSEP Database. While I could foresee some work additions due to the discovery of erroneous data entries, by far the impact will be to reduce work. Indeed, the MAOP validation process already decreased PG&E's expected 2011 hydrotesting by almost one-third, due to the discovery of strength test records for 44 miles of pipe.

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[81] PG&E Testimony, pages 5-8 to 5-9.

4.3. PG&E's Part 2 Proposal to Use "Conservative Assumptions" Should Not be Approved

4.3.1. PG&E's Proposal does not meet the NTSB Safety Recommendations and Places the System at Serious Risk

NTSB Urgent Safety Recommendations (P-10-6) to the CPUC and to PG&E (P-10-4) have been very clear concerning pipeline segments in HCAs.[82] If PG&E cannot provide the necessary traceable, verifiable and complete records to determine a valid MAOP, a special hydrotest, including a spike test, must be performed for those segments missing such critical records. TURN concurs with these NTSB Safety Recommendations.

Assuming data as proposed in PG&E's Phase 2 effort in an attempt to fill in missing safety critical information about what is actually in the field is a very poor risk management approach. There is certain data that must be verified via testing or assessment to confirm a pipeline's important features. This critical principle related to core data and record keeping is at the heart of the integrity management approach codified in federal pipeline safety regulation.[83] In fact, ASME B31.8S-2004 Section 4, incorporated into pipeline safety law by specific reference indicates, "When the operator lacks sufficient data or where data quality is below requirements, the operator shall follow the prescriptive-based process as shown in Nonmandatory Appendix A." In other words, lacking certain sufficient data the Nonmandatory Appendix A becomes mandatory and the obligations on the pipeline operator become fairly specific as to hydrotesting requirements, for example, for specific threats such as manufacturing threats.[84]

The NTSB did not specifically address whether hydrotests are required in pipeline segments not in class 3 & 4 or HCAs (PG&E's MAOP Validation Phase 3 proposal). TURN recommends that if traceable, verifiable and complete records

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[82] NTSB Report, Accident Report NTSB/PAR-11/01, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010," adopted August 30, 2011, pp. 132-133.

[83] 49CFR§192.917 and 49CFR§192.947.

[84] ASME B31.8S-2004, Sections 4 and Appendix A.

to determine a valid MAOP for remaining non -HCA segments cannot be found, the next step should be to hydrotest or replace such pipe in a later phase following the hydrotesting of class 3, 4 and HCAs, which should be given priority.

One of the most serious breakdowns in applying risk management techniques is to attempt to fill in missing impo rtant safety critical information by guessing. Even industry experts cannot extend or extrapolate data beyond its intended range. This is especially true for PG&E's pipelines where certain information critical to MAOP determination cannot be readily found. PG&E's MAOP Validation Phase 2 and 3 proposals are leaps of faith, attempting to bridge critical information gaps concerning MAOP that can have serious future liabilities to the company, the regulators, and the public. TURN does not advise such an approach for MAOP Validation, especially for older pipelines that can have imperfections susceptible to various interactive forces that can result in pipeline rupture. There are very good reasons why hydrotesting is imposed on new pipelines and many of these reasons carry over, especially to older pipeline systems.

4.3.2. To the extent that appropriate gas transmission pipeline strength test records cannot be produced to verify MAOP, a hydrotest or pipe replacement should be required

The MAOP Validation program Pha se 2 and 3 proposed by PG&E, basically constitutes conjecture as to what is actually in the field. Phase 2 and 3 are apparently to be utilized on most of PG&E's system, given information provided to date. Much information apparently is still missing in PG&E's records, especially related to strength testing and MAOP. TURN finds especially disturbing PG&E testimony that "In those instances where a complete record set is not available, PG&E will make conservative assumptions about certain components based o n the material specification in place at the time the material were procured, sound engineering analysis, and field testing of pipeline systems as appropriate. PG&E will then determine the type of field testing to employ on a case-by-case basis and will c onsult with Commission staff about the proposed field testing."[85] There appears to be a long case history demonstrating that PG&E cannot be relied upon to prudently deal with missing records, and even "conservative" assumptions can be absolutely wrong, especially if the inappropriate assessment methods, such as Direct Assessment, are selected in a poor gas transmission pipeline integrity management program.[86]

A hydrotest is a proof verification requirement that certifies that certain various critical as sumptions are indeed true, at the time of the strength test, and all proper hydrotests provide some level of pressure safety margin established at the time of the hydrotest. This important concept was codified in the CPUC's own Order 112 that went into ef fect in July of 1961. It is also worth mentioning that any new pipeline segment replaced will be required to also undergo a hydrotest strength test prior to operation, as required in federal pipeline safety regulations.

4.4. The GTAM Project Requires Adequate Quality Control

The GTAM Project is described by PG&E as the development of an electronic database whose intent is to collect, store and manage information related to the gas transmission system, moving away from paper. This effort is described as incorporating four major components:[87]

1. An upgrading of the current GIS to track, manage and store all pipeline asset data (e.g., location/connectivity, specifications/features and maintenance/inspection history),
2. A materials tracking/tracing effort of pipeline com ponents from initial receipt by PG&E through its operating lifecycle in the field,
3. Electronic work management and scheduling "package" of various maintenance, inspection activities (e.g., mark and locate and leak survey), and
4. Integration of pipeline asset data including event history (leaks, dig ins, etc.).

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[85] PG&E Prepared Testimony, page 5-10.

[86] Direct Assessment is an assessment method specifically limited in federal pipeline safety regulation to certain types of corrosion risks given its restricted technical applications.

[87] PG&E Prepared Testimony, page 5-16.

In PG&E's own words: "PG&E's existing records management technology infrastructure is fragmented and consists of proprietary systems containing different types of gas transmission assets: maintenance and inspection data reside in nine different systems; asset/material specification data reside in five different systems; and, asset location/spatial data reside in two different systems. The existing systems are not integrated and current process for managing, maintaining, and utilizing asset data are cumbersome and time consuming."[88] "The GTAM Project will be implemented in four distinct phases over a period of approximately 3.5 years (fourth quarter 2011 through first quarter 2015)."[89] These four phases are described as:

Phase 0 - Traceability of assets and integration of leak reporting into core technology system (8 months, performed concurrently with Phase 1 efforts),

Phase 1 - Implement enhanced work, asset and integrity management for pipeline assets (~43 months),

Phase 2 - Corrosion and line equipment (14 months),

Phase 3 - Station equipment (11 months).

Basically, this effort appears to be an attempt by PG&E to centralize its pipeline asset/operation/maintenance/inspection into an electronic data base, apparently moving from the current decentralized (and more paper reliant) efforts associated within its field/division business units. Centralized control of important pipeline information can provide an additional layer of management control if prudent process change procedures are incorporated, avoiding some of the risks associated with decentralized business units and scattered data.

[88] From PG&E Prepared Testimony, page 5-20.

[89] From PG&E Prepared Testimony, page 5-21.

However, centralized control can also increase risks, if appropriate processes are not in place. Although PG&E t estifies that they are "committed to work with records management industry experts to conduct a thorough study of its data and records management systems…." [90] TURN is nevertheless concerned about this project's efforts, especially given PG&E's past history of not providing adequate checks and balances to avoid falsification, tampering, or possible destruction of important records or evidence by employees on matters critical to public safety and the prudent operation of the pipeline system.

Movement to an electronic database system can significantly increase the risks of tampering or data entry error either by field or management personnel, so the need for proper checks and balances before data is finalized or accepted into a master electronic database is supremely critical. PG&E has not provided sufficient detail in its testimony to permit TURN to conclude that such an electronic system will have sufficient checks and balances to prevent major critical data entry errors. The efficiency associated with more easily analyzing electronic data is of no value from a risk management perspective, if the entered data **<u>does not accurately represent what is in the field or can be easily tampered with because proper levels of security or checks and balances are missing</u>**. PG&E also needs to demonstrate that the GTAM processes will have sufficient checks and balances at various independent management levels to assure such safety critical data is accurate, entered properly, represents what is actually in the field, and is p roperly secured and backed up, so that tampering with critical data fields cannot occur, either from field personnel or management. Past practices also raise serious concerns or questions as to whether a "consulting approach" is appropriate, or truly represents the public's best interest.[91]

[90] From PG&E Prepared Testimony, page 5-17.

[91] For example, the testimony related to Topock hydrotesting concerning inaccurate technical testimony raises serious questions about the ability, will, or technical competence of PG&E to serve as an arbitrator on very important pipeline safety technical matters.

5. Evaluation of Cost Responsibility and PG&E's Past Practices as the Pipeline Operator

5.1. PG&E's Cost Responsibility Proposal Is Inadequate

Table 9 provides a summary of the proposed IP costs that PG &E is suggesting be borne by the shareholders ($319.8 million or 14.6% of the total proposed Phase 1 costs). Other additional shareholder costs have also been mentioned by PG&E in their testimony, but these additional costs of approximately $215.4 million in years 2010 and 2011 do not represent costs associated with PG&E's Phase 1 IP proposal. Rather, they are associated with the San Bruno rupture failure resulting from PG&E's management failures, the NTSB investigation, and related matters, and should no t be part of the IP shareholder allocation discussions. These additional costs have not been included in Table 1 or Table 2.[92, 93]

Table 9 - PG&E Proposed Shareholder Allocation for Phase 1 IP (In Millions $)[94]

Description	2011	2012	2013	2014	Total
2011 Implementation Plan Work					
2011 Expense Forecast (Including Contingency)	$220.7	–	–	–	$220.7
2011 In-Service Capital-Related Costs	1. 4	–	–	–	1.4
Work on Post-1970s Pipe					
Post-1970 MAOP Validation	38.5	36.4	11. 0	–	85.9
Post-1970 Strength Testing	0.5	6.4	1. 7	3.2	11.8
Total Implementation Plan (IP) Shareholder Costs	**261.1**	**42.8**	**12.7**	**3.2**	**319.8**

92 PG&E Testimony, Table 1-1, page 1-14.

93 National Transportation Safety Board ("NTSB"), Accident Report NTSB/PAR-11/01, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010, Adopted August 30, 2011.

94 PG&E Testimony, Table 1-1, page 1-14.

As a general matter, PG&E's suggestion that shareholders absorb only 14.6% of the total costs associated with thei r proposed Phase 1 IP cost of approximately $2.2 billion seriously understates the obligations that should be borne by the shareholders. Much of PG&E's IP proposal reflects the need to bring the company into pipeline safety regulatory compliance because of past PG&E mismanagement practices that culminated in the gas transmission pipeline rupture and San Bruno tragedy.[95] On many safety fronts, the effort and cost to now bring the gas transmission pipeline operation into compliance are substantially more si gnificant than that which would have occurred had PG&E management prudently complied with pipeline safety regulations, especially over the past ten years, to assure control of their system. Accordingly, PG&E's shareholders should be paying a much greater s hare of the Phase 1 proposed costs.

I understand that both Mr. Long and Mr. Marcus will be presenting cost responsibility principles and some specific cost responsibility proposals based on policy considerations and a review of forecast costs. This test imony supplements and supports that testimony in highlighting some of the ways in which PG&E's past practices have failed to comply with industry standards and federal pipeline safety regulations governing prudent pipeline operation in the areas of records - keeping, records management, and pipeline integrity assessment. I conclude that *if* PG&E had maintained proper records, had conducted pipeline replacement as scheduled in regulatory filings since 1985, and had complied with federal integrity management rules, a significant portion of the work presently scheduled for Phase 1 would be avoided or would already have been performed.

5.2. PG&E's Records Retention and Record-keeping Practices Deviated from Industry Standards

For gas transmission pipelines, no other var iable is as critical as the MAOP. No matter how complex the pipeline system, the need to provide auditable and

[95] National Transportation Safety Board ("NTSB"), Accident Report NTSB/PAR-11/01, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010, Adopted August 30, 2011.

verifiable MAOP records is similar for all gas transmission pipelines. The obligation to identify, maintain, demonstrate and defend MAOP determi nations (both within or outside the company) is an obligation and responsibility clearly placed squarely on the pipeline operator.[96] PG&E's inability to quickly demonstrate which pipeline segments had MAOP determined by a hydrotest is a serious indication of a breakdown in management processes and loss of control. As such, shareholders should bear the full responsibility associated with reestablishing confidence in MAOP for any pipeline segment within the system where hydrotesting was required and the reco rds cannot now be found. Past failure by PG&E management to retain critical records to verify MAOP are maintained are the responsibility of PG&E management, and any cost to reestablish such MAOP requirements that cannot be found should be borne by the shareholders, including the full $162.3 million of costs for the MAOP Validation project.

The NTSB recommended that PG&E: "Use the traceable, verifiable, and complete records located by implementation of Safety Recommendation P -10-2 (Urgent) to determine th e valid maximum allowable operating pressure, based on the weakest section of the pipeline or component to ensure safe operation, of Pacific Gas and Electric Company natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 hi gh consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing. (P-10-3) (Urgent)"[97] In other words, PG&E is to produce all records used to establish MAOP on HCA pipeline segments within the PG&E system where MAOP was not established through a prior hydrotest. This recommendation resulted from the misinformation contained in PG&E's GIS database system. It is not a new requirement as, after a pipeline rupture, the regulatory or

[96] For example, see federal pipeline safety regulation 49CFR§192.619, and CPUC Order 112 Section 401.4 "Change in Maximum Allowable Operating Pressure," dated 1961, and ASA B 31.1.8 - 1955.

[97] NTSB Report, Accident Report NTSB/PAR-11/01, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010," adopted August 30, 2011, p 76.

investigatory body will usually verify how the MAOP for a failed pipeline segment was determined and audit the company's records utilized to establish such a critical parameter.

PG&E testifies that the NTSB's need for ""traceable, verifiable, and complete" standards adds specificity to existing gas pipeline safety recordkeeping requirements and, in the case of pipelines that had been "grandfathered" under 49 C.F.R.§192.61(c), significantly modifies existing requirements. PG&E acknowledges this is a familiar standard in other industries such as the aircraft and nuclear generation industries." [98] However, PG&E appears to be trying to create the illusion that requirements to maintain certain critical information related to gas transmission pipelines and the requirement for hydrot esting are somehow new and were not required in the past operation of a gas transmission pipeline system.

PG&E's arguments that they were not required to keep certain important safety critical records on their pipeline system is without merit.[99] There is certain detailed information that a prudent pipeline operator will keep, even for pipelines that are many decades old, to assure they are meeting industry codes and standards that predate federal as well as California state minimum pipeline safety regulati ons.[100] It is important to not lose sight of one important fact - the serious misinformation in PG&E's GIS database was a major factor in the San Bruno rupture in that it contributed to PG&E's failure to properly evaluate manufacturing seam failure risks.[101]

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[98] From IP Prepared Testimony, page 5-6 and 5-7.

[99] PG&E tends to confuse MAOP, a term defined in federal pipeline safety regulation with MOP, or maximum operating pressure, a term defined internally within PG&E.

[100] For example, gas industry consensus standards especially related to MAOP, such as ASA or ASME B31 code, predate federal pipeline safety regulations by many decades.

[101] NTSB Report, Accident Report NTSB/PAR-11/01, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010," adopted August 30, 2011, p 1.

PG&E is apparently claiming that as a pipeline operator they are not required by safety regulations to keep or maintain certain important records, such as those related to hydrotesting or Maximum Allowable Operating Pressure ("MAOP") validation, for pipe lines installed prior to 1970 that have been "grandfathered" under §192.619(c).[102] Accufacts has investigated many different transmission pipeline operations across North America and the world and has found that prudent companies keep such important records to assist, as well as to protect, pipeline management in making important decisions concerning their operations. Such records are needed to assure that a proper "due diligence" is applied within the company management structure, as well as to assure that the company is in compliance with pipeline safety regulations. Such records should never be lost or destroyed regardless of the age of the pipeline.

There is certain key information that must be gathered, maintained, and protected by pipeline companies as a cost of doing business. Past hydrotesting and operating pressure records utilized to set current MAOP, regardless of the pipeline's age, definitely fall into this important critical information category. If PG&E cannot quickly produce adequate records proving hydrotesting or operating pressure information to validate the MAOP, then the cost to find, or recertify such pressures should fall to the company that lost such records, and their associated shareholders, not the ratepayers.

The claim that pru dent pipeline operators would not have maintained certain critical records until federal pipeline safety regulations were promulgated in the early 1970's is false. Hydrotesting was performed by gas transmission pipeline operators well before 1970.[103] Critical pipeline work performed in the early 1950's advanced the technical understanding of the importance of high pressure

[102] PG&E Testimony, page 5-6.

[103] Evangelos Michalopoulos and Sandy Babka – Task Report, "Evaluation of Pipeline Design Factors," Prepared for Gas Research Institute, February 2000, page 20.

hydrostatic, or hydrotesting, to prove pipe integrity. [104] Many of these strength testing efforts were codified in industry standards in 1955, capturing and recognizing the importance of prudent strength tests.[105] Indeed, PG&E itself admits that "after adoption of [ASA B31.1.8 -1955] PG&E's practice was to follow ASA B31.1.8 -1955, including pre -service testing." [106] But PG&E now can't locate all the records of that testing.

The CPUC in GO 112, implemented on July 1, 1961, also recognized the importance of strength testing, especially hydrotesting, and required all new gas transmission pipelines to perform such important minimum strength testing. Prudent pipeline operators retain and protect such important hydrotesting records in a form that can be quickly obtained within the company for the life of the pipeline.

If costs have been included in PG&E's Pipeline Modernization Program because historical hydrotesting records cannot now be found or readily produced by PG&E, that additional cost to now bring the system into compliance should be borne by PG&E and its shareholders. Such test records should go back to at least 1955 unless supplanted by more recent tests, records of which should be readily produced.

PG&E's data show that over 65% of the pipeline scheduled for testing has already been strength tested, but PG&E has "complete" test records for only 7% of the mileage. [107] Likewise, about 50% of t he pipeline scheduled for replacement

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[104] Wesley B. McGehee, "Maximum Allowable Operating Pressure (MAOP) Background and History," prepared for Gas Research Institute, revised June 1998, page E-9.

[105] American Standards Association (ASA) B31.1.8 – 1955, establishing strength test for class locations.

[106] PG&E Response to DRA DR 045-07(a), included in Attachments.

[107] I use "tested" broadly to indicate the presence of some data in any of the relevant categories in the PSEP database that indicates that a strength test had been performed at some point in the past.

has already been tested, but PG&E has "complete" test records for only 5% of the mileage. To the extent these records are not found during the MAOP Validation, PG&E shareholders should pay for any resulting work.

5.3. PG&E's Past Transmission Integrity Management Program ("TIMP") Assessments were unreasonably focused on Direct Assessment

The apparent serious deficiencies in PG&E's TIMP have contributed to the lack of proper threat identification and remediation, and the cat ch-up work required in this PSEP. TIMP regulations, which have been in effect for approximately 10 years, basically requires an operator, to evaluate all threats to their pipeline on segments of their pipeline designated as HCAs, to perform a phased baseli ne assessment within 10 years, and to perform periodic reassessments at least every seven years. Assessment methods are chosen from a series of limited regulatory choices based on the threats to the pipeline segments.

Table 10 is a summary of PG&E's baseline assessments, by type of assessment, from 2002 though 2010.[108] By regulation, baseline assessments must be completed by December 17, 2012. The last column in Table 10 indicates that through 2010, an u nusually high percentage of PG&E's baseline assessments relied on DA ("Direct Assessment"), an assessment method clearly restricted in federal pipeline safety regulations to only deal with certain types of corrosion threats.[109] Very few gas transmission pip eline miles in this country contain only threats that can be addressed via DA techniques. While not acknowledged in the PM Plan, the unusually high reliance on DA and very little use of ILI or hydrotesting in the Baseline Assessments indicated in Table 10, also raises serious questions about the appropriateness and completeness of the PG&E Baseline and HCA reassessments completed to date in PG&E's TIMP.

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[108] PG&E Testimony, Table 2-5, page 2-17.

[109] 49CFR§192.923 details how direct assessment is to be used and for what threats.

Table 10: PG&E's Baseline Assessment 2002 – 2010

Assessment Method	Miles	% of System Total HCA Mileage [(a)]	Distribution of Assessment Method for Period (%)
HCA Pipe Assessed Through ILI	171	16.5	20.5
HCA Pipe Assessed Through DA	649	63.2	77.8
HCA Pipe Assessed Through Pressure Testing	14	1.4	1.7
Total HCA Pipe Assessed	834	81.1	100

(a) See Table 1 for Total HCA mileage reported by PG&E for their gas transmission system.

Under federal pipeline safety regulations, PG&E is reporting that 1027 miles, as of the beginning of 2011, are in High Consequence A reas, or HCAs. Errors made by the PG&E pipeline management in selecting and using the wrong assessment method permitted by integrity management ("IM") regulations should be paid by the company and its shareholders, especially if the company must play expensive catch-up for failures associated with poor past IM practices. In particular, if segments of the PG&E Phase 1 IP are driven by the necessity to bring the PG&E system into compliance with the current TIMP regulations because of past non -compliance, then the costs to bring such systems now into regulatory compliance should be borne by shareholders, not the ratepayers.

For example, if PG&E had utilized more appropriate testing methods, it is quite possible that it may have sooner discovered certain problems, such as the longitudinal seam weld problems on Line 132. At a minimum, PG&E's spending on ECDA for 2002-2010 was likely a waste of ratepayer funds.

Table 11 below is an estimate of the miles that would be assessed/replaced under the PG&E proposed Phase 1 effort through 2014. Project costs are based on information supplied in the PG&E's Prepared Testimony.

Table 11: PG&E's Proposed Project Modernization Phase 1 (2011 – 2014) miles and costs[110]

	Miles	Total Cost (in Millions $)	Cost/mile (millions $ /mile)
Pipeline Replacement Forecast	185.7	834.2	4.49
Pipeline ILI Forecast (upgrade and analysis)	233	39.99	.172
Strength Test Forecast (expense and capital)	783	411.3	.525
Total	1,201.7	1285.5	

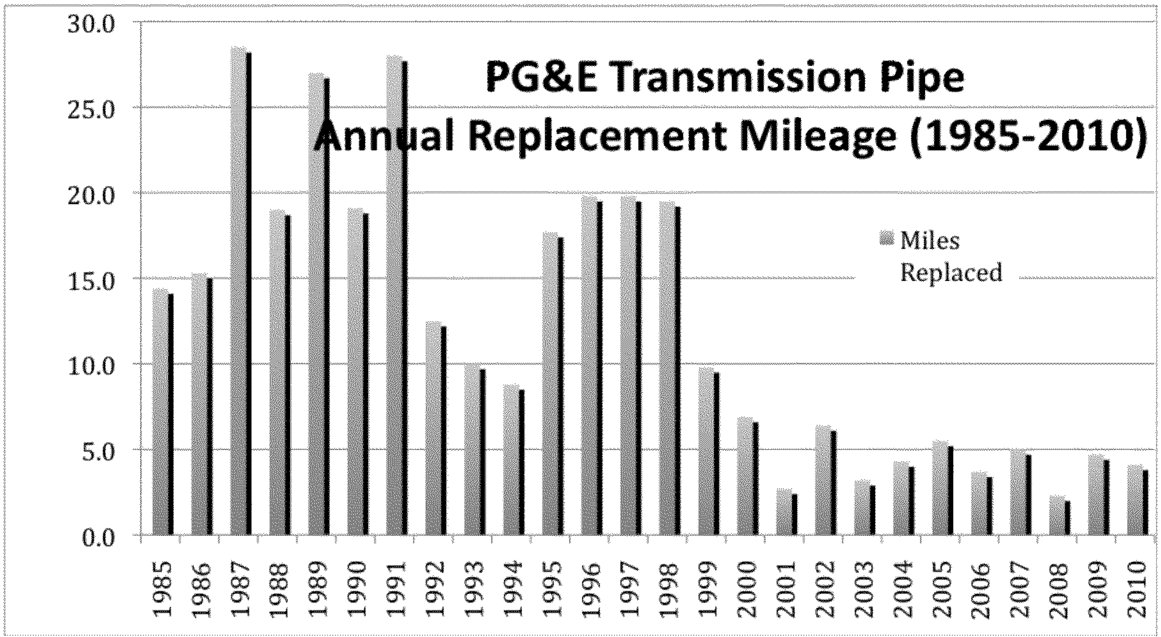
Based on Table 11, after Pha se 1 is complete d, only about one -third of PG&E's pipeline system within HCAs would have been or can be inspected via ILI. This is a relatively low percentage of their system given the advantages of man y ILI technologies to reliable determine many types of certain at -risk anomalies. This low percentage of ILI mileage is due to past PG&E management misapplication and overreliance on Direct Assessment. TURN encourages the conversion to ILI, but has to ra ise the question as to how much additional cost is related to playing catch-up because the past PG&E management failed to properly focus on the prudent conversion to ILI over the almost ten years that IM regulation has been in effect.

Moreover, not only did PG&E excessively rely on DA in its integrity management program, it significantly reduced its pipeline replacement work. As part of its Gas Pipeline Replacement Program, PG&E had forecast replacing about 23.2 miles per year for 20 years. PG&E replaced a n average of 17.9 miles per year of transmission pipe in 1985-1999. After it transitioned to a risk

110 From IP, Table 3-3, page 3-63 and Table 3-4, page 3-64, and Table 3-5, page 3-65. The cost projections are PG&E's, and TURN does not concur with these unusually high or possibly skewed cost projections/estimates.

assessment based replacement program, PG&E's transmission pipeline replacement dropped dramatically to an average of 4.4 miles per year in 2000 - 2010, as illustrated in Figure 13.[111]

Figure 13: PG&E Pipeline Replacement, 1985-2010



The above Figure strongly suggests that PG&E's misplaced reliance on DA caused it to significantly curtail pipeline replacement. PG&E's IP now appears to be an effort to play catch-up.

5.4. Cost Forecasting Issues

Below I comment briefly on PG&E's unit cost forecasts. Since I believe the scope of work for the PSEP should change significantly, both due to changes in the decision tree as well as due to the MAOP validation and updating of the PSEP Database, I only discuss some of the unit costs forecasts.

[111] Based on PG&E Responses to TURN DR 05-Q3Att01, DR 010-01(a), DR 10-07 and DR 12-01; included in Attachments. PG&E has provided some conflicting numbers for pipeline replacement, apparently based on changes in historical accounting procedures.

5.4.1. Hydrotest Costs

PG&E has recently asserted that hydrotesting cost, estimated at $525,000/mile in the IP proposal, is now spiraling to above $1,200,000/mile.[112] In general, I find PG&E's cost forecasts to be high compared to published data, and compared to the costs I experienced in hydrotesting many pipelines in California and more recently in Washington state and other locations. I cannot determine whether PG&E's high costs are due to incorrect estimates, inflated costs due to the timing and magnitude of the project, or a combination.

These higher costs are well above the range cited in the NTSB San Bruno report; "PHMSA regulatory evaluat ion prepared in connection with the gas integrity management rulemaking indicated that, based on estimates provided by the Interstate Natural Gas Association of America (INGAA) and the American Gas Association (AGA), the cost per mile for hydrostatic testi ng of a gas transmission pipeline was $29,700 –$40,000 in 2001."[113] There is a very high probability that PG&E is projecting and forecasting overstated hydrotest costs that do not actually represent the real costs if such hydrotesting efforts were more prude ntly scheduled, implemented, and managed.

Hydrotesting costs incurred during the past year by PG&E are probably not representative of normal hydrotesting costs, and all such hydrotest records utilized for such cost claims should be independently audited/analyzed to assure that they are accurate and represent only the cost to perform a hydrotest

Hydrotest costs can easily spiral out of hand if a "no limit, spare no expense, around the clock, unlimited resource philosophy" is followed in a rush to catch up on needed hydrotesting assessments. I suspect that PG&E has been following

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[112] Article by Aaron Selverston, "PG&E Grilled by Council Over Pipeline Safety," Palo Alto Patch, November 15, 2011.

[113] National Transportation Safety Board ("NTSB"), Accident Report NTSB/PAR-11/01, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010, Adopted August 30, 2011, page 83.

this philosophy this past year. Such unusual costs would not represent the actual hydrotest cost that a prudent operator would expect to incur.

5.4.2. Pipe Replacement Costs

Under PG&E's proposal pipeline replacement forecasts are almost 10 times greater on a cost per mile basis than hydrotesting.[114] The replacement decisions in PG&E's IP need to be carefully evaluated as to the reasons actually driving such a costly replacement step for each identified segment. New pipe is not necessarily better than old pipe as demonstrated by pipeline problems and failures associated with many recent new pipelines. There are numerous management processes that need to come into proper play before new p ipe can be declared better than the pipe it may be replacing.

[114] PG&E Testimony, Table 3-3, page 3-63 and Table 3-4, page 3-64, and Table 3-5, page 3-65.

Photo 1 – Large diameter gas pipeline rupture

SB_GT&S_0497437

Photo 2 – Aerial View of San Bruno Pipeline Rupture Fire

Photo 3 - San Bruno Aerial View of the Aftermath

Note ejected pipe (circle) in street

Photo 4 – Example of delayed valve shutoff, 36-inch gas pipeline and First Responders