Docket No. SA-534

Exhibit No. 2-DT

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C.

CPUC and PG&E Correspondence regarding the San Bruno Accident since Dec 16 2010

(72 Pages)

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

December 16, 2010

Christopher Johns, President
Pacific Gas and Electric Company
P.O. Box 770000
Mail Code B32
San Francisco, California 94177

Re: Safety Response to the National Transportation Safety Board Advisory of December 14, 2010

Dear Mr. Johns:

On December 14, 2010, the National Transportation Safety Board ("NTSB") issued an advisory finding that some of the pipe segments removed from Pacific Gas and Electric Company's ("PG&E's") Line 132 following the San Bruno explosion of September 9, 2010, had longitudinal seams that were fusion-welded from both inside and outside the pipe, but "some were fusion-welded only from the outside of the pipe."

Given the NTSB's preliminary finding, I direct that PG&E take the following actions.

1. PG&E shall reduce, to 20% below the Maximum Allowable Operating Pressure for each line, the maximum pressure on pipelines that have segments that meet all of the following characteristics:
    a. all Class 3 & 4 pipelines and all Class 1 & 2 pipelines located in High Consequence Areas (gas transmission lines as defined by 49 CFR 192.3); and
    b. 30-inch diameter pipelines having Double Submerged Arc Welds or its manufacturing equivalent; and
    c. installed prior to January 1, 1962, and having not undergone hydrostatic pressure testing or the equivalent.

2. PG&E shall assess the integrity of the pipelines described above, using one of the following four methods:
    a. Hydrostatic or other appropriate pressure test (see 49 CFR 192, Subpart J); or
    b. X-ray; or
    c. a camera examination of the interior of the pipe; or
    d. an inline inspection using a "smart pig" or other technology appropriate to assessing pipeline seam integrity.

3. PG&E must obtain Commission authorization before repressurizing any gas transmission pipelines that have their pressure reduced pursuant to this directive. To obtain such authorization, PG&E shall submit to the Commission information:
    a. identifying pipeline segments described in this directive; and
    b. assessing the condition of the segments identified in this directive; and
    c. setting forth all actions taken to meet these directives including a description of the actions taken to make the pipeline segments safe for a return to normal pressures.

Should PG&E find that any of these directives would directly and adversely impact PG&E's obligation to serve core gas customers, PG&E shall promptly notify me.

Sincerely,

[redacted]

Paul Clanon
Executive Director

Pacific Gas and Electric Company™

Brian K. Cherry
Vice President
Regulatory Relations

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January 7, 2011

Paul Clanon, Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: CPUC January 3, 2011 Directives in Response to NTSB Safety Recommendations

Dear Mr. Clanon:

PG&E is fully committed to working expeditiously and cooperatively with the Commission to restore public confidence in the safety and integrity of our natural gas transmission system. Ensuring the completeness and the accuracy of PG&E's system records is absolutely fundamental to this effort. Accordingly, our customers and the Commission have PG&E's pledge that verifying its gas system records is among PG&E's most immediate and highest priorities.

As you know, following the San Bruno accident, we discovered a discrepancy in our records. A discrepancy of this nature is not acceptable to us. We initiated a comprehensive records review for the approximately 150 miles of transmission pipeline on the San Francisco Peninsula.

Your directive following this week's National Transportation Safety Board (NTSB) recommendations calls on us to extend this type of review to approximately 1,800 miles of transmission pipelines in class 3 and class 4 locations and class 1 and class 2 high consequence areas throughout our service area. Your January 3, 2011, letter directed PG&E to undertake specific actions in response to the NTSB recommendations and requested that we confirm by today whether this work could be completed by February 1, 2011.

PG&E recognizes and supports the urgency surrounding this work and is moving forward aggressively. Our first step, already under way, is to gather all hydrostatic and other pressure test information to verify which pipeline segments have had their maximum allowable operating pressure established through pressure testing. Although we maintain a centralized data base that indicates that the majority of the 1,800 miles of pipeline have been pressure tested, we understand that your directive requires us to review and verify the original paper records, which currently are kept in local offices and records storage facilities. As part of this process, we will also be collecting images of the original records in a centralized system, which is consistent with our understanding of your request.

This is a substantial undertaking. We are marshalling both internal and significant external resources, and we will deliver the results of our pressure testing verification work to you on March 15, 2011. We commit to providing you with a status update on February 1, 2011, including a plan for our records verification work, and regular updates thereafter.

The maximum allowable operating pressures on our pipelines are established in accordance with federal and state regulations and industry practice. We understand that this is a national issue that may result in future changes to those rules, and look forward to working with you in that effort.

Sincerely,

[redacted]

Brian K. Cherry
VP, Regulatory Relations

cc: Julie Fitch, Energy Division
Frank Lindh, General Counsel

Pacific Gas and Electric Company®

Brian K. Cherry
Vice President
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February 1, 2011

Paul Clanon
Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: CPUC January 3, 2011 Directive in Response to NTSB Safety Recommendations

Dear Mr. Clanon:

In our January 7, 2011, letter to you we committed to provide the California Public Utilities Commission (Commission) with an update of our progress in fulfilling the directives in your January 3, 2011 letter, ratified by the Commission through Resolution L-410 on January 13, 2011. PG&E is aggressively and diligently working to meet the expectations of the Commission to perform our records review and verification work by March 15, 2011. This letter provides an update on PG&E's work and plan going forward.

The Commission's directive applies to over 1,800 miles of gas transmission pipelines in Class 3 and Class 4 locations, and Class 1 and 2 high consequence areas throughout PG&E's service territory. Consistent with federal regulations, not all of these lines require a pressure test-established maximum allowable operating pressure (MAOP); nevertheless, we are in the process of verifying the number of these pipeline miles for we have records of pressure tests, containing the information required by 49 C.F.R. § 192.517(a).

The foundational step and PG&E's initial focus have been collecting, scanning and indexing an estimated 1.25 million individual records associated with approximately 2,750 "job numbers" from PG&E's hard copy records into its electronic database. It is critical to the remainder of this records verification and validation effort that this first step provide comprehensive, high quality electronic documentation of PG&E's gas transmission system. Toward that end, the entire process is being subjected to detailed quality assurance oversight, as described in more detail below.

As part of the first phase of this records verification project, PG&E has taken the following actions:

- PG&E's business lead for this records verification project reports directly to the Senior Vice President, Engineering & Operations. The business lead oversees an internal team of over 50 engineers, estimators, mappers, information technology specialists and managers dedicated exclusively to the project; this team will continue to grow.

- PG&E has retained numerous leading external partners to lend specialized expertise and significant additional resources to this process in the areas of document management, process controls, engineering, pipeline pressure calculations, and auditing. For example, Iron Mountain, Inc., a leading global document management company, is dedicating over 230 staff to assist PG&E in timely completing the document collection, scanning and indexing operation.

- PG&E has leased new space to house the record verification operations as well as built out space in its existing facilities to accommodate this activity.

Progress to date on this project includes:

- Document scanning and indexing operations are proceeding 24 hours-a-day, seven days-a-week.

- PG&E has collected hundreds of boxes of original records from over 20 field office and other locations across the service territory.

- At this stage, PG&E is scanning and indexing tens of thousands of these documents each day.

PG&E is using the scanned and indexed records to verify the completeness of pressure test records and other applicable records used to establish each line's MAOP per industry standards and federal code compliance. Over the next six weeks, PG&E will determine the total number of miles for which it has complete, verifiable and traceable records of prior pressure tests.

At the same time, PG&E will start the process of using all available verified records identified in the collection, scanning and indexing process to compile a segment-by-segment pipeline features list (PFL). Where necessary, PG&E will perform excavations to verify pipeline features. In the end, as directed by the Commission, MAOP will be validated based on the weakest segment in these Class 3 and 4, and Class 1 and 2 HCA transmission pipeline sections.

PG&E is dedicated to taking all steps to ensure the safety and integrity of our gas pipeline systems, including the monumental effort of verifying the underlying records of over 1,800 miles of pipeline by March 15th. In the meantime, however, if you have any questions, please do not hesitate to contact me.

Sincerely,

Brian K. Cherry
VP Regulatory Relations

cc: Michael R. Peevey, President
Mike Florio, Commissioner
Catherine Sandoval, Commissioner
Timothy A. Simon, Commissioner
Julie Fitch, Energy Division
Richard Clark, Consumer Protection Safety Division
Julie Halligan, Consumer Protection Safety Division
Frank Lindh, General Counsel
Harvey Y. Morris, Legal Division
Patrick S. Berdge, Legal Division
Joe Como, Division of Ratepayer Advocates

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

February 2, 2011

Christopher Johns, President
Pacific Gas and Electric Company
P.O. Box 770000
Mail Code B32
San Francisco, California 94177

Re: Directions in Response to Notification of Increased Pressurization Events

Dear Mr. Johns:

The California Public Utilities Commission ("Commission") has conducted a staff level investigation of Pacific Gas and Electric Company's ("PG&E's") planned and unplanned pressurization events where the pressure has risen above the Maximum Allowable Operating Pressure ("MAOP") in several of PG&E's gas transmission lines. Portions of these gas transmission lines are located in High Consequence Areas ("HCAs").

Given the information obtained to date, I direct PG&E to take the following actions:

1. PG&E shall reduce the operating pressure by 20% below the MAOP, as defined in 49 CFR 192, of the following transmission lines that have segments located in HCAs: Line 148, DFM 0805-01, DFM 0807-01 and DFM 1816-01. PG&E shall maintain these pressure reductions until such time as the Commission allows PG&E to return the lines to their normal operating pressures.

2. PG&E shall reduce the operating pressure by 20% below MAOP, as defined in 49 CFR 192, for any additional transmission lines that have segments located in HCAs that are found, through further investigation, to have experienced planned or unplanned events in which the segments experienced pressure greater than 110% of MAOP, as defined in 49 CFR 192. PG&E shall maintain these pressure reductions until such time as the Commission allows PG&E to return the lines to their normal operating pressures.

To the extent there is a reasonable possibility that any of the above ordered pressure reductions could adversely affect service to core customers, PG&E will consult with the Commission concerning appropriate actions to address adverse customer impacts.

Sincerely,

[redacted]

Paul Clanon
Executive Director

Pacific Gas and
Electric Company®

Brian K. Cherry
Vice President
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October 4, 2010

Paul Clanon, Executive Director
California Public Utilities Commission
505 Van Ness
San Francisco, CA 94192-3298

Re: PG&E's Response to CPUC Resolution L-403

Dear Mr. Clanon:

In your letter to PG&E dated September 13, 2010 and in the Commission's Resolution L-403, PG&E was directed to take several actions with respect to its natural gas transmission pipelines. This letter transmits PG&E's response to Items 4, 9 and 10 in the September 13, 2010 letter and Ordering Paragraphs 13, 18, 19 and 20 of Resolution L-403.

<u>Resolution L-403, Ordering Paragraph 13</u>

In combination, Item 4 in the September 13, 2010 letter and Ordering Paragraph 13 Resolution L-403, require the following:

> ***PG&E shall evaluate records of customer natural gas leak-complaint response times and response effectiveness system-wide, take immediate mitigation measures if deficiencies are found, and report the results to the Executive Director within ten (10) days of the date of Resolution L-403***

As stated in its September 20, 2010 letter, PG&E does not have any record of customer leak "complaints" in 2010. In the normal course of business, PG&E does receive calls from customers regarding possible gas odors and gas leaks. When a customer calls PG&E's contact centers to report a suspected gas odor or gas leak, the calls are classified as field orders requiring either "immediate response" or "same day" response. This distinction takes into consideration a number of factors including whether the customer can hear hissing or blowing and how strong the odor is. Additionally, even if these conditions are not met, if the customer seems anxious, the field order is issued as an immediate response order.

PG&E has set an internal goal of responding to 94 percent of all immediate response calls in one hour or less from when the call is received. The immediate response metric takes into consideration calls from customers, as well as all other calls that require immediate response (e.g., calls from emergency service agencies, gas leaks called in by PG&E employees or contractors performing system leak surveys, calls from third-party contractors who may find a potentially hazardous gas leak or carbon monoxide issue while providing weatherization services to customers).

Year to date through September 15, 2010, system-wide PG&E has responded to 94.2 percent of all immediate response calls within one hour, with an average response time of 33 minutes and 24 seconds. Also, year to date through September 15, 2010, PG&E has responded to 97.5 percent of all same day gas leak and gas odor calls within 12 hours, with an average response time of 3 hours and 33 minutes.

Each week, missed immediate response field orders are reported and reviewed to identify trends, root causes and areas requiring improvement. The primary drivers of missed immediate response field orders are: 1) immediate response calls received during times when field staffing is lower, (e.g., during the swing shift (typically from 4 p.m. to midnight) and the graveyard shift (typically from midnight to 8 a.m.)); 2) changing field conditions requiring the transfer of the field order from the initial field employee to a second field employee; 3) field employees delayed due to the need to complete an in-progress field order; and 4) long travel times due to field employees covering large, sparsely populated geographic areas or traffic delays during heavy travel times. PG&E promptly addresses deficiencies in its process through training, modifications to staffing, and discipline as appropriate.

<u>Resolution L-403, Ordering Paragraphs 18 and 19</u>

In combination, Item 9 in the September 13, 2010 letter and Ordering Paragraphs 18 and 19 of Resolution L-403, require the following:

> ***PG&E shall review the classification of its natural gas transmission pipelines and determine if the classifications have changed since the initial designation. PG&E shall report the results of its review of the classification of its natural gas transmission lines and any subsequent changes to those classifications since PG&E's initial designation to the Executive Director within ten (10) days of the date of Resolution L-403.***

PG&E interpreted this directive to mean that it would review its facilities and records to determine if field conditions have changed to warrant a reclassification of any segment of its pipelines. PG&E completed the review of its gas transmission pipelines operating at pressures greater than 60 pounds per square inch gauge (PSIG) totalling approximately 6,700 miles of pipeline as directed. PG&E's review utilized its gas transmission pipeline database to compare the classification recorded at initial installation to the current classification. This comparison identified 1,057 miles of pipeline where the current classification is different from the initial classification.

Resolution L-403, Ordering Paragraph 20

In combination, Item 10 in the September 13, 2010 letter and Ordering Paragraph 20 of Resolution L-403, require the following:

> ***PG&E shall investigate and report to the Commission PG&E's forecasted versus actual levels of spending on pipeline safety and pipeline replacements from 2003 to the present within ten (10) days of the date of Resolution L-403.***

PG&E interpreted this directive to apply to pipelines covered by Gas Transmission and Storage rate cases and provides the details of the required comparison in Attachment 1 to this letter. In summary, PG&E actually spent $698 million, or $23 million more than authorized for the period 2003 through 2009 for work specific to pipeline safety and replacement as determined by examining expenditures in PG&E's work categories for Integrity Management, Pipeline Reliability, System Maintenance, and Mark and Locate.

Please contact me if you have any questions about this report or other matters related to PG&E's natural gas transmission system.

Sincerely,

[redacted]

Brian K. Cherry

Attachment

cc: Patrick Berdge, Legal Division
Joe Como, Division of Ratepayer Advocates

Gas Pipeline Safety and Replacement
2003 through 2009
($ millions)

Line			2003 Recorded	2003 Authorized	2003 Variance	2004 Recorded	2004 Authorized	2004 Variance	2005 Recorded	2005 Authorized	2005 Variance
		GAS TRANSMISSION - EXPENDITURES									
1		Capital	89.0	71.5	17.5	81.2	71.5	9.7	118.9	87.6	31.2
2		Expense	76.9	77.9	(0.9)	80.9	92.9	(12.0)	85.5	89.4	(4.0)
3		Total	166.0	149.4	16.6	162.1	164.4	(2.3)	204.3	177.1	27.3
		GAS TRANSMISSION - TOTAL EXPENDITURES (Excluding Customer Driven Work)									
		Major Work Category									
		Gas Transmission Capital									
4	98	Integrity Management	10.6	0.0	10.6	12.1	11.1	1.1	19.3	15.8	3.5
5	75	Gas Pipeline Reliability	19.0	16.1	2.8	12.1	11.0	1.1	17.3	12.8	4.4
6		**Subtotal - Pipeline Safety & Replacement**	29.5	16.1	13.4	24.3	22.1	2.2	36.6	28.6	8.0
7	5	Tools & Equipment	0.4	0.2	0.2	0.1	0.2	(0.1)	0.4	0.2	0.2
8	12	Implement Environment Projects	0.4	4.3	(3.9)	0.4	0.5	(0.2)	1.7	0.9	0.8
9	76	Trans Reliability - Station	36.3	28.7	7.6	38.6	26.5	12.1	43.7	35.2	8.5
10	84	Trans Gathering System	2.5	1.6	0.9	1.5	1.4	0.1	0.9	1.2	(0.3)
11		***Total Capital***	69.2	50.9	18.2	64.9	50.8	14.2	83.4	66.2	17.2
		Gas Transmission Expense									
12	II	Integrity Management Prgm	1.6	0.0	1.6	5.1	7.1	(2.0)	6.1	7.9	(1.8)
13	BX	System Maintenance	49.8	51.3	(1.5)	49.8	56.7	(6.9)	53.5	55.5	(2.0)
14	DF - Trans.	Mark and Locate	1.4	0.0	1.4	1.2	0.0	1.2	1.3	0.0	1.3
15		**Subtotal - Pipeline Safety & Replacement**	52.8	51.3	1.5	56.0	63.7	(7.7)	60.9	63.4	(2.5)
16	AK	Manage Environmental Oper	1.9	2.5	(0.6)	2.1	2.6	(0.5)	2.7	2.5	0.2
17	AY	Habitat and Species Protection	0.2	0.3	(0.1)	0.1	0.3	(0.2)	0.1	0.2	(0.1)
18	CM	Oper Gas Transmission Fac	13.8	14.4	(0.6)	13.7	15.9	(2.2)	14.0	14.5	(0.5)
19	CR	Mnge Waste Disp & Transp	0.2	0.1	0.1	0.1	0.3	(0.2)	0.2	0.2	(0.0)
20	CX	Gas Marketing, Sales & Strategy	7.0	8.0	(1.0)	7.1	8.3	(1.2)	7.1	7.8	(0.7)
21	HB	Maint Gas Tran-Other	1.1	1.2	(0.1)	1.7	1.7	(0.1)	0.4	0.4	0.0
22	HA	Maint Gas Trn-Pol & Pln	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)
23		***Total Expense***	76.9	77.9	(0.9)	80.9	92.9	(12.0)	85.4	89.1	(3.7)
24		**Total Pipeline Safety & Replacement**	82.3	67.5	14.9	80.3	85.8	(5.5)	97.5	92.0	5.5
25		**Total (Excluding Customer Driven Work)**	146.1	128.8	17.3	145.8	143.6	2.2	168.8	155.2	13.5

Line			2006 Recorded	2006 Authorized	2006 Variance	2007 Recorded	2007 Authorized	2007 Variance	2008 Recorded	2008 Authorized	2008 Variance
		GAS TRANSMISSION - EXPENDITURES									
1		Capital	129.4	101.5	27.9	158.3	152.6	5.7	216.8	220.3	(3.5)
2		Expense	84.9	90.7	(5.8)	86.8	97.4	(10.6)	90.3	93.1	(2.9)
3		Total	214.3	192.2	22.0	245.1	250.0	(4.9)	307.0	313.4	(6.4)
		GAS TRANSMISSION - TOTAL EXPENDITURES (Excluding Customer Driven Work)									
		Major Work Category									
		Gas Transmission Capital									
4	98	Integrity Management	15.3	17.2	(1.9)	26.8	24.0	2.8	17.6	19.2	(1.6)
5	75	Gas Pipeline Reliability	15.0	15.8	(0.8)	19.9	18.8	1.1	16.5	19.9	(3.5)
6		**Subtotal - Pipeline Safety & Replacement**	30.3	33.0	(2.7)	46.7	42.8	3.9	34.1	39.1	(5.0)
7	5	Tools & Equipment	0.2	0.2	0.0	0.2	0.2	(0.0)	1.3	0.3	1.0
8	12	Implement Environment Projects	3.1	1.1	2.0	6.7	4.4	2.3	9.9	6.0	3.9
9	76	Trans Reliability - Station	49.2	40.7	8.5	53.0	53.9	(0.8)	64.0	58.4	5.7
10	84	Trans Gathering System	1.4	1.4	0.0	4.7	2.3	2.4	5.0	4.0	0.9
11		***Total Capital***	84.2	76.3	7.9	111.3	103.6	7.7	114.3	107.8	6.5
		Gas Transmission Expense									
12	II	Integrity Management Prgm	10.3	9.3	1.0	11.8	7.7	4.0	15.2	16.4	(1.3)
13	BX	System Maintenance	52.9	55.3	(2.4)	52.5	55.2	(2.7)	49.2	47.6	1.6
14	DF - Trans.	Mark and Locate	1.6	0.0	1.6	1.5	0.0	1.5	4.2	3.8	0.4
15		**Subtotal - Pipeline Safety & Replacement**	64.7	64.6	0.1	65.8	62.9	2.9	68.6	67.9	0.8
16	AK	Manage Environmental Oper	2.7	2.5	0.1	2.4	2.5	(0.1)	2.6	3.0	(0.5)
17	AY	Habitat and Species Protection	0.4	0.2	0.2	0.1	0.2	(0.1)	0.1	0.2	(0.1)
18	CM	Oper Gas Transmission Fac	10.1	14.8	(4.6)	10.4	11.3	(1.0)	10.9	11.2	(0.3)
19	CR	Mnge Waste Disp & Transp	0.3	0.3	(0.0)	0.2	0.1	0.1	0.3	0.3	0.0
20	CX	Gas Marketing, Sales & Strategy	7.0	8.0	(1.0)	7.8	9.2	(1.4)	7.7	9.7	(2.1)
21	HB	Maint Gas Tran-Other	0.0	0.5	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0
22	HA	Maint Gas Trn-Pol & Pln	0.0	0.0	0.0	0.0	1.2	(1.2)	0.0	0.0	0.0
23		***Total Expense***	85.2	90.7	(5.6)	86.7	87.5	(0.8)	90.2	92.3	(2.2)
24		**Total Pipeline Safety & Replacement**	95.0	97.6	(2.6)	112.4	105.7	6.7	102.7	107.0	(4.3)
25		**Total (Excluding Customer Driven Work)**	169.4	167.1	2.3	198.0	191.1	6.9	204.5	200.1	4.4

Line			2009 Recorded	2009 Authorized	2009 Variance	7 yr Recorded	7 yr Authorized	Variance	5 yr Recorded	5 yr Authorized	Variance	Line
		GAS TRANSMISSION - EXPENDITURES										
1		Capital	200.3	188.1	12.2	993.9	893.1	100.8	823.6	750.1	73.5	1
2		Expense	96.8	95.1	1.7	602.1	636.6	(34.5)	444.2	465.9	(21.6)	2
3		Total	297.2	283.2	13.9	1,595.9	1,529.7	66.3	1,267.9	1,216.0	51.9	3
		GAS TRANSMISSION - TOTAL EXPENDITURES (Excluding Customer Driven Work)										
		Major Work Category										
		Gas Transmission Capital										
4	98	Integrity Management	23.4	17.5	5.9	125.1	104.8	20.3	102.4	93.7	8.7	4
5	75	Gas Pipeline Reliability	28.5	30.3	(1.9)	128.3	124.9	3.4	97.1	97.7	(0.6)	5
6		**Subtotal - Pipeline Safety & Replacement**	51.9	47.8	4.0	253.3	229.6	23.7	199.5	191.4	8.1	6
7	5	Tools & Equipment	0.6	0.8	(0.2)	3.2	2.0	1.2	2.6	1.7	1.0	7
8	12	Implement Environment Projects	10.7	14.2	(3.5)	32.9	31.5	1.4	32.1	26.6	5.5	8
9	76	Trans Reliability - Station	70.8	68.8	2.1	355.7	312.1	43.6	280.8	256.9	23.9	9
10	84	Trans Gathering System	5.4	3.8	1.6	21.4	15.7	5.7	17.4	12.7	4.7	10
11		***Total Capital***	139.4	135.4	3.9	666.6	591.0	75.6	532.5	489.3	43.2	11
		Gas Transmission Expense										
12	II	Integrity Management Prgm	15.5	17.4	(1.9)	65.6	65.9	(0.3)	58.9	58.8	0.1	12
13	BX	System Maintenance	56.1	50.5	5.6	363.8	372.0	(8.2)	264.2	264.0	0.2	13
14	DF - Trans.	Mark and Locate	4.2	3.5	0.7	15.3	7.3	7.9	12.7	7.3	5.4	14
15		**Subtotal - Pipeline Safety & Replacement**	75.8	71.4	4.4	444.7	445.2	(0.5)	335.8	330.2	5.7	15
16	AK	Manage Environmental Oper	2.5	3.3	(0.8)	16.8	18.9	(2.1)	12.9	13.9	(1.0)	16
17	AY	Habitat and Species Protection	0.1	0.2	(0.1)	1.2	1.6	(0.4)	0.9	1.0	(0.1)	17
18	CM	Oper Gas Transmission Fac	10.5	11.6	(1.0)	83.4	93.6	(10.2)	55.9	63.4	(7.4)	18
19	CR	Mnge Waste Disp & Transp	0.2	0.3	(0.1)	1.5	1.7	(0.1)	1.2	1.3	(0.0)	19
20	CX	Gas Marketing, Sales & Strategy	7.3	8.2	(0.9)	51.0	59.3	(8.3)	36.9	42.9	(6.0)	20
21	HB	Maint Gas Tran-Other	0.0	0.0	0.0	3.2	3.9	(0.6)	0.4	0.9	(0.4)	21
22	HA	Maint Gas Trn-Pol & Pln	0.0	0.0	0.0	0.0	1.2	(1.2)	0.0	1.2	(1.2)	22
23		***Total Expense***	96.5	95.0	1.6	601.9	625.3	(23.5)	444.1	454.6	(10.6)	23
24		**Total Pipeline Safety & Replacement**	127.7	119.3	8.4	698.0	674.8	23.2	535.4	521.6	13.8	24
25		**Total (Excluding Customer Driven Work)**	235.9	230.4	5.5	1,268.5	1,216.3	52.1	976.6	943.9	32.7	25

Note:
Approved GT&S rate cases during the 2003-2009 time period did not result in a line item approval of spending in the various work categories. For this reason, the authorized amounts reflected are PG&E's estimates of the amount included in the final authorized rates

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October 25, 2010

Paul Clanon, Executive Director
California Public Utilities Commission
505 Van Ness
San Francisco, CA 94102-3298

Re: Updates on Natural Gas Transmission System

Dear Mr. Clanon:

In your letters to PG&E dated September 13, 2010, September 17, 2010, and October 15, 2010 and in the Commission's Resolution L-403 adopted on September 23, 2010, PG&E was directed to take several actions with respect to its natural gas transmission pipelines. This letter transmits PG&E's response to several directives, indicated below, as issued in your letters and incorporated into Resolution L-403:

Attachment 1: Assessment of gas transmission pipelines in the San Bruno area.
Item 2 in the September 13, 2010 letter and Ordering Paragraph 11 in Resolution L-403.

Attachment 2: Preliminary report on the replacement or retrofit of manually operated valves with automatically or remotely controlled valves on PG&E gas transmission pipelines.
Item 11 in the September 13, 2010 letter, Item 7 in the September 17, 2010 letter, and Ordering Paragraph 21 in Resolution L-403.

Attachment 3: Accelerated gas system survey initial report.
Item 3 in the September 13, 2010 letter and Ordering Paragraph 12 in Resolution L-403.

Attachment 4: Curtailment plans.
Items 1, 2, and 3 in the October 15, 2010 letter.

Please contact me should you have any questions.

Sincerely,

Brian K. Cherry
VP Regulatory Relations

cc: Michael R. Peevey, President
Timothy A. Simon, Commissioner
Dian M. Grueneich, Commissioner
John A. Bohn, Commissioner
Nancy Ryan, Commissioner
Julie Fitch, Energy Division
Richard Clark, Consumer Protection Safety Division
Julie Halligan, Consumer Protection Safety Division
Frank Lindh, General Counsel
Harvey Y. Morris, Legal Division
Patrick S. Berdge, Legal Division
Joe Como, Division of Ratepayer Advocates

ATTACHMENT 1

ASSESSMENT OF GAS TRANSMISSION PIPELINES IN THE SAN BRUNO AREA

The letter from Paul Clanon to PG&E dated September 13, 2010 (Item 2) and Ordering Paragraph 11 of Resolution L-403 directed PG&E to conduct an integrity assessment of all gas facilities in the impacted area.

PG&E responded on September 20, 2010, describing some of the immediate steps it had undertaken, including an accelerated survey of the gas transmission lines in San Bruno and the distribution system in and around the impacted San Bruno neighborhood. PG&E also committed to conduct instrument surveys to provide a more detailed assessment of the pipe and pipeline coating for all transmission mains in San Bruno.

On September 23, 2010, PG&E stated that it would perform instrument surveys over all gas transmission mains in San Bruno using Close Interval Survey (CIS), Direct Current Voltage Gradient (DCVG) and Pipeline Current Mapper (PCM) tools.

PG&E has completed this survey. It includes the 15.93 miles of transmission pipeline within 26 high consequence areas (HCAs), as well as some non-HCA transmission pipelines. The surveys included the portions of Lines 101, 109 and 132 within and extending outside the city bounds of San Bruno, as well as all distribution feeder mains. The CIS was performed at 10-foot intervals to ascertain if any potential cathodic protection deficiencies exist on the pipe. The DCVG survey was performed to identify any coating anomalies. The PCM survey was performed at 25-foot intervals along the pipeline to measure the depth profile of the pipelines.

PG&E did not identify during the survey any integrity issues that required immediate repair. The survey found one indication of a potential contact between the transmission line and the casing on Line 101, where Line 101 intersects with Highway 101.[1] Consistent with existing practices, PG&E will excavate the area immediately surrounding

[1] A casing is a larger pipe surrounding the pipeline carrying gas. Casings are not pressurized. They were required by CalTrans, railroad companies and other agencies when pipelines were built across their right-of-ways. Casings are designed to be separated from the pipeline by spacers and end seals to keep water and dirt out of the space between the pipe and the outer casing. Over time, they can shift in the ground or dirt and water can enter the casing; either scenario can lead to casing contact with the pipeline.

the detected casing/pipeline contact, conduct a visual examination to confirm contact, and take remedial actions if necessary.[2]

[2] Remedial action includes eliminating the contact or creating an inert (noncorrosive) environment.

ATTACHMENT 2

PRELIMINARY REPORT ON THE REPLACEMENT OR RETROFIT OF MANUALLY OPERATED VALVES WITH AUTOMATICALLY OR REMOTELY CONTROLLED VALVES ON PG&E GAS TRANSMISSION PIPELINES

The letters from Paul Clanon to PG&E, dated September 13, 2010 (Item 11) and September 17, 2010 (Item 7), and Ordering Paragraph 21 of Resolution L-403 directed PG&E to conduct a review of gas transmission line valve locations in order to determine a list of locations at which manual valves could be replaced by remotely-operated or automatic shut-off valves, an estimate of the costs of such replacement valves, and a description of the types of valves commercially available.

PG&E responded on September 20, 2010, affirming its commitment to conduct the review and provide the list and estimates requested.

SUMMARY

What follows is PG&E's preliminary report regarding the replacement or retrofit of manually operated valves with remotely controlled or automatic shut-off valves on its gas transmission system. PG&E proposes that this preliminary analysis be included in its Pipeline 2020 program and be reviewed by the CPUC and a third-party natural gas transmission expert in order to validate the analysis. Based on our preliminary analysis, PG&E estimates there are approximately 300 manual valves on over 565 miles of pipeline that should be further evaluated for potential replacement or retrofit.

There currently are no specific regulations governing the use of automated valves. As part of PG&E's Pipeline 2020 program, PG&E has engaged a third-party firm to review these preliminary conclusions and to provide recommendations in connection with the more detailed plan that PG&E will file with the Commission for its consideration. The firm will examine the specific requirements of PG&E's system, benchmark PG&E's practices against those of other pipeline operators, and assess the potential to replace or retrofit manually operated valves with remotely operated or automatic shut-off valves, as well as assess adding new valves. It will also identify associated enhancements to gas system operations, including protocols, training and system upgrades to enable effective use of the valve technology.

This study has begun and is expected to be completed by the end of the second quarter of 2011. PG&E will share the results of that comprehensive study with the CPUC.

BACKGROUND: Types and Uses of Automated Valves

There are two types of automated valves:

- Automated Remotely Controlled Valves (RCVs) allow a mainline valve to be opened and closed by a remote operator located at a gas control center.

- Automatic Line Rupture Shut-off Valves (ASVs) automatically close when they detect a line rupture (*e.g.* falling pressure, increasing flow rate) or any other condition that they are programmed to detect. These valves close without human intervention.

If a gas line is ruptured or there is another type of unplanned gas release, automated valves of either type can close the affected line much more quickly than a manually operated valve, isolating the ruptured section and reducing the volume of gas vented at the pipeline break. Automated valves do not prevent ruptures. Studies by pipeline experts indicate that most of the harm to persons and property following a natural gas pipeline rupture typically occurs within a few seconds or minutes of the initial rupture and energy release, before even an automated valve of either type can respond.

ASSESSMENT METHODOLOGY

PG&E considered a number of screening criteria to identify preliminary candidates for valve replacements, including:

- *Pipeline location*. PG&E's preliminary analysis focused on pipeline segments located within high consequence areas (HCAs) and took account of other environmental factors such as proximity to an earthquake fault, landslide areas, or major waterways.
- *Pipeline characteristics.* PG&E focused on a number of pipeline characteristics, including materials, age, diameter, operating pressure, and wall thickness.

PRELIMINARY ASSESSMENT RESULTS

Based on these screening criteria, PG&E identified approximately 565 miles of HCA pipeline for further evaluation. Within these 565 miles, PG&E estimates there are approximately 300 candidate valves for automation. PG&E is about one-third of the way through its evaluation of these candidate valves. Maps showing the general location of the valves in this first phase of evaluation are included as Appendix A.[3] A list of those general valve locations is included as Appendix B.[4] PG&E will continue to assess the remaining two-thirds of the candidate valves with the assistance of a third-party firm and provide a more detailed plan with the Commission as part of its Pipeline 2020 program.

RANGE OF POTENTIAL COSTS

The cost of valve replacements or retrofits is location-specific and varies significantly. Where the valve is easily accessible and requires only a retrofit, the cost could be as low as $100,000. In areas that are more difficult to access and require a valve replacement,

[3] A number of the candidate valves are located on the three parallel pipelines in the San Francisco Peninsula. These three pipelines provide gas to over 18% of PG&E's gas accounts. They are connected together (cross-tied) at various points along their route, beginning at Milpitas Terminal and ending in San Francisco. The potential valve replacement candidates shown in Appendix A include valves on both these mainline and crossties.

[4] PG&E will share more detailed valve location information with the Commission and local first responders.

the cost could be as high as $1,500,000.[5] Other factors affecting cost will be considered and addressed in our refined analysis. These factors include:

- The availability of a Supervisory Control and Data Acquisition (SCADA) communication points at the site;
- The availability of telecommunications and electric power facilities at the site;
- The scope of protocols, training and system upgrades and enhancements to ensure effective operation of the automated valve technology; and
- The complexity of isolating and taking portions of the system out-of-service to perform the installation work.

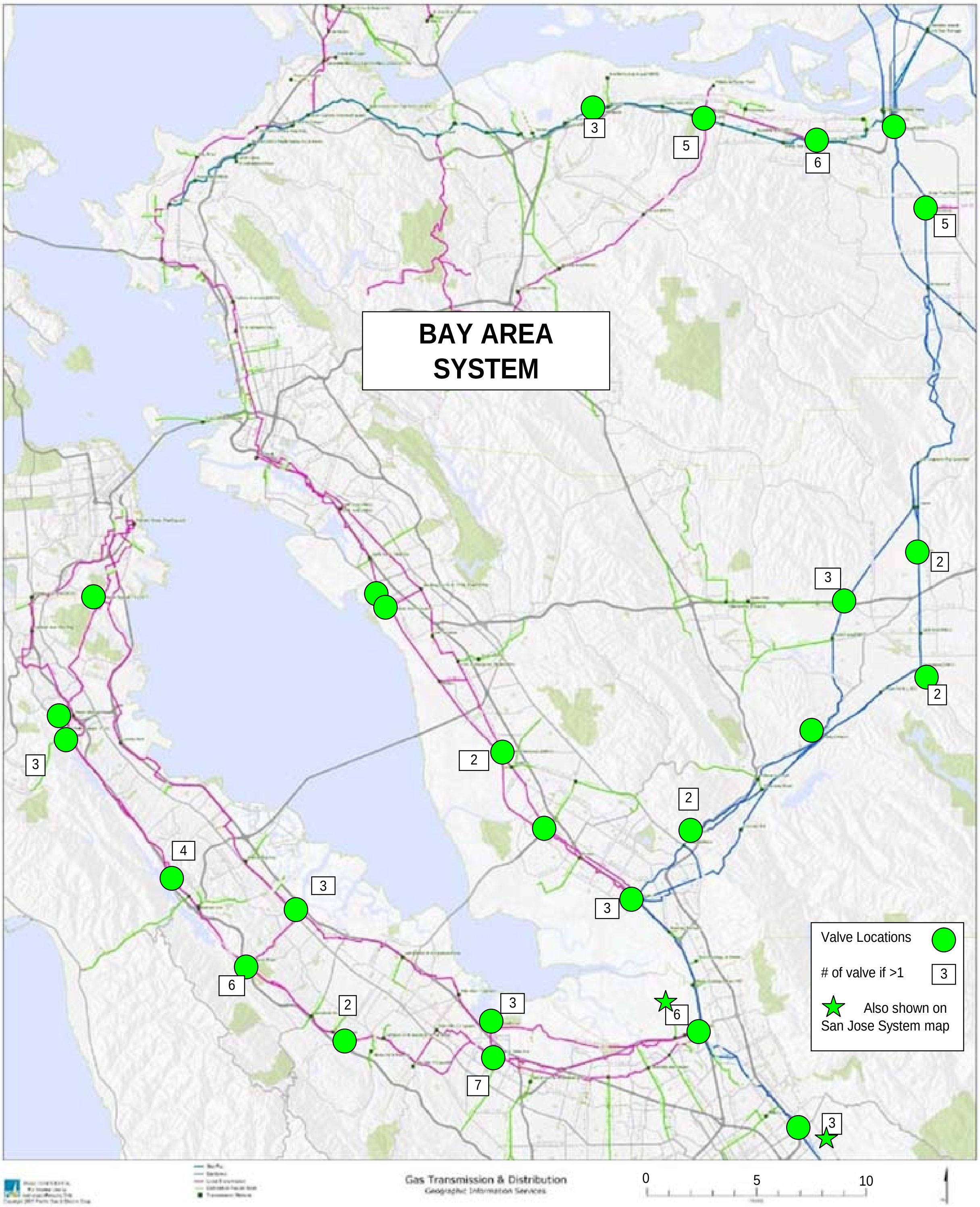
PG&E's estimates primarily reflect capital costs. Operation and maintenance costs, and costs for improving System Gas Control to provide increased oversight for remote control points have not been included in the cost estimates provided in this preliminary report, but will be included in the results of the comprehensive study.

NEXT STEPS

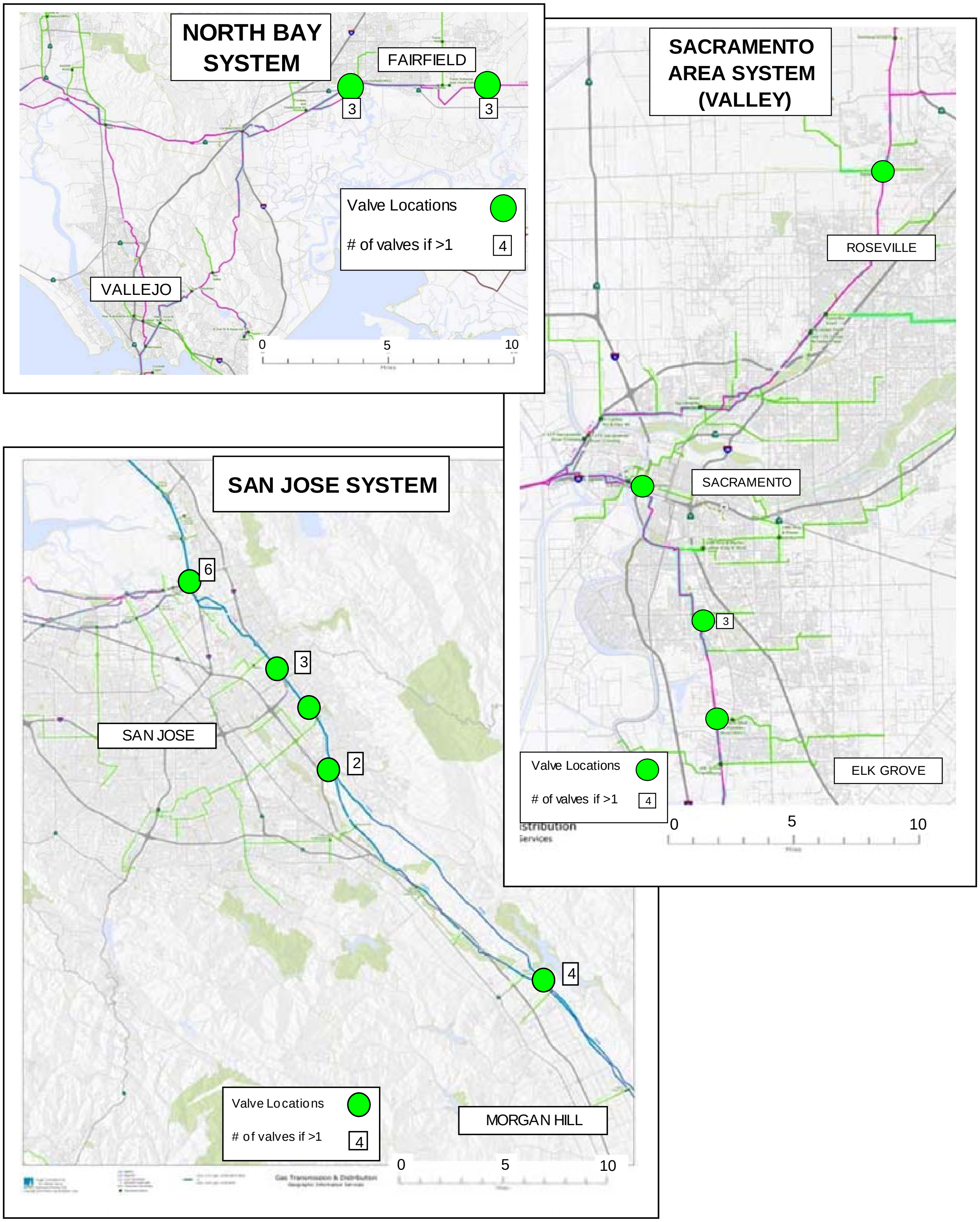
As part of the Pipeline 2020 program, PG&E has engaged a third-party firm to review and refine the preliminary analysis. The detailed study scope is included in Appendix C.

[5] Based on PG&E's past experience, the estimated average cost of installing a valve with automatic or remote controls at an existing manual valve for a large diameter (20" and larger) pipe is approximately $750,000.

APPENDIX A
Location of Potential Valve Replacement Candidates – Initial Evaluation



APPENDIX A, continued
Location of Potential Valve Replacement Candidates – Initial Evaluation



APPENDIX B
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
East Bay	L191	Antioch
East Bay	L191	Antioch
East Bay	SP-5	Antioch
East Bay	SP-5	Antioch
East Bay	SP-5	Antioch
East Bay	SP-5	Antioch
Bay Area Loop	L114	Brentwood, Unincorporated
Bay Area Loop	L114	Brentwood, Unincorporated
Bay Area Loop	L114	Brentwood, Unincorporated
Bay Area Loop	L303	Brentwood, Unincorporated
Bay Area Loop	L303	Brentwood, Unincorporated
Peninsula	L109	Hillsborough
Peninsula	L132	Hillsborough
Peninsula	L132	Hillsborough
Peninsula	L132	Hillsborough
East Bay	SP-3	Concord
East Bay	SP-3	Concord
East Bay	SP-3	Concord
Peninsula	L132B	Daly City
Sac Valley	L108	Elk Grove
Bay Area Loop	L107	Fremont
East Bay	L153	Fremont
Bay Area Loop	L303	Fremont
Bay Area Loop	L107	Fremont
Bay Area Loop	L131	Fremont

APPENDIX B, continued
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
Bay Area Loop	L131	Livermore
Bay Area Loop	L131	Livermore
Bay Area Loop	L131	Livermore
Bay Area Loop	L114	Livermore
Bay Area Loop	L303	Livermore
Bay Area Loop	L131	Alameda County
Bay Area Loop	L114	Livermore
Bay Area Loop	L303	Livermore
Peninsula	L109	Menlo Park
Peninsula	L132	Menlo Park
San Jose	L100	Milpitas
Peninsula	L101	Milpitas
Peninsula	L109	Milpitas
Peninsula	L132	Milpitas
Backbone	L300A	Milpitas
Backbone	L300B	Milpitas
Backbone	L300A	Morgan Hill
Backbone	L300A	Morgan Hill
Backbone	L300B	Morgan Hill
Backbone	L300B	Morgan Hill
Peninsula	L101	Mountain View
Peninsula	L101	Mountain View
Peninsula	L101	Mountain View
Peninsula	L109	Mountain View
Peninsula	L109	Mountain View

APPENDIX B, continued
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
Peninsula	L109	Mountain View
Peninsula	L132	Mountain View
Peninsula	L132	Mountain View
Peninsula	L132	Mountain View
Peninsula	L132A	Mountain View
East Bay	L153	Newark
Bay Area Loop	L303	Oakley
East Bay	L191	Pittsburg
East Bay	SP-3	Pittsburg
East Bay	SP-3	Pittsburg
East Bay	SP-3	Pittsburg
East Bay	SP-3	Pittsburg
Peninsula	L109	Redwood City
Peninsula	L132	Redwood City
Peninsula	L132	Redwood City
Peninsula	L132	Redwood City
Peninsula	L132	Redwood City
Peninsula	L147	Redwood City
North Bay	L210A	Solano County
North Bay	L210A	Solano County
North Bay	L210A	Solano County
Sac Valley	L123	Roseville
Sac Valley	L108	Sacramento
Sac Valley	L108	Sacramento
Sac Valley	L108	Sacramento

APPENDIX B, continued
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
Sac Valley	L108	Sacramento
Peninsula	L132	San Bruno
Peninsula	L109	San Bruno
Peninsula	L132	San Bruno
Peninsula	L132	San Bruno
Peninsula	L101	San Carlos
Peninsula	L101	San Carlos
Peninsula	L101	San Carlos
San Jose	L100	San Jose
Backbone	L300A	San Jose
Backbone	L300B	San Jose
Backbone	L300B	San Jose
Backbone	L300B	San Jose
San Jose	L100 / 0821-01	San Jose
East Bay	L153	San Leandro
East Bay	L153	San Leandro
North Bay	L210A	Suisun City
North Bay	L210A	Suisun City
North Bay	L210A	Suisun City
East Bay	L153	Union City
East Bay	L153	Union City

APPENDIX C
Scope of Study

PG&E will engage one or more third-party firms to conduct a comprehensive analysis of valve automation across PG&E's natural gas transmission system. This third-party analysis will include the following items, as well as review of (and refinements to) PG&E's preliminary assessment. This third-party analysis will deepen both PG&E's and the industry's understanding of whether and where ASV/RCV equipment should be used. Among other things, the third-party analysis will:

1. Research the industry's use of ASV/RCV equipment on gas transmission systems and identify best practices for design and operation, including the alternatives and merits of available ASV/RCV technology.
2. Survey major gas pipeline operators to collect information on the reasons operators use this equipment, their operating experience, the technology they employ, and the advantages and disadvantages the operators perceive to exist for the use of this technology in general, as well as the specific technology employed by the operator.
3. Evaluate distinctions in how ASV/RCV equipment is employed between FERC regulated pipeline systems, intrastate systems, gas utilities (transmission and distribution) and international pipeline systems.
4. Review PG&E's deployment of ASV/RCV equipment and manual isolation valves and the development of alternative deployment levels, and assess the pros and cons of various levels of additional deployment.

The following specific assessments will be performed:

- Evaluate and improve the pipeline segment selection criteria described above, developed as part of the preliminary assessment.
- Examine the reliability of ASV/RCV technology and the associated required maintenance activities and costs.
- Examine industry and federal government analyses of the merits of ASV/RCV equipment, including a review of state code changes which may have been adopted subsequent to the Texas Eastern Transmission Corporation (TETCO) pipeline explosion in New Jersey in 1994.

PG&E will also work with the third-party firm(s) on the following implementation issues related to ASV/RCV installations:

- Examine the impact of ASV/RCV expansion on PG&E's SCADA system.
    a) System capacity to provide data and control communications.
    b) Challenges related to installing SCADA at a host of remote sites.
    c) Required enhancements to Gas System Operations protocols and training.

APPENDIX C, continued
Scope of Study

- Examine the extent to which remote control will impact operating decisions, the protocols and risk assessment required to make those decisions, and the level of field verification required.
- Examine the feasibility of adding ASV/RCV to valves in a relatively short time period (*e.g.,* permit requirements or land rights for significant station modification or creation of new stations could require significant lead times).
- Examine the construction feasibility to determine obstacles that are particularly costly and time-consuming to resolve (*e.g.* valves could require replacement and/or relocation because they cannot be automated in their current location).
- Examine the extent to which the addition of automation equipment above ground poses a heightened security risk because the equipment is more visible or accessible to persons other than trained and authorized personnel.
- Assess the need for additional physical resources to replace, retrofit or install ASV or RCV valves.

PG&E has reviewed preliminarily the industry literature related to pipeline isolation and the use of ASV/RCV technology. These studies were used to conduct the preliminary assessment and develop this report. A third-party firm will undertake a more thorough review of this documentation and also investigate additional industry literature available on this subject.

1. Eiber, R.J. and McGehee, W.B., *Design Rationale for Valve Spacing, Structure Count, and Corridor Width*, PR249-9631, PRC International, May 30, 1997.
2. Shires, T.M. and Harrison, M.R., *Development of the B31.8 Code and Federal Pipeline Safety Regulations: Implication for Today's Natural Gas Pipeline System*, GRI-98/0367.1, December 1998.
3. Sparks, C.R. et al., *Remote and Automatic Main Line Valve Technology Assessment, Appendix, B*, GRI-95/0101, July 1995.
4. Sparks, C.R., Morrow, T.B. and Harrell, J.P., *Cost Benefit Study of Remote Controlled Main Line Valves*, GRI-98/0076, May 1998.
5. Texas Eastern Transmission Corp., *Natural Gas Pipeline Explosion and Fire*, NTSB/PAR-95/01.
6. Process Performance Improvement Consultants, (P-PIC), White Paper on Equivalent Safety for Alternative Valve Spacing, Draft April 18, 2005.
7. U.S. Department Of Transportation, Research and Special Programs Administration, Remotely Controlled Valves on Interstate Natural Gas Pipelines (Feasibility *Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996)*, September 1999.
8. Gas Research Institute 00/0189 "A Model for Sizing HCA's Associated with Natural Gas Pipelines", December 2001.

APPENDIX C, continued
Scope of Study

9. Eiber, R.J. and Kiefner and Associates, *Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing (To ASME Standards Technology, LLC)*, July 2010.

ATTACHMENT 3

ACCELERATED GAS SYSTEM SURVEY
INITIAL REPORT

In a letter from Paul Clanon to PG&E dated September 13, 2010 (Item 3) and in Ordering Paragraph 12 of Resolution L-403, the Commission directed PG&E to conduct an accelerated system survey of all natural gas transmission pipelines, giving priority to segments in Class 3 and Class 4 locations.

PG&E responded on September 20, 2010 and September 23, 2010, by committing to 1) complete an aerial accelerated system survey of its entire gas transmission system using laser detection technology; 2) complete a field evaluation wherever there are indications of possible leaks identified by aerial instruments; and 3) make repairs as necessary whenever leaks are found. PG&E also committed to complete accelerated system surveys using traditional methods for all Class 3 locations, Class 4 locations, and High Consequence Areas (HCAs) on its system. This initial report summarizes the results of these surveys.

As noted in our September 20, 2010 and September 23, 2010 letters, accelerated system surveys using traditional methods for Class 1 and Class 2 pipelines will be completed by December 15, 2010.

PG&E conducted an aerial survey of gas transmission lines and distribution feeder mains operating above 60 psig[6] using laser methane detection technology. This aerial survey provided a rapid safety survey of the entire transmission system. In the few areas where the aerial surveys were not possible, such as near wind turbine farms, PG&E performed an accelerated ground system survey. In addition to the aerial survey, PG&E also performed a traditional accelerated ground system survey of approximately 2,500 miles of Class 3 and Class 4 pipeline operating above 60 psig, and HCA transmission mains in Class 1 and Class 2 locations.[7]

Although the entire accelerated survey will not be completed until December 15, 2010, this initial report provides the Commission with the number of leaks identified during the

[6] PG&E has approximately 6,700 miles of gas pipe operating above 60 psig, all of which were covered by the aerial survey, except for the Peninsula lines, which were foot surveyed immediately after the accident. Approximately 5,700 miles of this pipe are considered a “transmission line” or a “transmission main” under U.S. Department of Transportation regulations. In addition, PG&E is the majority owner and operator for Standard Pacific Gas Line, Inc. (StanPac), which owns approximately 54 miles of natural gas transmission pipelines in California. The miles reported in this letter include an accelerated system survey of StanPac’s transmission system.

[7] PG&E has not yet been able to complete approximately 2.3 miles of its accelerated ground system survey. These 2.3 miles include areas where PG&E needs permission to access active military installations or where it needs to survey certain portions of the transmission pipeline under waterways.

first phase of the accelerated survey that required immediate repair (i.e., Grade 1 leaks).[8] As we have repeatedly stated, any issue, and certainly any gas leak, identified as a potential threat to public safety is always addressed right away. We do not delay or defer work that is necessary for public safety. In particular, any leak indication that is potentially hazardous is considered a Grade 1, and the employee or contractor who finds the leak remains at the location of the leak to ensure public safety until a crew arrives to take corrective action.

The aerial survey and the accelerated ground system survey in Class 3, Class 4 and HCA locations identified four (4) Grade 1 leaks on natural gas transmission mains, all in Class 3 HCA locations, which required immediate repair. These leak repairs would normally be reported in our Annual Report for calendar year 2010, Form PHMSA F 7100.2-1 due March 15, 2011, and our semi-annual reporting on our Integrity Management Program due February 28, 2011.

The details on these four Grade 1 leak repairs are as follows:

1. On September 19, 2010, a leak was found on a valve on Line 300B in the PG&E Hollister Yard in Hollister, within PG&E's fenced facility. The leak was repaired by tightening the cap/bolt.

2. On September 28, 2010, a below ground leak was found on Line 50 near Highway 99 in Gridley. The leak was repaired by replacing a section of pipe.

3. On October 4, 2010, an above ground leak was found on a flange on Line 210A at PG&E's Napa Meter Station in American Canyon, which is an enclosed facility. All bolts were tightened, which stopped the leakage.

4. On October 7, 2010, a leak was found on an underground valve on Line 0405-01 in Napa. The leak was repaired by greasing the valve.

In addition, PG&E also identified and immediately repaired 34 other Grade 1 leaks on distribution lines, distribution feeder mains operating above 60 psig, or other facilities appurtenant to transmission mains. All of those leaks have been repaired. Table 1, below, provides a listing of these other leaks, showing the location and corrective action.

As noted in our September 20, 2010 and September 23, 2010 letters, PG&E will complete the accelerated system survey of approximately 4,000 miles of Class 1 and Class 2 transmission pipelines by December 15, 2010. Any Grade 1 leaks identified in Class 1 or Class 2 locations will be repaired immediately. In addition, and as PG&E wrote in its September 23, 2010 letter, it will analyze all leak information gathered through both the accelerated aerial and ground system surveys to identify any trends and will review any recommendations with the Commission by January 31, 2011.

[8] Consistent with industry standards, all indications of potential leaks receive a grade. Grade 1 leaks are repaired immediately. Indications of potential leaks that do not require immediate repair are assessed and scheduled for any necessary corrective action.

TABLE 1
Ground and Aerial Accelerated System Survey
All Grade 1 Leak Repairs

City	Facility	Corrective Action
American Canyon	Flange	Tighten
Berkeley	Valve	Tighten
Chico	Service Tee	Tighten
Cupertino	Valve	Greased valve
Dublin	Regulator	Tighten
Firebaugh	Valve - Meter Station	Greased valve
Firebaugh	Valve - Meter Station	Greased valve
Fremont	Distribution	Welded Patch
Graton	Distribution	Installed Clamp over leak
Gridley	Main	Replaced pipe
Hilmar	Regulator	Replaced Regulator
Hollister	Valve	Tighten
Ione	Valve	Greased valve
Millbrae	Fitting on Main	Tighten
Modesto	Regulator	Replaced Regulator
Modesto	Regulator	Adjusted relief setting
Modesto	Regulator	Replaced Regulator
Morgan Hill	Main	Installed Sleeve over leak
Morgan Hill	Valve	Tighten
Napa	Valve	Greased valve
Oakland	Valve	Greased valve
Oakland	Valve & Regulator	Greased valve
Oakland	Distribution	Replaced Cap and Plug
Oakland	Regulator	Tighten
Oakland	Regulator	Replaced Regulator
Oakland	Valve	Greased valve
Oakland	Service Tee	Tighten
Oakland	Valve	Tighten
Palo Alto	Valve	Tighten
Patterson	Regulator	Tighten
Riverbank	Service Tee	Replaced cap
Rocklin	Distribution	Installed Electrofusion over Cap
Sacramento	Service Tee	Tighten
Sacramento	Service Tee	Tighten
Sacramento	Fitting on Main	Tighten
San Jose	Service Tee	Tighten
Stockton	Valve	Tighten
Stockton	Service Tee	Tighten

ATTACHMENT 4

CURTAILMENT PLANS

The letter from Paul Clanon to PG&E dated October 15, 2010 (Items 1, 2, and 3) directed PG&E to provide: (1) information on a gas curtailment plan in the event of the need to curtail gas deliveries in the San Francisco and Peninsula areas; (2) an electricity contingency plan in the event gas service is curtailed to the Potrero Power Plant; and (3) results of the detailed analysis PG&E was performing concerning the effects of the reduction of operating pressure and the possible strategies to reduce or avoid customer curtailments this winter.

BACKGROUND

PG&E uses two Commission-approved design criteria to set the capacity of its gas system, an Abnormal Peak Day (APD) and a Cold Winter Day (CWD). An APD occurs on average 1 in 90 years, and is designed to ensure continued service to all residential and small-commercial customers (core customers) while curtailing service to large-commercial and industrial customers (noncore customers). Curtailment is necessary to protect service to residential and small-commercial (core) customers and to maintain safe system operating pressures. In return for the risk of curtailment, noncore customers receive a discounted transmission rate. A CWD occurs on average 1 in 2 years, and is designed to ensure that no customers—core or noncore—are curtailed.

Depending on the mix of customers fed from a particular gas system, the system capacity is designed using either APD or CWD. APD and CWD represent minimum criteria; many portions of PG&E's gas system exceed these criteria and deliver greater reliability to customers.

GAS CURTAILMENT PLAN

Each year before the winter cold season, PG&E sends notices to its noncore customers reminding them of the potential for gas curtailments, their obligations under their tariff, and how they will be notified in the event curtailments are needed. Because of system changes caused by the Line 132 rupture, PG&E has developed a specific outreach program this year for customers in San Francisco and on the Peninsula and is undertaking several mitigation measures to reduce curtailments.

PG&E's outreach program is now underway for the 109 noncore gas customers on the San Francisco Peninsula and is aimed at ensuring they are fully prepared for any potential curtailments. Important elements of the communication plan are:

- All noncore customers have an assigned account manager.
- Beginning on October 14, 2010, PG&E initiated phone or face-to-face contacts with noncore customers in San Francisco and on the Peninsula to: 1) explain the potential for curtailments; 2) help those customers start planning how they would modify their operations if a curtailment is called; and 3), ensure that customers with alternative fuel capability have sufficient fuel on hand.

- Week of October 18, 2010 – PG&E began follow-up contacts with customers to support development of their plans for managing a curtailment.
- Late November 2010 – PG&E will provide formal notice of the potential for curtailment and levels of curtailment to all noncore customers on the San Francisco Peninsula. The allowed usage level will be based on the necessary percentage load reduction needed in each specific area to meet core gas customer reliability obligations under different weather scenarios. Also, customers will be able to receive automated cold weather messages from PG&E.

If curtailments are required, account managers will e-mail and fax (when a fax number is available) curtailment notifications in advance and make follow-up phone calls to customers who are to be curtailed. Curtailments will be from midnight to midnight.

Finally, there is a charge of $50 per decatherm, plus the Daily Citygate Index Price[9] if customers are not in compliance with required curtailments. PG&E relies primarily on the noncompliance charge to ensure compliance with curtailment orders. PG&E remotely monitors most noncore customer usage and will shut off a customer if that customer's noncompliance jeopardizes public safety or service to core customers.

ELECTRICITY CONTINGENCY PLAN

The Mirant Potrero Power Plant's Unit 3 is a natural gas-fired steam unit and represents 57% of the noncore load in San Francisco.[10] In the event PG&E curtails natural gas service to Potrero Power Plant Unit 3, the remaining electric transmission system along with the Potrero combustion turbines are adequate to meet winter peak electric demand in San Francisco without any need for electric service curtailment.

Currently, there are two electric transmission projects under construction: PG&E's recabling project, which is in its final construction phase and the Trans Bay Cable Project, which is in its final testing phase. Once fully operational, those projects would further increase system capability. In a letter dated January 12, 2010, the CAISO announced that Potrero Unit 3 can be retired "once the Trans Bay Cable Project demonstrated its reliability."

PG&E understands the Trans Bay Cable Project is undergoing its final testing this month. In fact, the CAISO has not been dispatching Potrero Unit 3 in October 2010 while the Trans Bay Cable is in its final testing mode.

PG&E's recabling project is in its final stage of construction. The first of the two cables was completed and has operated reliably since June 2010. The second cable is almost complete and is scheduled for operation by the end of November/beginning of December 2010.

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[9] The DCI is the PG&E Daily Citygate Index Price as published in Gas Daily, rounded up to the next whole dollar. If the price is not published on a given day, the previous price will apply.

[10] The other three operating units at Potrero Power Plant are diesel-fueled combustion turbine peaking units and would not be affected by a gas curtailment.

Although highly unlikely, an electricity curtailment is theoretically possible if (a) gas service is curtailed to the Potrero Unit 3, (b) both Trans Bay Cable and PG&E's recabling projects are not complete and not operating, and (c) more than one other electric transmission facility located in San Francisco became unavailable. PG&E has begun discussions with the CAISO to develop a plan for this unlikely event.

EFFECTS OF THE REDUCTION OF OPERATING PRESSURE AND POSSIBLE STRATEGIES TO REDUCE OR AVOID CUSTOMER CURTAILMENTS THIS WINTER

Strategy to Increase System Capacity and Reduce Curtailments

PG&E is implementing the following strategies and steps to increase the Peninsula local transmission system capacity to reduce the potential for customer curtailments:

- Making modifications to Milpitas Terminal to allow for safe, independent pressure set points on L-101, L-109, and L-132.
- Installing a new cross-tie and regulation between L-109 and L-132 upstream of the section of L-132 that is out of service (San Andreas cross-tie).
- Installing regulation at the existing Healy Station cross-tie between L-109 and L-132 just downstream of the section of L-132 that is out of service.
- Installing regulation at the existing Sierra Vista cross-tie to allow L-101 to support L-132.
- If needed during cold weather, manually operating the Edgewood cross-tie to allow L-101 to support L-132.
- Closing a main line valve on L-132 to reduce the demand and flow on L-132 and utilize the higher capacity of L-101 instead.
- Manually operating some distribution regulator stations during cold weather to ensure full supply pressure to distribution systems, thereby maximizing service reliability.

In addition, because the Potrero Power Plant's Unit 3 is 57% of the noncore load in San Francisco and Unit 3 can be curtailed without impacting electricity supply, PG&E has begun working with both the CAISO and Mirant to explore the potential to voluntarily curtail Unit 3 prior to other noncore customers. This would significantly reduce the likelihood of other noncore curtailments.

Results of Curtailment Analysis

PG&E has analyzed system capacity for Lines 101, 109, and 132 operating at various independent pressures on each of the three lines. PG&E has estimated noncore curtailment levels that would be needed to eliminate or reduce curtailments to core customers, consistent with our design criteria. These estimated curtailment levels assume completion of the system improvement strategy described above, and are estimates only; final curtailment plans will be developed once a determination of allowable operating pressures is complete. As mentioned above, PG&E's current approved design criteria consist of the Abnormal Peak Day (APD), in which all core customers are served and noncore customers are curtailed, and the Cold Winter Day (CWD), in which all customers are served—core and noncore. These represent minimum criteria; many portions of PG&E's gas system exceed these criteria and deliver greater reliability to noncore customers.

Estimated curtailments are provided below for three daily average temperatures in San Francisco:

- CWD, which occurs at 42 degrees Fahrenheit (F) daily average[11] temperature.
- Midpoint between CWD and APD, which is 37 degrees F daily average temperature.
- APD, which occurs at 32 degrees F daily average temperature.

System Capacity at 300 psig:

Lines 101, 109, and 132 currently are all operating at 300 psig. At these operating pressures, PG&E cannot meet either its CWD or APD design criteria. Noncore curtailments will be needed at temperatures warmer than a CWD. On an APD, 100% of all San Francisco and Peninsula noncore customers will need to be curtailed and some large core customers in the San Francisco area will need to be curtailed. At the midpoint temperature of 37 degrees daily average temperature, 100% of the noncore customers in the approximate area of San Francisco and South San Francisco will need to be curtailed.

These curtailment levels can be reduced if Line 101 and/or Line 109 are operated above 300 psig.

System Capacity at Pressures Above 300 psig:

PG&E analyzed curtailments at pressures in these lines of 337 psig and 375 psig, representing a 10% and 0% reduction from the pre-event pressure of 375 psig. At these increased pressures, noncore customers can be fully served under a CWD. At 37 degrees F daily average temperature, noncore curtailments could range from approximately 25% to 75% of San Francisco noncore demand, with lower curtailments at higher operating pressures. On an APD, noncore curtailments range from San Francisco south to other parts of the Peninsula. To avoid curtailment of core customers, L-101 and L-109 must both operate at pressures above 300 psig or L-101 must operate at a pressure at or near 375 psig.[12]

PG&E will develop a final curtailment plan when operating pressures are finalized and system capacity for winter is known.

[11] These temperature criteria are based on daily average temperature, not the lowest temperature reached during the day.

[12] For example, curtailment of some core customers occurs on an APD if L-101 is operated at 337 psig while L-109 and L-132 remain at 300 psig, in addition to curtailment of 100% of noncore demand along the entire Peninsula.

Pacific Gas and Electric Company

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February 11, 2011

Paul Clanon, Executive Director
California Public Utilities Commission
505 Van Ness
San Francisco, CA 94102-3298

Re: Long Range Gas Transmission Pipeline Planning Input
Top 100 Segments – 2007-2009

Dear Mr. Clanon:

In a letter dated September 17, 2010, you directed PG&E to "provide a list of PG&E's top 100 list of high priority pipeline projects, by segment, from 2007 to the present, that PG&E has identified as priority candidates for replacement or upgrade for reasons of public safety, including the current version of such list."

On September 20, 2010, PG&E provided a partial response to this request, which included the current list, based on 2009 data. On September 24, 2010, PG&E provided an update to the 2009 Top 100 gas transmission projects, which reflected changes such as more precise location information. PG&E also made the updated 2009 Top 100 available on its website.

As indicated in PG&E's September 20, 2010 response, the Top 100 list was not a list of projects that PG&E had identified as "priority candidates for replacement or upgrade for reasons of public safety." PG&E has a comprehensive gas transmission system integrity management program, which includes an inspection and monitoring program to help ensure the safety of its natural gas transmission pipeline system. Any issues identified as a threat to public safety are immediately addressed.

As described below, the Top 100 lists have been a component of PG&E's risk management program. As part of our efforts to enhance operations, PG&E has begun developing our Pipeline 2020 program, which is focused on modernizing our pipeline infrastructure, spurring development of next-generation pipeline inspection technologies, enhancing public safety awareness and emergency response planning, and developing industry-leading best practices, including state-of-the-art risk assessment techniques. Going forward, PG&E will use these new risk management techniques to guide its future work.

PG&E's Top 100 was an engineering planning tool within PG&E's integrity management program. Its primary function was to highlight segments for further engineering investigation, monitoring, or other follow-up, not for immediate repair or replacement. The Top 100 list was developed based on a program that first inventoried PG&E's entire transmission system, then evaluated data on each of the approximately 20,000 pipeline segments based on criteria such as the:

- Potential for third party damage like dig-ins from construction;
- Potential for corrosion;
- Potential for ground movement; and
- Physical design and characteristics of the pipe segment.

As part of its risk management evaluation and planning process, PG&E also considers the proximity of a pipeline segment to high density populations and environmentally-sensitive areas, as well as potential reliability impacts. Based on all of these factors, the segments that warrant further evaluation, monitoring, or other future action, were included each year on a Top 100 list to help in the development of future plans for work on our transmission pipelines

Attached to this letter is a combined list of the segments included on PG&E's 2007, 2008 and/or 2009 Top 100 lists for long-range evaluation and planning, along with updated notes on their status as of February 10, 2011. As shown in the status summary, 86 percent of pipeline segments that were listed only in 2007 or 2008 have been completed. For segments on the 2009 list, 56 percent have been completed and the rest are in various phases of action.

For those segments on the 2009 list that PG&E made available in September 2010, PG&E has retained the same map numbers for ease of reference, and has provided updated information where applicable. This consolidated 2007-2009 list will be made available on PG&E's website.

Please contact me should you have any questions.

Sincerely,

Brian K. Cherry
Vice President, Regulatory Relations

cc: Michael R. Peevey, President
Timothy A. Simon, Commissioner
Mike Florio, Commissioner
Catherine Sandoval, Commissioner
Julie Fitch, Energy Division
Richard Clark, Consumer Protection Safety Division
Julie Halligan, Consumer Protection Safety Division
Frank Lindh, General Counsel
Harvey Y. Morris, Legal Division
Patrick S. Berdge, Legal Division
Joe Como, Division of Ratepayer Advocates

February 11, 2011

Long Range Gas Transmission Pipeline Planning Input
Top 100 Segments – 2007, 2008 and Updated 2009

PG&E's top priority is to ensure the safety of our natural gas system. PG&E employs a comprehensive inspection and monitoring program to help achieve this goal. PG&E monitors system status in real time on a 24-hour basis, and regularly conducts leak surveys, patrols and maintenance of all of its natural gas pipelines. **Any issues identified as a threat to public safety are immediately addressed.**

PG&E also uses the data it collects daily on its gas transmission pipeline system to help plan and prioritize future work as part of its long-term risk management planning. As described below, PG&E's "Top 100" lists have been a component of this risk management program. As part of our efforts to enhance operations, PG&E has begun developing our Pipeline 2020 program, which is focused on modernizing our pipeline infrastructure, spurring development of next-generation pipeline inspection technologies, enhancing public safety awareness and emergency response planning, and developing industry-leading best practices, including state-of-the-art risk assessment techniques. Going forward, PG&E will use these new risk management techniques to guide its future work.

PG&E's risk management tools include a program that evaluates data on each of the approximately 20,000 pipeline segments within PG&E's natural gas transmission pipeline system based on the following criteria:

- the potential for third party damage like dig-ins from construction,
- the potential for corrosion,
- the potential for ground movement, and
- the physical design and characteristics of the pipe segment.

PG&E also considers the proximity of a pipeline segment to high-density populations and environmentally-sensitive areas, as well as potential reliability impacts.

Based on all of these factors, PG&E determines which segments warrant further evaluation, monitoring or other future action. Historically, these segments have been included each year on a Top 100 list to help guide the development of future plans. As conditions changed from year to year, PG&E reevaluated which segments were included on the list.

The Top 100 lists were used as engineering planning tools. Their primary function has been to highlight segments for further engineering investigation, monitoring or other long-term follow-up, but they do not determine which segments are designated for immediate repair or replacement.

PG&E has taken a range of appropriate actions depending on circumstances specific to each segment referenced on a Top 100 list. For example, if a segment was listed due to a high level of construction activity in the area, PG&E might have enhanced the surface markings of the pipeline and conducted additional outreach to help avoid accidental dig-ins. In other circumstances, where, for example, a segment was on the list due to its physical design and characteristics, PG&E may have increased its monitoring, patrolling or proposed to replace the segment.

The list below includes the segments on PG&E's 2007, 2008 and/or 2009 lists for long-range evaluation and planning, along with updated notes on their status as of February 10, 2011. As shown in the status summary below, 86 percent of pipeline segments that were listed only in 2007 or 2008 have been completed. For segments on the 2009 list, 56 percent have been completed and the rest are in various phases of action.

For ease of reference, PG&E has retained the same map numbers used in the 2009 list submitted in September 2010. This list also is available on PG&E's website at http://www.pge.com/planninginput/, along with maps to assist customers with specific questions about the location of PG&E's natural gas transmission lines.

Factor Key:

A pipeline segment is identified for further study and long-range planning based upon its risk for one or more of five unique factors:

- **Potential for Third-Party Damage:** Third-party damage is the number one risk to PG&E's pipeline system. Indications that a pipe segment may be at risk for third-party damage include third-party construction activity in the immediate area of the pipeline's location, whether or not the line segment has a history of third-party damage, the depth of cover over the pipeline, the pipe diameter, the degree of surface marking available for the location of the pipe segment, and local awareness of the potential for third-party damage in the immediate area of the pipeline's location. Some of the actions PG&E would take to reduce this risk factor include additional marking of the pipeline location (when possible), additional education in the immediate area for the 811 system to call before digging, and monitoring of construction activity and/or permits in the area around the pipeline.

- **Potential for Corrosion:** Factors include items such as the external coating design, the resistivity of the soil, and other ground-based factors which could reduce the thickness of the pipe wall. Some of the actions PG&E would take to reduce this risk include regular and ongoing monitoring (PG&E monitors both electronically and by physically checking its cathodic protection system every 2 months at over 6,000 locations in its natural gas transmission system), increasing or replacing the external protective coating of the pipe, or replacement of the pipe itself.

- **Potential for Ground Movement:** Factors include the proximity to seismically active areas, and the potential for soil erosion or landslides around the pipeline. Some of the actions PG&E would take to reduce this risk include increased monitoring, changing the soil material in which the pipe segment is buried, changing the alignment of the pipe segment, or burying the pipe segment at a greater depth beneath the ground level (for erosion prevention).

- **Physical Design and Characteristics:** Factors include items such as the age of pipe, the type of welding performed on the pipe, the fittings used in the pipeline, and the materials used to manufacture the pipe. Some of the actions PG&E would take to reduce this risk factor include replacement of the pipe or fittings in order to upgrade or improve the design or characteristics of the line segment or reducing pipeline pressure.

- **Overall:** A pipeline segment with an "Overall" factor is included on the list based upon its ranking in more than one of the factors outlined above but not based upon any single factor.

Rank:

PG&E's Top 100 list for a particular year was composed of the segments that ranked highest in each of the above five categories. It is important to note the "rank" that PG&E previously included in its 2009 Top 100 list and has also included in this combined 2007-2009 list is a relative ranking of these segments. PG&E has provided this "rank" as a means of comparing the total risk management score of a segment on a particular Top 100 list against the other segments on that list.

Status Key:

- **Monitoring:** PG&E is monitoring and reviewing these pipeline segments to see if they need to be addressed through a specific project.
- **Initiated:** PG&E has determined that the pipeline segment merits further study and analysis.
- **Engineering:** PG&E is defining the scope of the project and readying it for construction.
- **Construction:** PG&E has a project that is under construction.
- **Completed:** PG&E has determined that no further action is warranted on this segment due to the completion of an investigation that results in improved/updated pipeline information or the completion of an evaluation or construction project.

Regardless of status, every segment identified below remains within PG&E's comprehensive inspection and monitoring program discussed above. Any issues identified as a threat to public safety are immediately addressed.

Status Summary:

The following table provides a brief summary of the current status of the pipeline segments on PG&E's 2007, 2008 and 2009 Top 100 lists. Note that there are 78 pipeline segments on the 2007 and/or 2008 lists that do not also appear on the 2009 list. Also, note that the total number of individual segments on an annual list varies because some segments qualify for the list in more than one risk factor category (e.g., both for Potential for Ground Movement and Potential for Corrosion), reducing the total number of unique segments to less than 100. Conversely, in some years segments rank the same in a risk factor category, with these "ties" increasing the total number of segments to more than 100. For this reason, the 2007 list contains 85 segments and the 2008 list contains 110 segments. In total, there are 178 unique pipeline segments on the 2007-2009 Top 100 lists.

	Segments Only on 2007 and/or 2008 Lists		**Current 2009 Segments**	
Status as of February 2011	**Count**	**%**	**Count**	**%**
Completed	67	86%	56	56%
Construction or Engineering	8	10%	27	27%
Initiated or Monitoring	3	4%	17	17%
TOTALS	78	100%	100	100%

PG&E's goal is to be the best in class nationally on gas safety as we work to earn back the trust and confidence of our customers. Our current programs and the improvements that will come through our Pipeline 2020 program are key elements to achieving that goal.

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
1(a)	L103	Segment 117.1, Mile Points 11.00 – 11.42	San Benito	2007 2008 2009	Segment 117.1 is located in an unpopulated area on steep terrain which is particularly susceptible to ground motion. It will be replaced as part of a project to relocate 6 miles of pipe between Hwy 156 and Crazy Horse Rd. near San Juan Bautista due to exposure to the San Andreas fault line and through hillsides which are susceptible to landslides and soil erosion problems.	Potential for Ground Movement	Engineering	’07: 71 ’08: 94 ’09: 71
1(b)	L103	Segment 117.3, Mile Points 11.42 – 11.42	San Benito	2007 2008	The ground movement risk for segment 117.3 was reduced based on PG&E’s system-wide assessment of US Geological Survey data on the severity of erosion, including in the area in which this segment lies, causing this segment not to appear on the 2009 list. *(Notwithstanding its removal from the list, this segment of pipe is part of the project to relocate 6 miles of pipe between Hwy 156 and Crazy Horse Rd. near San Juan Bautista discussed at Map No. 1(a). Status: Engineering.)*	Potential for Ground Movement	Completed	’07: 77 ’08: 94
1(c)	L103	Segment 117.5, Mile Points 11.42 – 11.65	San Benito	2007 2008 2009	See description for Map No. 1(a).	Potential for Ground Movement	Engineering	’07: 72 ’08: 92 ’09: 72
2(a)	L107	Segment 127.1, Mile Points 14.00 – 14.82	Alameda	2008 2009	This section of Line 107 is located across the open hills from south Livermore to Arroyo del Valle. Based upon a recently completed engineering analysis, PG&E plans to convert this section from transmission pipeline to distribution feeder main.	Physical Design & Characteristics	Engineering	’08: 90 ’09: 74
2(b)	L107	Segment 127.5, Mile Points 14.82 – 15.12	Alameda	2008 2009	See description for Map No. 2(a).	Physical Design & Characteristics	Engineering	’08: 107 ’09: 89/ 90
2(c)	L107	Segment 127.57, Mile Points 15.13 – 15.36	Alameda	2009	See description for Map No. 2(a).	Physical Design & Characteristics	Engineering	’09: 89/ 90

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
2(d)	L107	Segment 127.6, Mile Points 15.36 – 15.36	Alameda	2008 2009	See description for Map No. 2(a).	Physical Design & Characteristics	Engineering	’08: 104 ’09:91
2(e)	L107	Segment 127.7, Mile Points 15.36 – 15.70	Alameda	2008 2009	See description for Map No. 2(a).	Physical Design & Characteristics	Engineering	’08: 100 ’09: 79/80
3(a)	L107	Segment 129, Mile Points 15.89 – 16.40	Alameda (Livermore)	2008 2009	This section of Line 107 is located across the open hills south of Livermore from Arroyo del Valle to the Vallecitos Valley. Based upon a recently completed engineering analysis, PG&E plans to convert this section from transmission pipeline to distribution feeder main..	Physical Design & Characteristics	Engineering	’08: 101 ’09: 79/80
3(b)	L107	Segment 131.5, Mile Points 17.11 – 18.00	Alameda	2009	See description for Map No. 3(a).	Potential for Ground Movement	Engineering	’09: 82
3(c)	L107	Segment 132.2, Mile Points 18.00 – 18.67	Alameda	2007 2009	See description for Map No. 3(a).	Potential for Ground Movement	Engineering	’07: 69 ’09: 73
4(a)	L107	Segment 139, Mile Points 21.07 – 22.29	Alameda	2007 2008 2009	This section of L107 is located across the open hills through the Vallecitos Valley to Calaveras Rd in Sunol. Based upon a recently completed engineering analysis, PG&E plans to convert this section from transmission pipeline to distribution feeder main. In addition, the external corrosion risk for segment 139 was reduced based on inspection of its coating condition, causing this segment not to appear on the 2009 list for potential corrosion (though the segment remained on the list for ground movement).	Potential for Ground Movement Potential for Corrosion (2007 and 2008)	Engineering	’07: 78 ’08: 93 ’09: 77

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
4(b)	L107	Segment 140, Mile Point 22.29	Alameda	2008	The external corrosion risk for segment 140 was reduced based on inspection of its coating condition, causing this segment not to appear on the 2009 list.	Potential for Corrosion	Completed	’08: 109
4(c)	L107	Segment 141, Mile Points 22.29 – 22.301	Alameda	2008	See description for Map No. 4(b).	Potential for Corrosion	Completed	’08: 108
4(d)	L107	Segment 141.8, Mile Points 22.34 – 22.79	Alameda	2008	See description for Map No. 4(b).	Potential for Corrosion	Completed	’08: 103
4(e)	L107	Segment 150, Mile Points 25.73 – 26.01	Alameda	2007 2008	The ground movement risk for this segment was reduced based on PG&E’s system-wide reassessment of US Geological Survey data on the severity of erosion, including in the area in which this segment lies, causing this segment not to appear on the 2009 list.	Potential for Ground Movement	Completed	’07: 81 ’08: 99
4(f)	L107	Segment 151, Mile Points 26.01 – 26.509	Alameda	2007 2008	See description for Map No. 4(e). *(Notwithstanding its removal from the list, PG&E plans to replace this segment in 2011 or 2012 in order to accommodate the work described on L131 below. See Map No. 14. Status: Engineering.)*	Potential for Ground Movement	Completed	’07: 61 ’08: 77
5(a)	L108	Segment 111, Mile Points 6.25 – 6.82	San Joaquin	2007	This segment consists of 2,897 feet of pipe near Airport Way and S Kasson Rd in Manteca. The external corrosion risk for this segment was reduced based on investigation of pipe strength and wall thickness, causing this segment not to appear on the 2008 and 2009 lists.	Potential for Corrosion	Completed	’07: 45
5(b)	L108	Segment 122.1, Mile Points 11.74 – 12.14	San Joaquin	2008	PG&E replaced this segment as part of a project that replaced 2.5 miles of pipe from Woodward Rd to West Ripon Rd (MP 11.74 to 14.15) due to the design materials used. Construction was completed in 2010.	Physical Design & Characteristics	Completed	’08: 81

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
5(c)	L108	Segment 122.3, Mile Points 12.14 – 12.16	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 82
5(d)	L108	Segment 123, Mile Points 12.16 – 12.47	San Joaquin	2007 2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’07: 64 ’08: 78
5(e)	L108	Segment 123.7, Mile Points 12.47 – 12.51	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 67
5(f)	L108	Segment 123.8, Mile Points 12.51 – 12.59	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 53
5(g)	L108	Segment 124, Mile Points 12.59 – 12.69	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 54
5(h)	L108	Segment 124.3, Mile Points 12.69 – 12.70	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 46
5(i)	L108	Segment 124.6, Mile Points 12.70 – 12.72	San Joaquin	2008 2009	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08:38 ’09: 43/44
5(j)	L108	Segment 125, Mile Points 12.72 – 12.76	San Joaquin	2008 2009	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	08:49 ’09: 43/44
5(k)	L108	Segment 125.05, Mile Points 12.76 – 12.79	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 68

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
5(l)	L108	Segment 125.1, Mile Points 12.79 – 13.19	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 83
5(m)	L108	Segment 125.3, Mile Points 13.19 – 13.21	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 84
5(n)	L108	Segment 126, Mile Points 13.21 – 13.71	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 85
5(o)	L108	Segment 126.3, Mile Points 13.71 – 13.73	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 86
5(p)	L108	Segment 127, Mile Points 13.73 – 14.13	San Joaquin	2007 2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’07: 65 ’07: 87
5(q)	L108	Segment 127.3, Mile Points 14.13 – 14.15	San Joaquin	2008	See description for Map No. 5(b).	Physical Design & Characteristics	Completed	’08: 106
6(a)	L108	Segment 140.9, Mile Points 37.04 – 37.14	San Joaquin	2008	PG&E plans to replace this segment as part of a project to enable an in-line inspection assessment to be performed. PG&E plans to commence construction in 2011.	Potential for Third Party Damage	Engineering	’08: 50
6(b)	L108	Segment 144, Mile Points 38.00 – 38.17	San Joaquin	2007	The external corrosion risk for segment 144 was reduced based on inspection of its coating condition, causing this segment not to appear on the 2008 and 2009 lists.	Potential for Corrosion	Completed	’07: 50
6(c)	L108	Segment 145, Mile Points 38.17 – 39.00	San Joaquin	2007 2008	The external corrosion risk for segment 145 was reduced based on inspection of its coating condition, causing this segment not to appear on the 2009 list.	Potential for Corrosion	Completed	’07: 51 ’08: 47

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
6(d)	L108	Segment 146.35, Mile Points 39.18 – 39.21	San Joaquin	2007 2008 2009	Replace 8,000 feet of pipe through the rural area near Armstrong Rd near Lodi due to the design materials used.	Physical Design & Characteristics Overall (2009)	Initiated	’07: 30 ’08: 29 ’09: 2/3/4
6(e)	L108	Segment 146.6, Mile Points 39.21 – 39.23	San Joaquin	2007 2008 2009	See description for Map No. 6(d).	Physical Design & Characteristics Overall (2009)	Initiated	’07: 31 ’08: 30 ’09: 2/3/4
6(f)	L108	Segment 147, Mile Points 39.23 – 39.47	San Joaquin	2007 2008 2009	See description for Map No. 6(d).	Physical Design & Characteristics Overall (2009)	Initiated	’07: 32 ’08: 31 ’09: 2/3/4
6(g)	L108	Segment 147.05, Mile Points 39.47–39.60 (33)	San Joaquin	2008	The external corrosion risk for segment 147.05 was reduced based on inspection of its coating condition, causing this segment not to appear on the 2009 list.	Potential for Corrosion	Completed	’08: 33
6(h)	L108	Segment 159, Mile Points 44.9 – 45.93	San Joaquin	2007	Replace 12,900 feet of pipe near W Peltier Rd, east of Lodi due to the design materials used.	Physical Design & Characteristics	Initiated	’07: 76
7(a)	L108	Segment 179.5, Mile Points 62.57 – 63.29	Sacramento (Elk Grove)	2008 2009	Replace 8,000 feet of pipe from Laguna Blvd to Dwight Road in Elk Grove due to the design materials used. Construction is currently planned to commence in 2011.	Physical Design & Characteristics	Engineering	’08: 34 ’09: 15
7(b)	L108	Segment 179.7, Mile Points 63.29 – 63.50	Sacramento (Elk Grove)	2007	See description for Map No. 7(a).	Physical Design & Characteristics	Engineering	’07: 60

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
8(a)	L109	Segment 137, Mile Points 15.00 – 15.38	Santa Clara (Palo Alto)	2007 2009	PG&E has adjusted the cathodic protection system to better protect these pipeline segments from corrosion. More recent analysis has shown marked improvement. No further action relative to the potential for external corrosion is contemplated at this time.	Potential for Corrosion	Completed	’07: 57 ’09: 56
8(b)	L109	Segment 137.19, Mile Points 15.38 – 15.65	Santa Clara (Palo Alto)	2009	See description for Map No. 8(a).	Potential for Corrosion	Completed	’07: 59 ’09: 60/61/62
8(c)	L109	Segment 137.2, Mile Points 16.80 – 16.93	Santa Clara (Palo Alto)	2007	See description for Map No. 8(a).	Potential for Corrosion	Completed	’07: 56
8(d)	L109	Segment 137.32, Mile Points 15.65 – 16.01	Santa Clara (Palo Alto)	2007 2009	See description for Map No. 8(a).	Potential for Corrosion	Completed	’09: 60/61/62
8(e)	L109	Segment 137.8, [1] Mile Points 16.19 – 16.33	Santa Clara (Palo Alto)	2007 2009	See description for Map No. 8(a).	Potential for Corrosion	Completed	’07: 58 ’09: 60/61/62
8(f)	L109	Segment 148, Mile Points 19.71 – 20.43	San Mateo (Palo Alto)	2008	See description for Map No. 8(a).	Potential for Corrosion	Completed	’08: 79
9(a)	L114	Segment 106, Mile Points 3.18 – 3.80	Solano/ Sacramento	2009	PG&E has conducted an engineering review of the potential for ground movement along this segment, crossing the Sacramento River and adjacent levees from Sherman Island north. This project includes L114-2, segment 101, discussed at Map No. 24(b). Based on this review, PG&E is planning to replace this crossing in 2013.	Potential for Ground Movement	Engineering	’09: 84/85

[1] This segment number is referred to as segment number 137.08 in the 2007 Top 100 list.

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
9(b)	L114	Segment 120, Mile Points 7.32 – 7.69	Sacramento/ Contra Costa	2009	PG&E has evaluated the potential of rerouting gas to allow the removal of 7,500 feet of three pipeline segments (L-114, segment 120; L114-1, segment 103, discussed at Map No. 24(a); and SP4Z, segment 112, discussed at Map No. 24(c)) crossing the San Joaquin River, underwater, near the Antioch Bridge due to the potential for ground movement. Based upon this evaluation, PG&E plans to remove these pipeline segments from service in 2011.	Potential for Ground Movement	Engineering	’09: 88/87
10	L114	Segment 153.2, Mile Points 28.00 – 28.87	Alameda	2009	Evaluate the potential replacement of 7,000 feet of pipe between Vasco Rd and Dalton Crossover, located on steep slopes from the North Livermore Valley to Vasco Rd due to the potential for ground movement.	Potential for Ground Movement	Initiated	’09: 69
11	L130	Segment 101, Mile Points 0.00 – 0.50	Solano/ Sacramento	2009	PG&E has completed an engineering analysis of 4,000 feet of pipe crossing the Sacramento River near the Rio Vista Bridge due to the potential for ground movement. This section of pipeline is located underwater. In conjunction with the Army Corp. of Engineer’s dredging project planned for 2013, PG&E plans to replace this crossing in 2013.	Potential for Ground Movement	Engineering	’09: 34
12(a)	L131	Segment 134.2, Mile Points 27.02 – 27.05	Alameda/ Contra Costa	2007	PG&E has evaluated the replacement of this section of L131, which is located over the steep hills north of Livermore, and plans to replace this segment. In addition, as part of PG&E’s transmission integrity management program, an in-line inspection assessment is planned for 2011.	Physical Design & Characteristics	Initiated	’07: 79

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
12(b)	L131	Segment 151, Mile Points 37.89 – 38.49	Alameda (Pleasanton)	2009	PG&E has evaluated the replacement of 4,990 feet of pipeline between Ruby Hills to Foleys Crossover in Pleasanton and Sunol due to the potential for ground movement, and plans to replace this segment. This pipeline is located on the steep slopes over the Pigeon Pass near Hwy 84 south of Livermore. In addition, as part of PG&E's transmission integrity management program, an in-line inspection is planned for 2011.	Potential for Ground Movement	Initiated	'09: 70
13	L131	Segment 157.2, Mile Points 42.16 – 42.35	Alameda (Sunol)	2007 2008 2009	Replace 1,350 feet of pipe at Calaveras Rd, Sunol due to the potential for ground movement. This segment of L131 is located on a steep hillside in the Sunol Valley immediately northeast of the Calaveras Fault and Road, just southeast of I-680. Construction was completed in October 2010.	Potential for Ground Movement	Completed	'07: 53 '08: 60 '09: 59
14(a)	L131	Segment 164, Mile Points 46.34 – 46.84	Alameda (Fremont)	2007 2008	The ground movement risk for segment 164 was reduced based on PG&E's system-wide reassessment of US Geological Survey data on the severity of erosion, including in the area in which this segment lies, causing this segment not to appear on the 2009 list. *(Notwithstanding its removal from the list, this segment is part of the project to remove 22,363 feet of pipe between the Vargas Rd and Irvington Station from transmission service discussed at Map No. 14(b)., Status: Engineering)*	Potential for Ground Movement	Completed	'07: 84 '08: 105

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
14(b)	L131	Segment 165, Mile Points 46.96 – 48.23	Alameda (Fremont)	2007 2008 2009	PG&E plans to remove 22,363 feet of pipe between the Vargas Rd and Irvington Station from transmission service, either by converting the pipe to a distribution main or into an outer, un-pressurized casing in which a new pipeline would be inserted. This section of L131 is located over the steep slopes from the Vargas Rd to Mission Blvd and through a 10-15 foot easement through central Fremont to I-880. Construction to permanently remove this from transmission service currently is planned for 2012. In addition, as part of PG&E's transmission integrity management program, an in-line inspection assessment is planned for 2011.	Potential for Ground Movement	Engineering	'07: 42 '08: 45 '09: 31
14(c)	L131	Segment 167.9, Mile Points 48.94 – 49.36	Alameda (Fremont)	2007 2008 2009	See description for Map No. 14(b).	Potential for Ground Movement Overall	Engineering	'07: 33 '08: 21 '09: 12
14(d)	L131	Segment 169, Mile Points 49.38 – 50.46	Alameda (Fremont)	2007 2008 2009	See description for Map No. 14(b).	Potential for Ground Movement	Engineering	'07: 37 '08: 44 '09: 22
15	L131	Segment 115, Mile Points 7.39 – 7.75	Contra Costa/ Sacramento	2009	PG&E plans to complete an engineering review of 2,066 feet of pipe located in the rural area near Sherman Island Levee Rd and the Antioch Bridge on Sherman Island in 2011. Based on this review, PG&E will determine whether any repair, replacement or other action is warranted.	Potential for Ground Movement	Initiated	'09: 75

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
16(a)	L132	Segment 106, Mile Points 1.27 – 1.34	Santa Clara (San Jose)	2007	The ground movement risk for segment 106 was reduced based on PG&E's system-wide reassessment of US Geological Survey data, including on the ground movement risk associated with this segment, causing this segment not to appear on the 2008 and 2009 lists. *(Notwithstanding its removal from the list, PG&E currently plans to replace this segment as part of a project to replace pipe due to the potential for ground movement. PG&E plans to commence construction in 2012. Status: Engineering.)*	Potential for Ground Movement Overall	Completed	'07: 24
16(b)	L132	Segment 106.7, Mile Points 1.35 – 1.87	Santa Clara (San Jose)	2007 2009	PG&E plans to replace this segment as part of a project to replace pipe due to the potential for ground movement. PG&E plans to commence construction in 2012.	Potential for Ground Movement	Engineering	'07: 34 '09: 26
16(c)	L132	Segment 112.7, Mile Points 3.05 – 3.067	Santa Clara (Santa Clara)	2007 2008	This segment is part of a project to replace pipe and install other facilities in order to internally inspect L132 through the urban areas between Milpitas and Crystal Springs reservoir. PG&E plans to commence construction in 2012 and to complete the in-line inspection assessments in 2013.	Overall	Engineering	'07: 19 '08: 11
16(d)	L132	Segment 113, Mile Points 3.067 – 3.3	Santa Clara (Santa Clara)	2007 2008	See description for Map No. 16(c).	Overall	Engineering	'07: 16 '08: 6
16(e)	L132	Segment 189, Mile Points 42.13- 43.55	San Mateo (South San Francisco)	2007	The replacement of this segment in South San Francisco had been planned for 2009. However, analysis by PG&E's pipeline engineers in early 2008 showed that the segment did not need replacement at that time. This updated analysis was subsequently confirmed by a March 2009 direct assessment of this segment. PG&E currently plans to replace this segment in 2012.	Overall	Engineering	'07: 21

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
17(a)	L138	Segment 116, Mile Points 22.70 – 23.40	Fresno (Riverdale)	2007 2008 2009	PG&E has completed an engineering review of 6,061 feet of pipe between Elkhorn Ave and Hwy 99 near Caruthers and Fresno for susceptibility to external corrosion. Based on cathodic protection survey results, the cathodic protection was determined to be satisfactory. Due to the presence of an outer pipe casing, which is required for railroad crossings but also increases the potential for corrosion, PG&E will continue to monitor these segments to determine whether future action is warranted.	Potential for Corrosion	Monitoring	’07: 36 ’08: 23 ’09: 49
17(b)	L138	Segment 129, Mile Points 38.08 – 38.42	Fresno (Easton)	2007	PG&E reassessed this segment from 2007 to 2008 due to the relocation of a nearby highway to a greater distance from segment 129, lowering the risk associated for this segment. This segment does not appear on the 2008 and 2009 lists.	Potential for Corrosion	Completed	’07: 46
17(c)	L138	Segment 130,[2] Mile Points 38.42 – 38.58	Fresno	2007 2008 2009	PG&E plans to replace this segment due to the design materials used. Construction is planned to commence in 2012.	Physical Design & Characteristics	Initiated	’07: 28 ’08: 35 ’09: 16
17(d)	L138	Segment 130.11,[3] Mile Points 38.59 – 38.59	Fresno	2007 2008 2009	See description for Map No. 17(c).	Physical Design & Characteristics	Initiated	’07: 28 ’08: 41 ’09: 20
17(e)	L138	Segment 145, Mile Points 48.29 – 48.64	Fresno (Fresno)	2009	The third-party damage risk assessment for this segment increased in 2009 due to previous damage on a pipeline near this location. A subsequent engineering investigation concluded that this segment is not exposed to any elevated third party damage risk, that surface marking of the segment is adequate and therefore that no further action is warranted.	Potential for Third Party Damage	Completed	’09: 18

[2] In 2007, a portion of segment 130 was identified as segment 129.6. In 2008, that portion was renamed as segment 130.

[3] In 2007, segment 130.11 was identified as segment 129.6. In 2008, it was renamed as segment 130.11.

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
18	L147	Segment 110.6, Mile Points 3.26 – 3.28	San Mateo (San Carlos)	2009	PG&E has completed an engineering review of the design materials of 105 feet of pipe near Brittan Ave and El Camino Real in San Carlos. Based upon the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Physical Design & Characteristics	Completed	’09:46
19(a)	L173	Segment 102.1, Mile Points 1.01 – 1.11	Placer (Roseville)	2007 2008 2009	An engineering review of this pipeline segment near Hwy 65 and Washington Blvd in Roseville has been conducted to assess risk for potential third-party damage. One third-party dig-in occurred nearby. Most of the area has been fully developed and the Blue Oaks overpass has been completed. The risk of third-party damage has been reduced and no further action is warranted.	Potential for Third Party Damage	Completed	’07: 41 ’08: 39 ’09: 38
19(b)	L173	Segment 102.6, Mile Points 1.45 – 1.50	Placer (Rocklin)	2008 2009	See description for Map No. 19(a).	Potential for Third Party Damage	Completed	’08: 42 ’09: 29
20(a)	L187	Segment 154.2, Mile Points 58.47 – 58.48	Monterey	2007	This segment is located in a rural area near Hwy 101, south of Salinas. It was assessed as having a potential for third-party damage. However, this assessment was revised in 2008 after PG&E conducted an additional public information program in the area and concluded that the risk of future third party damage was no longer as high, causing the segment not to appear on the 2008 or 2009 lists.	Potential for Third Party Damage	Completed	’07: 54
20(b)	L187	Segment 160, Mile Points 61.75 – 62.00	Monterey	2009	PG&E has completed an engineering review of 1,320 feet of pipe through the rural area near Hwy 101 across from Hartnell Rd near Salinas for the potential for damage by third parties. Based on this review, PG&E has performed notifications and installed additional line markers. No further action is warranted.	Potential for Third Party Damage	Completed	’09: 39

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
21(a)	L215	Segment 104, Mile Points 3.00 – 3.43	Stanislaus	2008 2009	PG&E conducted an engineering review of 3,310 feet of pipe between Hwy 33 in Patterson and Hwy 99 in Turlock based on corrosion monitoring data from segments 122.3 and 123. Three areas around the pipe were dug up to permit physical examinations of the pipe. Based on this review, no further action is warranted at this time.	Potential for Corrosion	Completed	’08: 75 ’09: 65
21(b)	L215	Segment 122.3, Mile Points 19.46 – 19.48	Stanislaus (Turlock)	2008 2009	See description for Map No. 21(a).	Potential for Corrosion	Completed	’08: 69 ’09: 63/64
21(c)	L215	Segment 123, Mile Points 19.56 – 19.74	Stanislaus (Turlock)	2008 2009	See description for Map No. 21(a).	Potential for Corrosion	Completed	’08: 66 ’09: 63/64
22(a)	0401-01	Segment 104, Mile Points 2.40 – 2.48	Marin (San Rafael)	2007 2009	PG&E has completed an engineering review of 1,887 feet of pipe through the suburban area along Lindaro St near Albert Park Ln in San Rafael. Based upon the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Overall	Completed	’07: 8 ’09: 99
22(b)	0401-01	Segment 104.8, Mile Points 2.48 – 2.76	Marin (San Rafael)	2008 2009	See description for Map No. 22(a).	Overall	Completed	’08: 4 ’09: 14
23	0407-01	Segment 104.8, Mile Points 1.83 – 1.88	Napa (Napa)	2009	PG&E replaced 247 feet of pipe near Foster Rd and Saint Francis Cir near Napa in 2009.	Physical Design & Characteristics	Completed	’09: 45

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
24(a)	L114-1	Segment 103, Mile Points 7.33 – 7.73	Solano/ Sacramento	2009	PG&E has evaluated the potential of rerouting gas to allow the removal of 7,500 feet of three pipeline segments (L114-1, segment 103; L-114, segment 120, discussed at Map No. 9(b); and SP4Z, segment 112, discussed at Map No. 24(c)) crossing the San Joaquin River, underwater, near the Antioch Bridge due to the potential for ground movement. Based upon this evaluation, PG&E plans to remove these pipeline segments from service in 2011.	Potential for Ground Movement	Engineering	’09: 87/88
24(b)	L114-2	Segment 101, Mile Points 3.18 – 3.80	Solano/ Sacramento	2009	PG&E has completed an engineering review of the potential for ground movement along this segment, crossing the Sacramento River and adjacent levees from Sherman Island north. This project includes L114, segment 106, discussed at Map No. 9(a). Based on this review, PG&E plans to replace this crossing in 2013.	Potential for Ground Movement	Engineering	’09: 84/85
24(c)	SP4Z	Segment 112, Mile Points 7.45 – 7.82	Solano/ Sacramento	2009	See description for Map No. 24(a).	Potential for Ground Movement	Engineering	’09: 83
25(a)	L118A	Segment 166.1, Mile Points 30.38 – 30.38	Madera	2008	The third-party damage risk for segment 166.1 was revised in 2009 after PG&E conducted an additional public information program in the area, causing the segment not to appear on the 2009 list. In addition, PG&E has confirmed that surface marking of the location is in place. Therefore, the risk of third-party damage has been reduced and no further action is warranted at this time.	Potential for Third Party Damage	Completed	’08: 96

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
25(b)	L118A	Segment 166.13, Mile Points 30.38 – 30.40	Madera	2007 2008 2009	An engineering review of this pipe segment near Avenue 18 ½ near Madera has been conducted to assess risk for potential third party damage. One third party dig-in occurred nearby. However, farming operations over the pipeline have since changed, and the pipeline now lies beneath a farm road. In addition, PG&E has confirmed that surface marking of the location is in place, and conducted an additional public information program in the area. Therefore, the risk of third-party damage has been reduced and no further action is warranted at this time.	Potential for Third Party Damage	Completed	’07: 75 ’08: 97 ’09: 76
25(c)	L118A	Segment 166.17, Mile Points 30.40 – 31.06	Madera	2007 2008 2009	See description for Map No. 25(b).	Potential for Third Party Damage	Completed	’07: 55 ’08: 63 ’09: 55
26	L119B	Segment 101, Mile Points 0.00 – 0.01	Sacramento (Sacramento)	2009	PG&E has completed an engineering review of the design materials of 1,437 feet of pipe near Lampasas Ave and Grove Ave in Sacramento. Based upon the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Physical Design & Characteristics	Completed	’09: 54
27(a)	1202-16	Segment 100, Mile Points 0.00 – 0.08	Fresno (Fresno)	2008 2009	The third-party risk on this line is elevated due in part to a third-party dig-in in the local area, which elevates the risk of nearby segments under PG&E’s integrity management program. A subsequent engineering investigation concluded that this segment is not exposed to any elevated third-party damage risk, that the segment lies beneath pavement or developed surfaces, and therefore that no further action is warranted.	Potential for Third Party Damage	Completed	’08: 22 ’09: 19
27(b)	1202-16	Segment 101, Mile Points 0.08 – 0.19	Fresno (Fresno)	2007 2008 2009	See description for Map No. 27(a).	Potential for Third Party Damage	Completed	’07: 38 ’08: 24 ’09: 23/24/25
27(c)	1202-16	Segment 101.1, Mile Points 0.19 – 0.27	Fresno (Fresno)	2008 2009	See description for Map No. 27(a).	Potential for Third Party Damage	Completed	’08: 25 ’09: 23/24/25

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
27(d)	1202-16	Segment 101.2, Mile Points 0.27 – 0.49	Fresno (Fresno)	2009	All segments (10,331 feet) of pipe along N Clovis Ave between E Shields Ave and E Ashlan Ave in Fresno and Clovis have been evaluated. Seven excavations were performed to examine the pipe for potential corrosion. Four of the sites examined showed no corrosion, and the remaining three showed a minimal amount of corrosion. Additional investigation in 2010 indicated that while this segment is not exposed to any elevated external corrosion risk, minor adjustments to the cathodic protection levels may be appropriate. PG&E will continue to monitor cathodic protection levels in 2011 and make adjustments when necessary.	Potential for Corrosion	Monitoring	’09: 27
27(e)	1202-16	Segment 102, Mile Points 0.49 – 1.03	Fresno (Fresno)	2008 2009	See description for Map No. 27(a).	Potential for Third Party Damage	Completed	’08: 26 ’09: 23/24/25
27(f)	1202-16	Segment 103, Mile Points 1.03 – 1.05	Fresno (Fresno)	2007 2008 2009	See description for Map No. 27(d).	Potential for Corrosion Overall	Monitoring	’07: 28 ’08: 17 ’09: 13
27(g)	1202-16	Segment 103.1, Mile Points 1.05 – 1.11	Fresno (Fresno)	2007 2009	See description for Map No. 27(d).	Potential for Corrosion	Monitoring	’07: 44 ’09: 35
27(h)	1202-16	Segment 103.3, Mile Points 1.11 – 1.20	Fresno (Fresno)	2007 2009	See description for Map No. 27(d).	Potential for Corrosion	Monitoring	’07: 39 ’09: 33
27(i)	1202-16	Segment 115, Mile Points 1.67 – 2.42	Fresno (Fresno)	2007 2008 2009	See description for Map No. 27(d).	Potential for Corrosion Overall	Monitoring	’07: 23 ’08: 15 ’09: 21
27(j)	1202-16	Segment 117, Mile Points 2.58 – 2.59	Fresno (Fresno)	2007 2008 2009	See description for Map No. 27(d).	Overall	Monitoring	’07: 20 ’08: 14 ’09: 97

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
28	L142S	Segment 114, Mile Points 7.30 – 8.70	Kern (Bakersfield)	2009	PG&E conducted an in-line inspection of 7,425 feet of pipe along S Union Ave between Watts Dr and 3rd St in Bakersfield due to the potential for external corrosion, and made all necessary repairs. As part of its monitoring effort, PG&E will conduct another in-line inspection of this line in September 2011.	Potential for Corrosion	Monitoring	’09: 28
29	1509-04	Segment 106, Mile Points 0.78 – 0.88	Sutter (Yuba City)	2009	PG&E has conducted an engineering review of 531 feet of pipe through the suburban area near N Walton Ave and Bridge St in Yuba City for the potential for damage by third parties. Two third-party dig-ins occurred nearby. However, development around the pipeline has since been completed; the pipeline is now under a roadway and a landscape easement. Therefore, the risk of third-party damage has been reduced.	Potential for Third Party Damage	Completed	’09: 47
30(a)	1509-05	Segment 120.1, Mile Points 6.23 – 6.28	Sutter (Yuba City)	2007 2008 2009	PG&E has conducted an engineering review of 1,371 feet of pipe through the suburban area near N Walton Ave and Bridge St in Yuba City for the potential for damage by third parties. Two third-party dig-ins occurred nearby. However, development around the pipeline has since been completed; the pipeline is now under a roadway and a landscape easement. Therefore, the risk of third-party damage has been reduced.	Potential for Third Party Damage	Completed	’07: 49 ’08: 61 ’09: 36/37
30(b)	1509-05	Segment 120.2, Mile Points 6.28 – 6.29	Sutter (Yuba City)	2007 2008 2009	See description for Map No. 30(a).	Potential for Third Party Damage	Completed	’07: 52 ’08: 65 ’09: 48
30(c)	1509-05	Segment 120.3, Mile Points 6.29 – 6.33	Sutter (Yuba City)	2007 2008 2009	See description for Map No. 30(a).	Potential for Third Party Damage	Completed	’07: 40 ’08: 62 ’09: 36/37
30(d)	1509-05	Segment 121, Mile Points 6.33 – 6.49	Sutter (Yuba City)	2007 2009	See description for Map No. 30(a).	Potential for Third Party Damage	Completed	’07: 43 ’09: 40

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
31	1815-15	Segment 130.3, Mile Points 2.04 – 2.13	Monterey	2007 2008 2009	PG&E plans to complete an engineering review of 437 feet of pipe through the suburban area near Hwy 68 and Aguajito Rd near Monterey by June 2011. Based on this review, PG&E will determine whether any repair, replacement or action is warranted. In addition, as part of PG&E's transmission integrity management program, an external corrosion direct assessment is planned for 2011.	Overall	Initiated	'07: 5 '08: 9 '09: 5
32(a)	L195A 3-1	Segment 100, Mile Points 0.00 – 0.00	Sacramento (Isleton)	2009	In 2010 PG&E isolated this segment (i.e., capped the pipe at both ends to prevent gas supply from reaching this segment) to mitigate the risk of damage by third-parties. No further action is warranted.	Potential for Third Party Damage	Completed	'09: 57/58
32(b)	L195A 3-1	Segment 102, Mile Points 0.00 – 0.04	Sacramento (Isleton)	2009	See description for Map 32(a).	Potential for Third Party Damage	Completed	'09: 57/58
32(c)	L195A 3-1	Segment 102.1, Mile Points 0.04 – 0.17	Sacramento (Isleton)	2009	See description for Map 32(a).	Potential for Third Party Damage	Completed	'09: 42
33(a)	L210A	Segment 116, Mile Points 14.15 – 16.00	Solano (Fairfield)	2008	The third-party damage risk assessment for this segment increased in 2008 due to previous damage on a pipeline near this location. A subsequent engineering investigation concluded that this segment is not exposed to any elevated third party damage risk, that surface marking of the segment is adequate and therefore that no further action is warranted. *(Notwithstanding its removal from the list, PG&E plans to perform an internal line inspection on this segment in 2011. See Map No. 33b. Status: Initiated.)*	Potential for Third Party Damage	Completed	'08: 37

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
33(b)	L210A	Segment 117.5, Mile Points 18.73 – 18.86	Solano (Fairfield)	2008 2009	Construction has been completed to install equipment and modify the pipeline to allow an in-line inspection to be conducted. An in-line inspection assessment is scheduled for 2011.	Overall Potential for Ground Movement	Completed (Construction) Initiated (In-Line Insp.)	’08: 20 ’09: 1
33(c)	L210A	Segment 117.6, Mile Points 18.86 – 18.96	Solano (Fairfield)	2007 2008	See description for Map No. 33(a).	Potential for Third Party Damage	Completed	’07: 47 ’08: 51
33(d)	L210A	Segment 118.1, Mile Points 18.97 – 19.47	Solano (Fairfield)	2007 2008 2009	See description for Map No. 33(b).	Overall	Completed (Construction) Initiated (In-Line Insp.)	’07: 4 ’08: 1 ’09: 10
34(a)	L300A	Segment 240.3, Mile Points 277.85 – 278.01	Kern (Bakersfield)	2008 2009	PG&E has conducted an engineering review of this pipeline segment located in the suburban area between Buena Vista Rd and Pacheco Rd in Bakersfield for the potential for damage by third parties. This segment was relocated due to the widening of the road and no further action is warranted.	Potential for Third Party Damage	Completed	’08: 36 ’09: 30
34(b)	L300A	Segment 240.61, Mile Points 278.01 – 278.10	Kern (Bakersfield)	2009	See description for Map No. 34(a).	Potential for Third Party Damage	Completed	’09: 32

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
35(a)	L300B	Segment 193, Mile Points 161.02 – 161.07	San Bernardino	2009	PG&E has completed an engineering review of the design materials of 843 feet of pipe through the rural area. Based on this review, PG&E determined that no repair, replacement or other action was warranted. In addition, as part of PG&E's transmission integrity management program, an external corrosion direct assessment is planned for 2011.	Physical Design & Characteristics	Completed	'09: 67/68
35(b)	L300B	Segment 194, Mile Points 161.43 – 161.48	San Bernardino	2009	See description for Map No. 35(a)	Physical Design & Characteristics	Completed	'09: 67/68
36(a)	L316A	Segment 111, Mile Points 0.61 – 0.78	Contra Costa	2009	PG&E has completed an engineering review of 7,777 feet of pipe between Jersey Island Rd on Jersey Island and Taylor Rd on Bethel Island. Based on cathodic protection survey results, the cathodic protection was determined to be adequate. No further assessment or work is planned at this time.	Potential for Corrosion	Completed	'09: 92
36(b)	L316A	Segment 112, Mile Points 0.79 – 1.00	Contra Costa	2009	See description for Map No. 36(a).	Potential for Corrosion	Completed	'09: 94
36(c)	L316A	Segment 113, Mile Points 1.00 – 1.09	Contra Costa	2009	See description for Map No. 36(a).	Potential for Corrosion	Completed	'09: 86
36(d)	L316A	Segment 115, Mile Points 1.19 – 1.23	Contra Costa (Jersey Is)	2009	See description for Map No. 36(a).	Potential for Corrosion	Completed	'09: 81
36(e)	L316A	Segment 116, Mile Points 1.23 – 2.05	Contra Costa (Jersey Is)	2009	See description for Map No. 36(a).	Potential for Corrosion	Completed	'09: 78

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
36(f)	L316A	Segment 117, Mile Points 2.05 – 2.31	Contra Costa (Bethel Is)	2009	See description for Map No. 36(a).	Potential for Corrosion	Completed	’09: 93
37	DCUST 1416	Segment 100, Mile Points 0.00 – 0.01	Humboldt (Ferndale)	2007 2008 2009	PG&E has conducted an engineering review of 28 feet of pipe through the rural area near Fernbridge Dr and Depot St near Ferndale. Based upon the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Potential for Ground Movement Overall	Completed	’07: 14 ’08: 2 ’09: 6
38	DFDS 3543	Segment 100, Mile Points 10.91 – 10.91	Marin (Novato)	2007 2009	PG&E has completed an engineering review of 3 feet of pipe near Redwood Blvd and Atherton Ave in Novato. Based the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Overall	Completed	’07: 18 ’09: 11
39(a)	DRIP 7966	Mile Points 0.00 – 0.00	Santa Clara (San Jose)	2007 2009	PG&E has completed an engineering review of the potential for ground movement along 10 feet of pipe near Milpitas-Alviso Rd and Ranch Dr in San Jose. Based upon the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Potential for Ground Movement	Completed	’09: 7 ’07: 7
39(b)	DRIP 7970	Segment 651, Mile Points 0.00 – 0.00	Santa Clara (San Jose)	2007	PG&E completed an engineering review of the physical design and characteristics of this 10 foot pipeline segment located near Yerba Buena Rd in San Jose. Based upon the results of this review, PG&E determined that no repair, replacement or other action was warranted.	Physical Design & Characteristics Overall	Completed	’07: 7
40	DRIP 7971	Segment 651, Mile Points 0.00 – 0.00	Santa Clara (Milpitas)	2007 2009	PG&E has completed an engineering review of the potential for ground movement along 10 feet of pipe near Milpitas-Alviso Rd and Ranch Dr in Milpitas. Based upon the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Potential for Ground Movement	Completed	’07: 1 ’09: 17

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
41(a)	SP3	Segment 160.3, Mile Points 198.49 – 198.49	Contra Costa (San Pablo)	2008 2009	Replace approximately 300 feet of pipe inside PG&E's San Pablo Station and crossing Rumrill Blvd in San Pablo due to the potential for ground movement. Construction is planned for 2012. The small section of pipeline that includes this segment has been isolated (i.e., closed valves at both ends to prevent gas supply from reaching this segment) from the rest of PG&E's system, reducing its overall risk.	Potential for Ground Movement	Engineering	'08: 48 '09: 41
41(b)	SP3	Segment 160.36, Mile Points 198.49 – 198.49	Contra Costa (San Pablo)	2008 2009	See description for Map No. 41(a).	Potential for Ground Movement	Engineering	'08: 56 '09: 50/51/52/ 53
41(c)	SP3	Segment 160.4, Mile Points 198.49 – 198.49	Contra Costa (San Pablo)	2008 2009	See description for Map No. 41(a).	Potential for Ground Movement	Engineering	'08: 57 '09: 50/51/52/ 53
41(d)	SP3	Segment 160.5, Mile Points 198.49 – 198.52	Contra Costa (San Pablo)	2008 2009	See description for Map No. 41(a).	Potential for Ground Movement	Engineering	'08: 58 '09: 50/51/52/ 53
41(e)	SP3	Segment 160.6, Mile Points 198.52 – 198.55	Contra Costa (San Pablo)	2008 2009	See description for Map No. 41(a).	Potential for Ground Movement	Engineering	'08: 59 '09: 50/51/52/ 53
42(a)	X6337	Segment 100, Mile Points 10.84 – 10.84	Marin (Novato)	2007 2009	PG&E has completed an engineering review of two 30-foot segments of pipe near Redwood Blvd and Atherton Ave in Novato. Based upon the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Physical Design & Characteristics Overall	Completed	'07: 12 '09: 8/9
42(b)	X6337	Segment 101, Mile Points 10.84 – 10.84	Marin (Novato)	2007 2009	See description for Map No. 42(a).	Physical Design & Characteristics Overall	Completed	'07: 13 '09: 8/9

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
43	X6526	Segment 505, Mile Points 0.24 – 0.24	Kings (Kettleman City)	2009	PG&E has conducted an engineering review of the design materials of about 9 feet of pipe through the rural area south of Kettleman City. Based upon the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Physical Design & Characteristics	Completed	’09: 66
44	DREG 4197	Segment 801, Mile Points 0.00 – 0.00	San Mateo (Palo Alto)	2007 2008 2009	PG&E has completed an engineering review of 18 feet of pipe near Dumbarton Ave. and Donahoe St. in East Palo Alto. Based upon the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Overall	Completed	’07: 22 ’08: 19 ’09: 95
45(a)	7221-15	Segment 101, Mile Points 0.04 – 1.31	Stanislaus (Modesto)	2007 2008 2009	PG&E has completed an engineering review of 6,709 feet of pipe along Dale Rd between Standiford Ave and Bangs Ave. Based on this review, PG&E determined that no repair, replacement or other action was warranted.	Overall Physical Design & Characteristics	Completed	’07: 3 ’08: 40 ’09: 96
45(b)	7221-15	Segment 102.3, Mile Points 1.44-1.51	Stanislaus (Modesto)	2007 2008	See description for Map No. 45(a).	Overall	Completed	’07: 17 ’08: 32
46	DREG 3875	Segment 101, Mile Points 0.00 – 0.00	Marin (Novato)	2009	PG&E has completed an engineering review of 285 feet of pipe near Redwood Blvd and Atherton Ave in Novato. Based upon the results of this review, PG&E has determined that no repair, replacement or other action is warranted.	Overall	Completed	’09: 98
47	STUB 7912	Segment 551, Mile Points 0.04 – 0.04	Stanislaus (Modesto)	2007 2009	PG&E has completed an engineering review of 2 feet of pipe near Dale Rd and Bangs Ave in Modesto as part of the effort described at Map No. 45(a). Based on this review, PG&E determined that no repair, replacement or other action was warranted.	Overall	Completed	’07: 6 ’09: 100

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
48(a)	L150	Segment 118.3, Mile Points 17.51 – 17.89	Yolo (Davis)	2008	PG&E plans to remove this segment of pipe near Olive Dr. and Richards Blvd. in Davis from transmission service by converting the pipe to a distribution main or retiring it. Construction to permanently remove this segment from transmission service currently is planned for 2011.	Overall	Engineering	’08: 12
48(b)	L150	Segment 118.8, Mile Points 18.08 – 18.09	Yolo (Davis)	2007 2008	See description for Map No. 48(a).	Overall	Engineering	’07: 25 ’08: 10
48(c)	L150	Segment 119, Mile Points 18.09 – 18.0913	Yolo (Davis)	2007 2008	See description for Map No. 48(a).	Overall	Engineering	’07: 15 ’08:3
49	L220	Segment 134.2, Mile Points 22.14 – 22.17	Yolo (Davis)	2007	This segment consists of 154 feet of pipe near Olive Dr in Davis. This segment was assigned a lower risk value in 2008 based upon improved external corrosion information, causing it not to appear on the 2008 list. The risk value of the segment was lowered further in 2009 based upon improved geophysical information. No repair, replacement or other action is warranted.	Overall	Completed	’07: 27
50	L314	Segment 127, Mile Points 28.11 – 28.83	San Bernardino (Victorville)	2008	PG&E inspected the coating condition of this segment (4,446 feet of pipe through the rural area along N D St and Hwy 15 in Victorville) in 2008 and reduced the external corrosion risk as a result of this inspection, causing it not to appear on the 2009 list.	Potential for Corrosion	Completed	’08: 74
51	L402	Segment 130, Mile Points 24.00 – 25.00	Shasta	2008	The third-party damage risk assessment for this segment increased in 2008 due to previous third-party damage to this segment. A subsequent engineering investigation concluded that this segment is not exposed to any elevated third party damage risk, that surface marking of the segment is adequate and therefore that no further action is warranted.	Potential for Third Party Damage	Completed	’08: 43

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
52	0126-01	Segment 101, Mile Points 0.00 – 0.1409	Contra Costa (Richmond)	2007	This segment consists of 745 feet of pipe near W Gertude and McKosken Rd in Richmond. Its potential for corrosion was reduced after PG&E determined that the segment lay in soil which was less corrosive than previously assessed and did not have an outer pipe casing. This reassessment caused the segment not to appear on the 2008 and 2009 lists.	Potential for Corrosion	Completed	’07: 73
53	L057A	Segment 103, Mile Points 7.48 – 9.04	Contra Costa (Brentwood)	2007	PG&E conducted a survey of this pipeline segment near Fallman Rd in Brentwood to assess its potential susceptibility to external corrosion. Based upon the information obtained from that survey regarding the adequacy of the cathodic protection system and the pipeline coating condition, PG&E determined that no repair or replacement of this segment was warranted.	Potential for Corrosion	Completed	’07: 80
54	0603-01	Segment 101.2, Mile Points 0.005 – 0.20	Solano (Fairfield)	2008	PG&E conducted an investigation of this segment of pipe through the suburban area along Illinois St. in Fairfield. Based upon the results of this investigation, PG&E determined that no repair, replacement or other action was warranted.	Overall	Completed	’08: 16
55	0646-01	Segment 115.3, Mile Points 10.25 – 10.31	Yolo	2008	This segment consists of 302 feet of pipe in a rural area along County Rd 97A and Hwy 5 near Woodland. PG&E improved the cathodic protection of this segment, reducing the external corrosion risk and causing it not to appear on the 2009 list.	Potential for Corrosion	Completed	’08: 98
56	L119A	Segment 109.7, Mile Points 8.57 – 8.58	Yolo	2007 2008	The third-party damage risk assessment for this segment increased in 2007 due to previous third-party damage to this segment. A subsequent engineering investigation concluded that this segment is not exposed to any elevated third party damage risk, that surface marking of the segment is adequate and therefore that no further action is warranted.	Potential for Third Party Damage	Completed	’07: 62 ’08: 72
57(a)	L124B	Segment 123.5, Mile Points 20.04 – 20.10	Yuba (Olivehurst)	2008	The external corrosion risk for this segment was reduced based on an inspection of its coating condition, causing this segment not to appear on the 2009 list.	Potential for Corrosion	Completed	’08: 76

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
57(b)	L124B	Segment 125, Mile Points 20.35 – 20.55	Yuba (Marysville)	2008	See description for Map No. 57(a).	Potential for Corrosion	Completed	’08: 89
58(a)	L126B	Segment 103, Mile Points 1.43 – 2.16	Humboldt (Eureka)	2007 2008	The fault crossing in this area (16,197 feet of pipe near New Tompkins Hill Rd. in Eureka) was assigned a lower risk value in 2009 based upon improved geophysical information, causing it not to appear on the 2009 list.	Potential for Ground Movement	Completed	’07: 85 ’08: 110
58(b)	L126B	Segment 104, Mile Points 2.17 – 2.73	Humboldt (Eureka)	2007 2008	See description for Map No. 58(a).	Potential for Ground Movement	Completed	’07: 83 ’08: 102
58(c)	L126B	Segment 105, Mile Points 2.73 – 4.00	Humboldt (Eureka)	2007 2008	See description for Map No. 58(a). The external corrosion risk for this segment was reduced based on inspection of its coating condition, causing this segment not to appear on the 2008 and 2009 lists for potential for corrosion.	Potential for Ground Movement Potential for Corrosion (2007)	Completed	’07: 48 ’08: 55
58(d)	L126B	Segment 106, Mile Points 4.00 – 4.69	Humboldt (Eureka)	2007 2008	See description for Map No. 58(c).	Potential for Ground Movement Potential for Corrosion (2007)	Completed	’07: 74 ’08: 95
58(e)	L126B	Segment 106.85, Mile Points 4.70 – 4.7183	Humboldt (Eureka)	2007	The external corrosion risk for segment 106.85 was reduced based on inspection of its coating condition, causing this segment not to appear on the 2008 and 2009 lists.	Potential for Corrosion	Completed	’07: 82
58(f)	L126B	Segment 107.6, Mile Points 5.093 – 5.13	Humboldt (Eureka)	2007 2008	See description for Map No. 58(a).	Potential for Ground Movement	Completed	’07: 35 ’08: 27

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
59	1301-01	Segment 124, Mile Point 0.00	Sonoma (Petaluma)	2008	The third-party damage risk assessment for this segment increased in 2008 due to previous third-party damage to this segment. This segment is now located inside a fenced PG&E station. A subsequent engineering investigation of this area confirmed that this segment is not exposed to any elevated third party damage risk and therefore that no further action was warranted.	Overall	Completed	’08: 18
60(a)	L138C	Segment 105.3, Mile Points 44.72 – 44.81	Fresno (Fresno)	2008	PG&E conducted a survey of this pipeline running along North and Cedar in Fresno for susceptibility to external corrosion. Based upon the information obtained from that survey regarding the adequacy of the cathodic protection system, PG&E determined that no repair, replacement or other action was warranted.	Potential for Corrosion	Completed	’08: 52
60(b)	L138C	Segment 105.6, Mile Points 44.81 – 44.90	Fresno (Fresno)	2008	See description for Map No. 60(a).	Potential for Corrosion	Completed	’08: 64
61	L142S	Segment 116.3, Mile Points 8.9927 – 9.01	Kern (Bakersfield)	2007	This segment consists of 65 feet of pipe along V St north of Brundage Ln, in Bakersfield. The external corrosion risk for this segment was reduced based on inspection of its coating condition, causing the segment not to appear on the 2008 and 2009 lists.	Potential for Corrosion	Completed	’07: 68
62	L162A	Segment 113.2, Mile Points 7.07 – 7.22	San Joaquin (Tracy)	2007 2008	This segment consists of 814 feet of pipe near Grant Line and Macarthur in Tracy. In 2009, PG&E updated its system-wide risk assessment of certain properties relative to the external corrosion risk which reduced the relative risk for this segment, and the risk due to third party damage for this segment in particular was reduced due to an additional public information program. This segment does not appear on the 2009 list.	Overall	Completed	’07:26 ’08: 7

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
63	L177A	Segment 215.1 Mile Points 170.57 – 171.00	Humboldt (Fortuna)	2008	The fault crossing in this area (2,251 feet of pipe near Hwy 36 and Hwy 100 near Fortuna) was assigned a lower risk value in 2009 based upon improved geophysical information, causing it not to appear on the 2009 list.	Potential for Ground Movement	Completed	’08: 28
64(a)	L181B	Segment 104.6, Mile Points 2.17 – 2.18	Monterey	2007 2008	The third-party damage risk assessment for this segment increased in 2007 due to previous third-party damage to this segment. A subsequent engineering investigation concluded that this segment is not exposed to any elevated third party damage risk, that surface marking of the segment is adequate and therefore that no further action is warranted.	Potential for Third Party Damage	Completed	’07: 67 ’08: 88
64 (b)	L181B	Segment 104.8, Mile Points 2.18 – 2.21	Monterey	2007 2008	See description for Map No. 64(a).	Potential for Third Party Damage	Completed	’07: 66 ’08: 80
65	L197B	Segment 105, Mile Points 4.14 – 4.40	San Joaquin	2008	The third-party damage risk assessment for this segment increased in 2008 due to previous damage on a pipeline near this location. A subsequent engineering investigation concluded that this segment is not exposed to any elevated third party damage risk, that surface marking of the segment is adequate and therefore that no further action is warranted.	Potential for Third Party Damage Overall	Completed	’08: 5
66	L300A	Segment 369.051, Mile Points 473.09 – 473.99	Santa Clara (San Martin)	2008	This segment consists of 4,780 feet of pipe near Foothill Rd. and Maple Rd. in San Martin. The risk of third-party damage was reduced based on analysis of the depth of cover over this segment, which found the cover to be adequate.	Potential for Third Party Damage	Completed	’08: 73
67(a)	L300B	Segment 336.0, Mile Points 362.7061 – 362.7087	Fresno	2007	This segment is located near Gale Ave. and S. Butte Rd. near Coalinga. In 2007, PG&E conducted a survey of these pipeline segments to assess their potential susceptibility to external corrosion. Based upon the information obtained from that survey regarding the functioning of the cathodic protection system and the pipeline coating condition, PG&E determined that no repair or replacement of these segments was warranted.	Potential for Corrosion	Completed	’07: 70

Map No.	Pipeline	Segment	Location: County (City)	Year On List	Description as of February 2011	Factor	Status as of February 2011	Rank
67(b)	L300B	Segment 336.5, Mile Points 362.8785 – 362.883	Fresno	2007	See description for Map No. 67(a).	Potential for Corrosion	Completed	’07: 63
67(c)	L300B	Segment 336.9, Mile Points 362.89 – 362.90	Fresno	2008	This segment consists of 69 feet of pipe near Gale Ave. and S. Butte Rd near Coalinga. In 2007, PG&E conducted a survey of pipeline segments in this area to assess their potential susceptibility to external corrosion. Based upon the information obtained from that survey regarding the functioning of the cathodic protection system and the pipeline coating condition, PG&E determined that no repair or replacement of these segments was warranted.	Potential for Corrosion	Completed	’08: 70
68	L302W	Segment 107.5, Mile Points 5.01 – 5.13	Yolo	2008	This segment consists of 594 feet of pipe near Hwy 5 and Road 2A, north of Woodland. PG&E plans to complete an assessment of an adjacent segment for susceptibility to external corrosion in 2011. Based on this assessment, PG&E will determine whether any repair, replacement, or other action is warranted.	Potential for Corrosion	Initiated	’08: 71
69	DREG 4102	Segment 801, Mile Points 0.00 – 0.02	Yolo (Davis)	2007 2008	PG&E conducted an engineering review of this pipeline segment located near 2nd St in Davis. Based upon the results of this review, PG&E determined that no repair, replacement or other action was warranted.	Overall Physical Design & Characteristics (2007)	Completed	’07: 2 ’08: 8
70(a)	Stub 8484	Segment 301, Mile Points 0.0034 – 0.0042	Alameda (Union City)	2007	PG&E conducted an engineering review in 2008 of this 2 foot segment located near Alvarado-Niles Rd & Decoto Rd in Union City. Based on review of pipe characteristics, this segment does not appear on the 2008 and 2009 lists.	Overall	Completed	’07: 10
70(b)	Stub 8485	Segment 301, Mile Points 0.00 – 0.002	Alameda (Union City)	2007 2008	PG&E has conducted an engineering review of this pipeline segment located near Alvarado Niles Rd & Decoto Rd in Union City. Based on review of pipe characteristics, this segment does not appear on the 2009 list.	Overall	Completed	’07: 11 ’08: 13