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Commissioner	:	C. Peterman
ALJ	:	A. Yip-Kikugawa
Witness	:	N. Skinner

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Report on the Results of Operations for Pacific Gas and Electric Company Test Year 2015 Gas Transmission and Storage Rate Case

Chapter 2
Safety and Risk Management

Supporting Attachments

San Francisco, California
January 13, 2015

OFFICE OF RATEPAYER ADVOCATES
PG&E TY2015 GT&S
EXHIBIT ORA-02
ATTACHMENTS A

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GTS-RateCase2015_DR_ORA_007-Q02

PG&E Data Request No.:	ORA_007-02		
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Request Date:	January 31, 2014	Requester DR No.:	ORA-GT&S-07
Date Sent:	February 26, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Jesus Soto	Requester:	Nathaniel Skinner

Chapter 2

QUESTION 2

Please provide the number of Department of Transportation (DOT) reportable excavation incidents and total DOT reportable incidents for PG&E, the industry, and PG&E's industry peer-group (Testimony at 2-7, bullet G discusses excavation damage). Please also provide a breakdown of incidents in High Consequence Areas, and by percentage in pipes installed before 1970 and before 1960.

ANSWER 2

In 2010 through 2012, natural gas transmission pipeline operators filed a total of 263 reportable incidents to the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA). Of these, 43 were reported as being caused by excavation damage. This compares with PG&E having a total of 14 reportable incidents to DOT's PHMSA from 2010 through 2012. Of the 14 reported by PG&E, 9 were reported as caused by excavation damage. PG&E interprets the word "peer" in this question to mean the natural gas operators who report incidents to PHMSA

In other words, approximately 16 percent of the natural gas transmission reportable incidents were caused by excavation damage during this period, whereas 64 percent of PG&E's reportable incidents were caused by excavation damage.[1]

None of the industry's reportable incidents caused by excavation damage from 2010-2012 occurred in a High Consequence Area (HCA). Two of PG&E's[2] eight reportable incidents caused by excavation damage from 2010-2012 occurred in an HCA.[3]

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1 Chapter 2 testimony states that over half of PG&E's reportable incidents were the result of excavation damage. The parenthetical indicates "57.1 percent" of PG&E's reportable incidents arose from excavation damage. Upon further examination of the data, we determined one additional incident – which occurred when a PG&E contractor struck and damaged the pipe – should also be included here. This changes the percentage from 57 to 64 percent.

Below is a table providing the data reported to PHMSA, including year of installation, for PG&E's reportable incidents between 2010-2012 which were caused by someone excavating on top of or near the pipeline.

Item	Report Date	City	Line	MP	HCA	Install Yea
1	10/29/2010	Salinas	301B	5.61	No	1952
2	12/29/2010	Madera	186	21.03	No	1954
3	7/11/2011	Rio Vista	114	2.98	No	1942
4	10/7/2011	Salinas	103	19.15	No	1930
5	4/5/2012	Martinez	SP3	181.42	Yes	1988
6	11/3/2012	Sunnyvale	109	6.7	Yes	1963
7	12/11/2012	Modesto	148	10.85	No	1947
8	12/28/2012	Madera	118B	7.8	No	1965
9	12/28/2012	Stockton	1609-01	1.64	Yes	1985

2 For purposes of the rate case, PG&E mileage includes Standard Pacific's miles. Likewise, for reportable incidents, these figures include those reported by PG&E on behalf of Standard Pacific. For clarity, one of PG&E's fourteen reportable incidents to DOT's PHMSA in this response occurred on Standard Pacific miles and that incident was caused by excavation damage.

3 PG&E discovered one reportable incident on its Annual Report for 2012 (on Line 118B near Madera) that was erroneously reported as occurring in an HCA. The correct designation is noted in the table in this response. PG&E will be correcting that error with PHMSA shortly.

GTS-RateCase2015_DR_ORA_007-Q05

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Date Sent:	February 14, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Jesus Soto	Requester:	Nathaniel Skinner

Chapter 2

QUESTION 5

For Figure 2-2 (Testimony at 2-20), please provide a similar figure for PG&E risk mitigation activities in 2011. Please indicate, for both Figure 2-2 and the new figure for 2011, which boxes contain programs to mitigate newly considered risks compared to PG&E activities:

a) Prior to 2010, and

b) Separately for the 2011-2014 period.

ANSWER 5

PG&E has not developed a figure similar to the one at Figure 2-2 in Chapter 2 for its risk mitigation activities in 2011. As discussed in Chapter 1 (pages 1-7 to 1-9), PG&E instituted an improved risk and asset management process, driven by the PAS 55 framework. The risk management process discussed in Chapter 2 (pages 2-10 to 2-19) was used to evaluate and rank risks, develop mitigation programs, and prepare the executable plan reflected in the programs proposed in this rate case. Figure 2-2 of Chapter 2 (page 2-20) illustrates the results of that work at a summary level, tying the proposed programs to the threats and resulting risks that they address. Since Figure 2-2 was developed as an illustrative tool for this proceeding, there is no comparable figure for prior years.

a) The risks identified and for which PG&E is proposing mitigation programs in this rate case period are not new. What is new is the process by which PG&E evaluates the risks and prioritizes the mitigation programs to address those risks. Inherent in this risk management process is the reliance on asset data. As we continue to mitigate risks and gain more information about threats to our assets across our entire system, the mix of work changes over time.

In years prior to 2014, PG&E managed threats arising from operations of its natural gas pipelines using a variety of methodologies and tools in accordance with applicable standards and regulations and based on the information available at that time. Through the newly-developed integrated asset management and risk-based decision-making process, PG&E has gained an enhanced view of system threats and the risks posed by those threats.

b) Please see PG&E's response to part (a), above.

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PG&E Witness:	Louis Krannich	Requester:	Nathaniel Skinner

Chapter 3

QUESTION 10

A - Please break down the spending, both in dollars and as the percentage of total, for each year between 2011-2014 between a) safety; b) integrity; c) reliability; and d) capacity. Please provide a similar breakdown for years 2015-2017.

B - Capital - Do MWCs 98 (Integrity Management) and 76 (Pipeline Reliability) encompass all work that was considered PSEP in 2011-2014? If not, what other capital work categories now include PSEP work, or that will be used for work performed in PSEP?

C - Expense - Do MWCs JT (Reliability and General Maintenance), HP (Transmission Integrity Management Program), and JV (Information Technology) encompass all work that was considered PSEP in 2011-2014? If not, what other expense work categories now include PSEP work, or that will be used for work performed in PSEP?

ANSWER 10

A) We do not segregate our programs into individual safety, integrity, reliability, and capacity categories. Many of our programs deal with multiple drivers and address multiple risks and therefore we do not believe it is appropriate to break them down into these individual categories.

Using a risk based decision making process, PG&E identified threats, assessed risks, and developed appropriate monitoring and mitigation programs to address and reduce those risks. As an illustration of how these programs address the ASME (American Society of Mechanical Engineers) threat categories, we created a Risk Mitigation Summary as seen in Figure 2-2 in Chapter 2 of PG&E's testimony on page 2-20. PG&E recommends using this summary to understand how programs identified in the 2015 GT&S Rate Case relate to threats and risks. To see a breakdown of our expenditures and forecast from 2011-2017 by Major Work Category see Table 3-4 and 3-5 in Chapter 3 of our testimony. Please refer to

Chapter 18 (pages 18-10 through 18-12) for a description of PG&E's post test year ratemaking proposal for expense adjustments for 2016 and 2017.

B) It is important to note that PG&E is not forecasting Pipeline Safety Enhancement Plan (PSEP) capital costs in this rate case. PG&E utilized a comprehensive risk based process to identify threats, assess risks, and develop appropriate monitoring and mitigation programs to address and reduce those risks. The forecast in the 2015 GT&S Rate Case is a product of this risk based process.

Some of the capital programs included in this rate case are similar in nature to programs executed under PSEP during 2011-2014, including Pipeline Replacement,[1] In-line Inspection Retrofits, Valve Automation, Strength Test Capital, Program Management Office (PMO) and capital expenditures for technology. The forecasts for these programs in the 2015 GT&S Rate Case can be found in Major Work Categories (MWC) 75, 98, 75, 75, 75, and 2F respectively; any capital StanPac costs are captured in MWC 44.

Please note that in its PSEP filing, PG&E proposed a set of gas transmission asset management tools and applications called the Gas Transmission Asset Management (GTAM) program. While the Commission did not allow cost recovery for the costs of GTAM, PG&E will complete this comprehensive data integration and consolidation initiative (now known as the Mariner Program) on schedule in early 2015. Completed projects in the Mariner Program will require normal ongoing system maintenance and enhancement costs, which PG&E did not request in its PSEP (that filing included only the development and implementation costs). The 2015 GT&S filing includes some projects that involve areas of technology similar to the tools and applications that were included in the Mariner program. However, these projects are all distinguishable from the projects proposed in the PSEP, and include enhancements to or replacements for existing technology.

Program	**Capital Expenditures Major Work Categories (MWC)**		
	2011-2014 PSEP	**2011-2014 Non-PSEP**	**2015-2017 Forecast**
Pipeline Replacement	2H	44, 75, 84, 2J	44, 75
ILI Retrofits	2H	44, 75, 98	44, 98
Valve Automation	2H	44, 75	75
Strength Test Capital	2H	75	75
PMO	2H	N/A	75
Capital Technology	2H	2F, 75, 2J	2F

1 PG&E's Vintage Pipe Replacement Program uses a different decision tree from that adopted in PSEP, but the activity of pipe replacement is the same in both programs.

C) It is important to note that PG&E is not forecasting PSEP expense costs in this rate case. PG&E utilized a comprehensive risk based process to identify threats, assess risks, and develop appropriate monitoring and mitigation programs to address and reduce those risks. The forecast in the GT&S Rate Case is a product of this risk based process.

Some of the expense programs included in this rate case are similar in nature to programs executed under PSEP during 2011-2014, including Strength Testing, In-line Inspection, PMO and expenses for technology. The forecasts for these programs in the 2015 GT&S Rate Case can be found in MWCs JT, HP, JT and JV, respectively; any expense StanPac costs are captured in MWC 34.

Please note that in its PSEP filing, PG&E proposed a set of gas transmission asset management tools and applications called the Gas Transmission Asset Management (GTAM) program. While the Commission did not allow cost recovery for the costs of GTAM, PG&E will complete this comprehensive data integration and consolidation initiative (now known as the Mariner Program) on schedule in early 2015. Completed projects in the Mariner Program will require normal
ongoing system maintenance and enhancement costs, which PG&E did not request in its PSEP (that filing included only the development and implementation costs). The 2015 GT&S filing includes some projects that involve areas of technology similar to the tools and applications that were included in the Mariner program. However, these projects are all distinguishable from the projects proposed in the PSEP, and include enhancements to or replacements for existing technology.

Program	Expense Major Work Categories (MWC)		
	2011-2014 PSEP	2011-2014 Non-PSEP	2015-2017 Forecast
Strength Testing	KE	34, II, JT, HP, KF	JT
ILI	KE	HP, II, JT, KF	34, HP
PMO	KE	N/A	JT
Expense Technology	KE[2]	JV, KF and JT	JV

2 Funding Identifiers are used to distinguish Mariner and non-Mariner costs that are included in MWC JV.

GTS-RateCase2015_DR_ORA_017-Q01

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PG&E Witness:		Requester:	Jonathan Bromson

SUBJECT: GTS-RATECASE2015_DR_TURN_001-Q01ATCH02, "METHOD FOR CALCULATING WEIGHTED RISKS AND DETERMINING THE HEAT MAP"

QUESTION 1

Please describe and explain the process used to determine the 6 specific "consequence categories" which PG&E utilized in its "risk assessment sessions failure scenarios of assets."

a. Did PG&E consider any other categories besides the six chosen?

b. Please provide the definitions of each of the 6 consequence categories, and the methodology PG&E uses to assess the magnitude of consequence in each category (i.e., how PG&E determines how much of a consequence a particular failure scenario has on Health and Safety, Regulatory Compliance, Environmental Impact, Reliability, Reputation, and Direct Financial Damage).

c. At what level of PG&E's organization are the weighting factors approved and given final sign-off before PG&E used them for analysis?

ANSWER 1

The choice of the six specific "consequence categories" was based on benchmarking of risk evaluation models used by other companies.

a. No, PG&E did not consider any other categories besides the six chosen.

b. Refer to Appendix 6, pages 37 – 42, of Utility Procedure TD-4011P-01, Rev. 0 (TURN_001-Q01Supp01Atch04) where the six categories are defined and the magnitude of consequence in each category is described.

c. The weighting factors used in PG&E's risk assessment are Safety (40%), Reliability (30%) and Financial (30%). The Chief Risk and Audit Officer approved the weightings and presented the approach to risk assessment, including the weighted risk evaluation tool, to the company's Risk Policy Committee, which includes

PG&E's most senior officers and the Chief Risk Officer, in March 2012. Since then, the company has revised the tool; however, it maintained the original categories and weightings.

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PG&E Witness:		Requester:	Jonathan Bromson

SUBJECT: GTS-RATECASE2015_DR_TURN_001-Q01ATCH02, "METHOD FOR CALCULATING WEIGHTED RISKS AND DETERMINING THE HEAT MAP"

QUESTION 2

PG&E states the following with respect to the 6 consequence categories: "Each of these categories of consequence of failure (CoF) has 7 levels of severity, increasing an order of magnitude for each next level. To be able to compare and weigh the 6 consequence categories, and to avoid translating human safety into monetary values, a dimensionless normalized consequence value is assigned to each level. These values are valid for every category and have been defined in the discussion with the AFO's and McKinsey. The approach taken here is that they differ between each consecutive level a constant factor and the highest level is designated a normalized number of 100."

a. Please explain how PG&E determined that for each consequence category the consequence of failure has 7 levels of severity, as opposed to a different number of levels of severity.

b. Please explain in full why PG&E chose "to avoid translating human safety into monetary values." Could PG&E have been able to compare and weigh the 6 consequence categories had a monetary value been utilized to evaluate human safety?

c. Please explain what is meant by a "dimensionless normalized consequence value" and how such a value was determined.

d. To what discussion(s) does the phrase "the discussion with the AFO's and McKinsey" refer? Please provide records of the time of this discussion(s) with Asset Family Owners and McKinsey, names of people involved, and any notes or documents regarding such discussions.

ANSWER 2

PG&E is providing attachment GTS-RateCase2015_DR_ORA_017-Q02Atch01 to demonstrate how the risk evaluation tool calculations work. The document walks the reader through the 5 steps, including all of the calculations, to create a risk consequence score.

a. The 7 levels of severity provide PG&E the ability to identify a wide range of consequences. During the risk evaluation tool development, the Corporate Enterprise Risk Management (ERM) team examined five, seven and ten levels of severity and found that seven provided the right balance of adequate granularity while avoiding false precision.

b. PG&E's highest risk management priority is to identify, assess and mitigate the threats that could affect human life. PG&E's safety consequence category includes in its highest score (7), "imminent and inevitable threat to lives." It is not necessary to assign a dollar value to human life to identify, assess and mitigate a threat to life.

c. Dimensionless normalized consequence value can be defined in two parts. Consequences are dimensionless (unit-less) because each category (Safety, Environmental, Reliability, and so on) of consequence of failure is assessed and scored independently against a similar scale. For example, if evaluating the consequence of failure of a long-seam pipe, the first category, Safety, is evaluated followed by Reliability, Environmental, and so forth. To establish the overall consequence of failure, PG&E aggregates the total consequence of each category, which is done by using the dimensionless scale.

   The dimensionless scale was set with a maximum of 100 and a minimum near zero. In order to derive the scale for each intermediate consequence category (1 to 7), a mathematical normalization was used to translate a linear scale (1 to 7) to a logarithmic scale (0 to 100). This process is similar to that of the Richter scale which is a logarithmic scale. A magnitude 5.0 earthquake is 10,000 times more powerful than a magnitude 1.0 earthquake. The formula used to calculate normalized consequence value is: $0.000456.e^{1.7569.N}$ = Consequence score of 1 – 100, where N
   is the consequence level from 1 to 7.

d. In GTS-RateCase2015_DR_TURN_001-Q01Atch02, PG&E referred to a "discussion with the AFO's and McKinsey." You have requested "records of the time of this discussion with AFO's and McKinsey, names of people involved, and any notes or documents regarding such discussions." We are precluded under our agreement with McKinsey from attributing to McKinsey any specific recommendations resulting from McKinsey's work for PG&E. We believe that responding to the specifics of your data request could cause PG&E to cross the line with respect to this confidentiality commitment to McKinsey. We therefore decline to respond further to question 2.d.

GTS-RateCase2015_DR_ORA_017-Q02
Attachment 1

PG&E Gas Risk Register Reference for Consequence.

Gas Operations' first risk register was published in 2013. The formulas behind the final result, especially for consequences of failure, require some explanation to understand. This fact sheet walks through the steps that result in the final score for consequence of failure.

1. Establish Consequence Scores.

PG&E chose 7 scores, numbered 1 through 7, with 7 being highest consequence and 1 being lowest consequence, that can be applied to each category of consequence. For each category, a score is determined based on guidance provided (see the table below for examples of the guidance provided). For example, a health and safety score of 7 is "catastrophic", and is defined as resulting in an event that causes loss of multiple lives.

Categories	Examples from the Range of Consequence Scores (1 – 7)
Safety	1 - Very low population and minor injury; 3 – Class 2 location and PG&E employees often in close proximity with threat to one member of public requiring extended medical treatment; 7 – imminent and inevitable threat to lives
Regulatory Compliance	2 – Few or no regulatory complaints/citations expected; 4 –a warning letter; a notice of non-compliance or notice of violation; 6 – regulatory penalty or legal action including incarceration or large fines, non-compliance is system-wide
Environmental Impact	3 – less than <0.1 acre environmental damage; 5 – hazardous material release to water used by humans or livestock; 7 – non-reversible impact
Reliability	1 – local disruption (10 residents without gas for 2 non-peak hours); 4 – failure resulting in low pressure at a localized scale with a value of service equivalent to $7 - $40 million
Reputation	3 – local media coverage; 5 – less than one week of national and international media coverage; 7 – more than 6 months of national and international media coverage
Direct Financial Damage	1 – less than $30k; 5 - $7 - $40 m; 7 – greater than $250 million

2. Rank Health and Safety Scores Higher than Financial Outcome Scores

In this step, we apply an adjustment to assure that the Health and Safety consideration is never outweighed by Financial consideration.

In the risk example below, TRA-6, the risk of excavation damage, the Financial Risk is ranked a "3". On the surface, it appears that this score is less than the Health and Safety score, which is "6". However if risk "X" had a Health and Safety score of "3" and a Financial score of "6" with all other scores the same, TRA-6 and Risk "X" would be ranked equally in total, which would not recognize the higher Health and Safety risk associated with risk TRA-6.

To prevent this situation from occurring, when a risk like TRA-6 is entered into the risk register, the system always adjusts the Financial score to 6. This step assures that risks with a Health and Safety score higher than the Financial score are always ranked higher in total because the overall score now will always be higher than a risk with a lower Health and Safety, but higher Financial score So now, our scores for TRA-6 are what we see in (red) below.

Example: Risk TRA-6. The risk of mechanical damage to the pipeline.

Causes might include:

- Incorrect mark and locate
- Not following instructions
- Inadequate depth of cover

Consequence Scores:

Health & Safety = 6 (6)
Regulatory Compliance = 5 (5)
Environmental Impact = 5 (5)
Reliability = 5 (5)
Reputation = 6 (6)
Financial = 3 (6)

3. Scale consequences logarithmically

In this step, risk consequence scores are converted to a logarithmic scale in order to better differentiate among risks. To convert the one through seven linear scoring to a non-linear equation, the following formula is applied to each of the six consequences:

Health & Safety = 0.000455948900966988*EXP(1.7569 x 6)

Health and Safety =17.25790304

The formula is very typical to determine a slope of a tangent line (e.g. a non-linear equation). EXP is "E" to the power, in this case to the power of 1.7569 x 6. "E" is a constant in math and is approximately 2.718. This formula was tested using the dollar values associated with the Reliability consequences. Applying the same formula as we did above, the scores for Risk TRA-6 are now:

Health & Safety =17.25790304
Regulatory Compliance = 2.978352174
Environmental Impact = 2.978352174
Reliability = 2.978352174
Reputation = 17.25790304
Financial = 17.25790304

4. Weight Consequences

Results up to this point, with the exception of the prioritization of Health and Safety over Financial outcomes are equally weighted. PG&E weights the results consistently with overall corporate objectives to provide safe, reliable and affordable service. Here are the weightings:

Weight	Risk Consequence Category	Weight
Safety (40%)	Health and Safety	30%
	Regulatory Compliance	5%
	Environmental Impact	5%
Reliability (30%)	Reliability	25%
	Reputation	5%
Financial (30%)	Financial	30%

Here is the calculation using the green number from step 3, again for Health and Safety:

17.25790304 x .3 = **5.177370913**

The weighting is applied to the scores for each of the 6 consequence categories:

Health & Safety = **17.25790304** x .30 = **5.177370913**
Regulatory Compliance = 2.978352174 x .05 = **0.148917609**
Environmental Impact = 2.978352174 x .05 = **0.148917609**
Reliability = 2.978352174 x .25 = **0.744588044**
Reputation = 17.25790304 x .05 = **0.862895152**
Financial = 17.25790304 x .30 = **5.177370913**
Total = *12.26006024*

5. Prioritize Health and Safety

The final step is to apply an additional adjustment to assure that Health and Safety receives top priority over all other consequences. For example, if a particular threat was scored with a Health and Safety consequence of 5 in Step 1 (normalized score of 2.95) while all other consequences scored a 1, the weighting in Step 4 would produce an overall combined consequence score of 0.895 which corresponds to a category 4 Health and Safety consequence. Translating this to words using the PG&E risk matrix, this would mean that because there are no significant consequences aside from Health and Safety, the overall consequence of the event would be downgraded from indicating "threat of permanently incapacitating injury to one member of the public or imminent threat of life to one employee" (the outcome associated with an initial Health and Safety score of 5 from Step 1) to "threat of injury

to one member of public requiring extended medical treatment" (the outcome associated with an initial Safety score of 4 in Step 1). This result does not prioritize Health and Safety appropriately.

To address this potential scenario, the scores from Step 4 are divided by .3, effectively increasing all of the final scores so that the total consequence score is never reduced below the Health and Safety value. Here's the calculation using the result in purple from step 4 for the Health and Safety risk:

Health and Safety = **5.177370913/.3**

Final Health and Safety Score = 17.257

This step does not change the ranking order of the risks. Here are the results:

Health & Safety =	17.25790304	Reliability =	2.481960145
Regulatory Compliance =	0.496392029	Reputation =	2.876317174
Environmental Impact =	0.496392029	Financial =	17.25790304
Total =	**40.8668674**		

These adjustments are applied universally across all risks so that the priority of Health and Safety is consistently emphasized.

GTS-RateCase2015_DR_ORA_017-Q05

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PG&E Witness:		Requester:	Jonathan Bromson

SUBJECT: GTS-RATECASE2015_DR_TURN_001- Q01ATCH02, "METHOD FOR CALCULATING WEIGHTED RISKS AND DETERMINING THE HEAT MAP"

QUESTION 5

PG&E states the following: "The likelihood of failure (LoF) is presented as a frequency, which also increases by an order of magnitude for each higher level. The highest frequency is 10 times per year and the lowest is 1/100,000 times per year."

Please explain how PG&E determined the highest and lowest frequency levels of 10 times per year and 1/100,000 times per year for use in its LoF determination.

ANSWER 5

PG&E selected seven different levels of frequencies to use in its risk assessment model because it provides a method to establish the relative ranking of one potential risk versus another potential risk. PG&E selected the frequency of "more than 10 times per year as having the highest score and the frequency of "more than every 10,000 years" as the likelihood with the lowest score[1] based on benchmarking of risk evaluation models used by other companies and frequency of incidents at PG&E. In addition, PG&E's risk management scoring includes five other gradations of potential frequency between these two extremes including (from highest to lowest score):

- One to 10 times per year
- Once every 1 -10 years
- Once every 10 – 100 years
- Once every 100 – 1000 years
- Once every 1,000 -10,000 years

[1] See attachment GTS-RateCase2015_DR_TURN_001-Q01Supp01Atch04 Utility Procedure: TD-4011P-01, Publication Date 07/31/2013, Gas Operations Asset Management Systems Risk Management, p. 35.

The categorization of the likelihood a particular threat will cause a specified failure is based upon a combination of expert judgment, experience, and technical knowledge. As such, the categorization, and resulting risk ranking score, is not intended to predict the mathematical probability of that specific failure occurring at any given time, but instead, to establish a relative ranking of the likelihood of failure. Such relative rankings help inform PG&E of which threats likely constitute its highest risks, and as such assists PG&E with making sound decisions regarding operation, maintenance and risk mitigation efforts.

GTS-RateCase2015_DR_ORA_017-Q06

PG&E Data Request No.:	ORA_017-06		
PG&E File Name:	GTS-RateCase2015_DR_ORA_017-Q06		
Request Date:	March 3, 2014	Requester DR No.:	ORA-GT&S-17
Date Sent:	April 1, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:		Requester:	Jonathan Bromson

SUBJECT: GTS-RATECASE2015_DR_TURN_001- Q01ATCH02, "METHOD FOR CALCULATING WEIGHTED RISKS AND DETERMINING THE HEAT MAP"

QUESTION 6

Please explain how PG&E's ERM department "set" the "weighted scoring method" and determined the specific "weighing factors" listed in Table 2, "Weighing factors of the consequence categories."

Please provide support for the statement: "Most failure scenarios have consequences in more than one consequence category."

ANSWER 6

PG&E's Risk Evaluation Tool was designed to produce a priority list of risks that are aligned with the company's objectives. This meant the tool needed to place an emphasis on the top risks that could threaten PG&E's ability to deliver safe, reliable, and affordable gas and electric service. To achieve this, Safety related consequences in the risk register, and listed in Table 2 of the Method for Calculating Weighted Risks and Determining the Heat Map, are weighted at 40% by adding Health and Safety at 30%, Environment at 5%, and Regulatory Compliance at 5%. Reliability consequences are weighted at 30% between Reliability at 25% and Reputation at 5%, and finally, Financial consequences are weighted at 30%. The weighting of these factors mirror the weighting of the same factors included in PG&E's short term incentive plan (STIP) (Safety – 40%, Reliability – 30%, and Financial – 30%), which also are aligned with management's goal of delivering safe, reliable and affordable gas and electric service

"Most failure scenarios have consequences in more than one consequence category" means that most risks have a consequence score across all six categories (Safety and Health, Environment, Regulatory Compliance, Financial, Reputation, and Reliability.) In the example introduced in PG&E's response to ORA_017-Q04, risk TRA-6, Mechanical Damage, had consequence scores in all six of the consequence categories: Health and Safety, Regulatory Compliance, Environment, Financial, Reputation, and Reliability.

See the Risk Register (TURN_01-Q01Atch03CONF), Columns E through J of the "Summary Risk Scores" tab for the consequence scores of each risk in each category.

GTS-RateCase2015_DR_ORA_017-Q08

PG&E Data Request No.:	ORA_017-08		
PG&E File Name:	GTS-RateCase2015_DR_ORA_017-Q08		
Request Date:	March 3, 2014	Requester DR No.:	ORA-GT&S-17
Date Sent:	April 1, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:		Requester:	Jonathan Bromson

SUBJECT: GTS-RATECASE2015_DR_TURN_001- Q01ATCH02, "METHOD FOR CALCULATING WEIGHTED RISKS AND DETERMINING THE HEAT MAP"

QUESTION 8

PG&E states: "The weighing of the consequence levels has to be done on the basis of the values as mentioned in table 1. However this results in a dilution due to the weighting factors and to a dissatisfying and contra-intuitive result as the overall risk is lower than the original Health and Safety value. To compensate for this effect, the result is divided by the health and safety weight factor."

a. Please explain why the weighting factors mentioned in table 1 results in a "dilution." What does PG&E mean by "dilution"?

b. Please explain what PG&E meant by "a dissatisfying a contra-intuitive result as the overall risk is lower than the original Health and Safety value"?

c. For what "effect" does dividing the result by the health and safety weight factor compensate? Does dividing the result by the health and safety weight factor yield an "intuitive" result? Please explain in full.

d. In Table 3, "The calculation of the weighted risk values," please explain what is meant by the column "Avoiding dilution units." Please define and explain "dilution units."

e. Please provide the underlying formulae and variables PG&E used in creating Table 3.

f. Aside from the adjustment PG&E did to the formulae, is there another alternative approach PG&E considered that did not lead to counter-intuitive results? If so, please provide the notes and documents from those approaches.

ANSWER 8

As stated in GTS-RateCase2015_DR_ORA_017-Q02, GTS-RateCase2015_DR_ ORA_017-Q02Atch01 describes the five steps to create the consequence score as well as the reasons why those steps were chosen.

a. Dilution is a final risk score that is less than the normalized Health and Safety score. In Table Q8B below, showing an example for risk TRA-6, if PG&E used the sum of the normalized and weighted consequence scores in the risk register entry, the sum of all of the scores (Column F, Row 7 - 12.260) would be less than the logarithmic score for Health and Safety (Column D, Row 1 - 17.257).

b. PG&E designed the risk consequence scoring so that the final consequence score would be at least as high as the normalized Health and Safety consequence score so that Health and Safety would be fully appreciated. See part (a), above.

c. Dividing the health and safety weight factor by 0.3 assures that the final consequence score is at least as high as the normalized Health and Safety score. Since safety is the most important of the consequence categories, it makes sense that a final consequence score would at least result in a Health and Safety consequence score that matched the normalized Health and Safety scores. PG&E believes this conservative approach is appropriate.

   In addition, when viewing the risk register, there is a difference in the consequence values shown on the "Risk Matrix Input Data" and the "Risk Matrix Input Data (ERM Fin)" tabs.[1] The reason for this difference is to further apply conservatism when comparing Financial and H&S consequence scores with the expectation that the final risk ranking places H&S consequences above Financial consequences. Although PG&E weights consequence scores at 30% for each Health and Safety and Financial, PG&E prioritizes Health and Safety over Financial consequences. PG&E adjusted consequence scores where the Financial consequence score could cause the risk to rank higher than one with an equal or greater Safety and Health consequence score.

   In Table Q8A below, row 1 shows the subject matter expert input for the consequence values. Note that the column K result is 23.698. Compare the row 1 example to the row 3 example, where for illustration purposes, the H&S score (Column E) has been flipped with the Financial score (Column J), the Column K result is the same, 23.698. This could lead to a consequence with a higher Financial score being placed on the risk register equally with a consequence that has a lower H&S score. To prevent this situation from occurring, if the Financial Score was initially entered as a lower number than the H&S score, it is increased to match the H&S score (see the row 2 example) in the "Risk Matrix Input Data (ERM Fin)" tab in the Risk Register. Column K in row 2 now shows that the consequence value is 40.867, assuring that it is ranked higher on the Risk Register than the illustrative scenario provided in row 3.

[1] See attachment GTS-RateCase2015_DR_TURN_001-Q01Atch03CONF.

The model verifies that the Financial CoF score is at least as high as the H & S CoF to make sure consequences with a higher H&S score are prioritized above consequences with a higher financial score.

TABLE Q8A

Example: TRA6 risk in Transmission Asset Family

	Columns in "Risk Matrix Input Data" and "Risk Matrix Input Data (ERM Fin)" Tabs from the Risk Register Excel File								Column (D) x Column (K)
	D	E	F	G	H	I	J	K	
	LoF	H&S (30%)	RC (5%)	EI (5%)	Rel (25%)	Rep (5%)	Fin (30%)	Normalized Weighted Avoided Dilution Consequence Value	Risk Score
(1) Values in the "Risk Matrix Input Data" tab	0.011	6	5	5	5	6	3	23.658	0.26
(2) Values in the "Risk Matrix Input Data (ERM Fin)" tab	0.011	6	5	5	5	6	6	40.867	0.45
(3) Further illustration of how H&S scores always drive value in overall risk score (Column D x Column K)	0.011	3	5	5	5	6	6	23.658	0.26

d. The "Avoiding Dilution Units" applies to the methodology documented in Table Q8A where the adjusted consequence units are divided by the H&S factor of 0.3, i.e., Adjusted Consequence Units / H&S Factor (0.3) = "Avoiding dilution units." This is to ensure that the overall consequence value is not 'diluted' as explained in Response 8a and 8c.

e. See excel file GTS-RateCase2015_DR_ORA_017-Q04Atch01 for the underlying formulas and variables used to create Table 3. Additionally, they are shown below for all of the calculations in row 1 of the excel file GTS-RateCase2015_DR_ORA_017-Q04Atch01.

Translating to a Logarithmic Scale (Normalizing) – Column D, Row 1
17.25790304=0.000455948900966988*EXP(1.7569*H&S Score of 6). In this case "EXP" is the constant "E" to the power of the numbers by which it is multiplied. "E" is approximately 2.72.

Normalized and Weighted Consequence Score – Column F, Row 1

5.177370913 = 17.25790304 x .3

Avoiding Dilution – Column G, Row 1

17.2579034 = 5.177370913/.3

f. PG&E Gas Operations did not consider another alternative and chose the current methodology to stay consistent with the overall corporate weighting system.

GTS-RateCase2015_DR_ORA_019-Q05

PG&E Data Request No.:	ORA_019-05		
PG&E File Name:	GTS-RateCase2015_DR_ORA_019-Q05		
Request Date:	March 6, 2014	Requester DR No.:	ORA-GT&S-19
Date Sent:	March 20, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Jesus Soto	Requester:	Nathaniel Skinner

SUBJECT: SUPPLEMENTS TO DR_ORA_007-Q02

QUESTION 5

PG&E provided a table in response to ORA DR-07, Question 2. Please supplement this table with the following additional information.

a. Who caused the incident (PG&E, PG&E contractor, 3rd party, or unknown);

b. What impact the excavation had on the pipeline (e.g. pinhole leak, rupture, etc), consistent with any reporting requirement to the Department of Transportation (if applicable);

c. The actual or estimated (indicate which) damages associated with the incident;

d. The cost of fixing that incident; and

e. Which proposed programs in the 2015 GT&S, if any, would help prevent this type of incident. If a program is proposed, please indicate the chapter(s) and page(s) in PG&E's testimony and workpapers that describe the program.

ANSWER 5

a. Included in attachment GTS-RateCase2015_DR_ORA_019-Q05Atch01 is a table providing the data reported to PHMSA for PG&E's reportable incidents from 2010 to 2012, which were caused by someone excavating on top of or near the pipeline. Columns A-G are repeated from the table provided in PG&E's response to GTS-RateCase2015_DR_ORA_007-Q02. Columns H-L have been added to address the information requested in this question. The cause of the excavation damage is set forth in Column K. . Column L provides a reference to the PG&E tracking number .

b. The type of damage caused to the pipeline is set forth in column H in attachment GTS-RateCase2015_DR_ORA_019-Q05Atch01.

c. The amount of damages estimated at the time of the report is set forth in column I in attachment GTS-RateCase2015_DR_ORA_019-Q05Atch01.

d. The actual cost of repairing the damage is set forth in column J in attachment GTS-RateCase2015_DR_ORA_019-Q05Atch01.

e. PG&E has proposed several programs to help reduce the number of excavation damage incidents. Those programs, along with the location in testimony where they are discussed, include:
   - Public Awareness and Damage Prevention program. These programs are designed to inform people living in proximity to its pipelines of the risk associated with natural gas pipelines and to prevent damage to pipelines. See Chapter 4A, page 4A-75.
   - The Locate and Mark program, which is intended to prevent excavation damage by third-party contractors. See Chapter 8, pages 8-11 to 8-13.
   - Right of Way Management and Patrols, including Pipeline Mobile Patrol programs. These programs are designed to 1) enhance our ongoing programs, including shallow pipe, and 2) improve PG&E's ability to identify work in progress near our pipelines and past damage that could result in an incident later and analyze the integrity of the gas transmission system, thereby enhancing system safety. See Chapter 8, page 8-6.
   - The Shallow Pipe program which is intended to identify, prioritize and mitigate locations where pipeline has reduced cover and is vulnerable to exposure from third parties, including agricultural activities. See Chapter 4B, pages 4B-19 to 4B-27
   - The Training and Operator Qualification which are to both train employees so that they have the technical knowledge to perform tasks in a safe, reliable and efficient manner, and to confirm that technical learning has been absorbed and mastered by employees. See Chapter 8, pages 8-7 through 8-9.
   - In-Line Inspections Program to enable PG&E to learn about the condition of the pipelines, and to predict the integrity of those pipelines into the future to address time dependent threats and time independent threats, such as past damage to the pipeline, as well as other threats to pipeline integrity. See Chapter 4A, pages 4A-5 to 4A-24.

GTS-RateCase2015_DR_ORA_019-Q05
Attachment 1

Item	Report Date	City	Line	MP	HCA	Install Year	Type	Estimated Damages at Time of Report	Actual Cost to Repair	Cause	PSRS
1	10/29/2010	Salinas	301B	5.61	No	1952	2.5" X 5" puncture	$ 90,512	$ 46,038	3rd party ag field ripping	22355
2	12/29/2010	Madera	186	21.03	No	1954	puncture	$ 82,000	$ 105,315	3rd party ag field ripping	22905
3	7/11/2011	Rio Vista	114	2.98	No	1942	6" puncture	$ 70,000	$ 85,798	3rd party grading activity	24711
4	10/7/2011	Salinas	103	19.15	No	1930	1" X 2" puncture	$ 60,000	$ 78,458	3rd party ag field ripping	25218
5	4/5/2012	Martinez	SP3	181.42	Yes	1988	Crack on gauge line	$ 60,000	$ 131,025	PG&E Crews at fault	27710
6	11/3/2012	Sunnyvale	109	6.7	Yes	1963	Crack on tee off 109	$ 25,000	N/A[1]	PG&E Contractor at fault	N/A
7	12/11/2012	Modesto	148	10.85	No	1947	4" X 2.5" puncture	$ 85,000	$ 96,556	3rd party ag field ripping	29101
8	12/28/2012	Madera	118B	7.8	No	1965	Puncture	$ 350,450	$ 356,959	3rd party excavating activity	29222
9	12/28/2012	Stockton	1609-01	1.64	Yes	1985	Integrity damage led to weakening and eventual rupture	$ 465,000	$ 676,778	PG&E Electric crew at fault	29228

[1] this portion of the 22" L-109 pipeline was in the process of being retired when it was damaged and was therefore not repaired

GTS-RateCase2015_DR_ORA_019-Q07
Attachment 1

2014 Session D

GAS OPERATIONS

Entire Gas Operations Risk Register (1 of 25)

	Risk Name	Risk Description	Risk Type	Category	Key Controls	Current Residual Risk Score	Risk Status as of 1/31/2014
1	TRA1 - External Corrosion (System Safety)	Rupture of transmission pipeline due to external corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damages and/or significant environmental damage. (P95 case)	Operational	Transmission	- Pipe-to-soil testing - Cathodic Protection Area (CPA) - Casing monitoring - Leak survey - Close interval survey (CIS) - Direct Assessments	788	Controls are being strengthened
2	TRA3 - Welding / Fabrication Related - Pre-1962 Construction with Land Movement (System Safety)	Circumferential rupture of vintage construction pipe (pre-radiographic pre-1962 girth welds, wrinkle bends, dresser couplings, miter bends, etc.) in known regions of geo-hazards and localized landslide zones may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages. Risk drivers: due to lack of redundancy on radial feeds.	Operational	Transmission	- QC - Welder qualifications - Targeted inspections - Risk assessment of vintage pipe segments	785	Controls are being strengthened
3	TRA8 - Internal Corrosion (System Safety)	Rupture of transmission pipeline due to internal corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage . (P95 case) Risk drivers: due to lack of redundancy on radial feeds. due to liquids escaping pipeline.	Operational	Transmission	- Gas quality monitoring set with alarms for CO_2 and H_2S - Gas dehydration and separation - Leak survey - Direct Assessments	583	Current controls are not adequate
4	TRA4 - Manufacturing Related Defects - Older Seam Types (System Safety)	Longitudinal rupture of transmission pipe with specific seam types (low frequency ERW, AO Smith, lap weld, flash weld, butt weld or pre-1990 spiral) may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages. (P95 case) Risk drivers: due to lack of redundancy on radial feeds.	Operational	Transmission	- Supplier Approval - Material Specification - Product Inspection - Design Standards - Material Problem Report (MPR) Program	581	Controls are being strengthened
5	TRA12 - Weather Related & Outside Forces - Land Movement (System Safety)	Pipeline failure due to land movement associated with seismic activity, weather events, or other geo-hazards (e.g levees) may result in the uncontrolled flow of gas that can lead to impact on public or employee safety, prolonged outages, property damage.	Operational	Transmission	- Patrols - Geotechnical Hazard Monitoring - Shallow Pipe Program	548	Controls are being strengthened

Analysis in progress, status unknown or under evaluation | Current controls are not adequate | Controls are being strengthened | Current controls are adequate

GTS-RateCase2015_DR_ORA_019-Q07
Attachment 2

Final - 4-23-2014

2014 Session D

GAS OPERATIONS

Gas Operations Transmission Asset Family Top Risks

2014 Session D includes 6 Gas Transmission risks in the top 10. Each of these risks map to programs included in the 2015 GT&S Rate Case:

TRA1 – Catastrophic Pipeline Failure - External Corrosion

Total Risk Miles	1,706 (29% of PG&E)
Unassessed Risk Miles	637 (11% of PG&E)

TRA3 – Catastrophic Pipeline Failure - Welding/Fabrication Related - Pre-1962 Construction with Land Movement

Total Risk Miles	66 (1% of PG&E) [1]
Unmitigated Risk Miles	66 (1% of PG&E) [1]

TRA8 – Catastrophic Pipeline Failure - Internal Corrosion

Total Risk Miles	859 (15% of PG&E)
Unassessed Risk Miles	~ 699 (~12% of PG&E) [2]

TRA4 – Catastrophic Pipeline Failure - Manufacturing Threat Associated with Older Seam Types

Total Risk Miles	490 (8% of PG&E)
Unmitigated Risk Miles	148 (3% of PG&E)

TRA12 – Catastrophic Pipeline Failure - Weather Related & Outside Forces – Land Movement

Total Risk Miles	1,672 (29% of PG&E)
Unassessed Risk Miles	379 (7% of PG&E)

TRA6 – Third Party/Mechanical Damage

Total Risk Miles	1,706 (29% of PG&E)
Unassessed Risk Miles	637 (11% of PG&E)

Total Transmission Miles	**5,791**
Total HCA Miles	**1,076**
Total Miles Considered for All Risks (Class 3, Class 4, HCA Class 1, HCA Class 2)	**1,706**

Transmission Pipeline Piggability

	PG&E	National Average [3]
Total Miles Piggable	25%	68%
Immediate Anomaly Rate (per 100 miles)	1.4	0.31

Definitions:

Total risk miles - total miles of pipe in Class 3 and 4 or Class 1 and 2 HCAs where the risk is identified as active according to the TIMP threat identification process.

Unassessed risk miles - miles of pipe that have not yet been assessed for the identified risk using an integrity assessment method. Integrity assessments include in-line inspection (ILI) or direct assessment (ECDA or ICDA).

Unmitigated risk miles - miles of pipe that have not been mitigated for the identified risk. Mitigation is either strength testing for the manufacturing risk or pipeline replacement for the construction risk.

1. Total mileage, including all non-HCA miles, associated with this risk is 375 miles (6% of PG&E)
2. Excludes miles assessed by Internal Corrosion Direct Assessment (ICDA) only
3. Based on 2011 INGAA Survey

GTS-RateCase2015_DR_ORA_023-Q06

PG&E Data Request No.:	ORA_023-06		
PG&E File Name:	GTS-RateCase2015_DR_ORA_023-Q06		
Request Date:	March 12, 2014	Requester DR No.:	ORA-GT&S-23
Date Sent:	March 27, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Nick Stavropoulos	Requester:	Nathaniel Skinner

SUBJECT: INTRODUCTION AND POLICY

QUESTION 6

PG&E states in Chapter 1 (pages 1-4 and 1-5) that "the GT&S forecast resulted from the next stage in development and implementation since PG&E's 2014 GRC application and its consistent with the evaluation criteria Cycla set forth in its 2014 GRC report."

a. Please provide a copy of the Cycla 2014 GRC report.

b. Please indicate which evaluation criteria from the Cycla report PG&E is using for the 2015 GT&S Application.

c. Where PG&E has modified or changed any criteria, please describe the change, the reason for the change, and provide a table comparing Cycla's recommendation with PG&E's use.

d. As a result of the 2014 GRC, what changes occurred in the 2015 GT&S filing?

ANSWER 6

Attachments to this response have been marked CONFIDENTIAL and are submitted pursuant to Section 583 of the Public Utilities Code because it includes employee names below the Director level.

a. See attachment GTS-RateCase2015_DR_ORA_023-Q06Atch01.

b. The Cycla Report identified ten "Evaluation Criteria" that Cycla believes apply to an operator's overall risk-informed resource allocation process. PG&E did not "use" any of these criteria in its 2015 Gas Transmission and Storage (GT&S) Application. However, the risk-informed resource allocation process that PG&E used to develop the forecast presented in its 2015 GT&S Application is consistent with the Evaluation Criteria, as described more fully in the following table:

Evaluation Criterion	Related PG&E Process
1. An operator must develop, document, implement and maintain a risk-informed resource allocation process for the ongoing identification, evaluation and management of asset-related risks. The process must include identification, selection, implementation and effectiveness monitoring of risk control measures (RCMs) throughout the life cycle of the pipeline system.	See: 1) GTS-RateCase2015_DR_TURN_001-Q01Supp01Atch02 (Utility Standard TD-4011S: Gas Operations Asset Management System Risk Management); 2) GTS-RateCase2015_DR_TURN_001-Q01Supp01Atch04 (Utility Procedure TD-4011P-01– Gas Operations Asset Management Systems Risk Management); and 3) GTS-RateCase2015_DR_TURN_001-Q01Atch13 (Gas Operations Investment Planning). Review of some risk control measures takes place during a Gas Operations Daily Briefing call and other risk control measures are reviewed during Risk and Compliance Committee meetings. Finally, the performance of each asset family is reviewed annually during the Strategic Asset Management review (GTS-RateCase2015_DR_ORA_019-Q08Atch01).
2. Executive management must be involved to ensure that the risk-informed resource allocation process seeks out and considers safety risks, and that resource decisions adequately address recognized safety risks.	See GTS-RateCase2015_DR_TURN_001-Q01Atch13 (Gas Operations Investment Planning), Section 8, page 5 of 8 and GTS-RateCase2015_DR_TURN_001-Q01Supp01Atch02 (Utility Standard TD-4011S: Gas Operations Asset Management System Risk Management), Section 3.1, subsection 3, referring to oversight by the Risk Policy Committee, which includes PG&E and PG&E Corporation's CEO, as well as seven PG&E and/or PG&E corporation officers, the Utility Risk Management Committee which includes seven officers of PG&E or PG&E Corporation and is chaired by PG&E's CEO or President, and the Gas Operations Risk and Compliance Committee is is chaired by the Executive Vice President, Gas Operations and includes Gas Operations officers who report directly to the Executive Vice President.
3. The results from application of an operator's risk-informed resource allocation process must provide support for the safety-related proposals in its periodic Rate Case filings.	As discussed in Chapter 2 of PG&E's testimony, PG&E's 2015 GT&S forecast was developed using PG&E's asset and risk management processes. See Table 2-1 of Prepared Testimony for a graphic depiction of the process.
4. The risk-informed resource allocation process documentation must include a description of the procedure for making decisions on selection of RCMs proposed in the rate case, including enumerating responsibilities for	See: 1) GTS-RateCase2015_DR_TURN_001-Q01Supp01Atch04 (Utility Procedure TD-4011P-01– Gas Operations Asset Management Systems Risk Management, page 3; and 2) GTS-RateCase2015_DR_TURN_001-Q01Atch13 (Gas

Evaluation Criterion	Related PG&E Process
implementing this procedure.	Operations Investment Planning).
5. The risk-informed resource allocation process must include means by which an operator monitors the overall effectiveness of its efforts to control risk and the effectiveness of individual RCMs using a documented set of leading and lagging indicators that are periodically reviewed for appropriateness.	See: 1) GTS-RateCase2015_DR_TURN_001-Q01Atch04 (Session D Presentation); and 2) GTS-RateCase2015_DR_TURN_001Q01Atch06 through Atch11CONF (Asset Management Plans), Sections 4.2 and 5.3. Review of some risk control measures takes place during a Gas Operations Daily Briefing call and other risk control measures are reviewed during Risk and Compliance Committee meetings. Finally, the performance of each asset family is reviewed annually during the Strategic Asset Management review (GTS-RateCase2015_DR_ORA_019-Q08Atch01).
6. One critical source of information both on sources of risk and on the effectiveness of measures to control risk in pipeline systems is data on the location and underlying causes of various types of failures affecting system integrity. An operator must thoroughly evaluate, understand and make appropriate use throughout the process of its understanding of the root causes of a spectrum of events ranging from system leaks to serious incidents.	Gas Operations Risk Management Process, depicted in Prepared Testimony Figure 2-1 includes 1) threat identification and risk assessment, 2) developing proposed mitigation programs, and 3) developing an executable investment plan. The following procedure describes the type of data used to identify and evaluate risks and methods for risk and mitigation effectiveness evaluation, see GTS-RateCase2015_DR_ TURN_001-Q01Supp01Atch04 (Utility Procedure TD-4011P-01– Gas Operations Asset Management Systems Risk Management), Appendix 1. Identified and evaluated risks are documented in the risk register see GTS-RateCase2015_DR_ TURN_001-Q01Atch03CONF. Mitigation programs are: 1) Identified by Asset Family in the asset management plans, see GTS-RateCase2015_DR_ TURN_001-Q01Atch06 through Atch11 (Asset Management Plans), Section 3; 2) Summarized in Session D (GTS-RateCase2015_DR_ TURN_001-Q01Atch04); and 3) Mitigation programs are presented in Session 1, see GTSRateCase2015_DR_TURN_001-Q01Atch20. The final execution plan is presented in Session 2 (GTS-RateCase2015_ DR_TURN_001-Q01Atch21. For a description of the process used to rank mitigation programs in developing the executable investment plan, see GTS-RateCase2015_DR_TURN_001-Q01Atch13 (Gas Operations Investment Planning.

Evaluation Criterion	Related PG&E Process
	Please see the Asset Management Plans (GTS-RateCase2015_DR_TURN_001-Q01Atch06 through Atch11CONF), Section3, for an evaluation of the type of data available, the data required and plans to acquire that data for each Asset Family.
7. Communication and consultation with both internal and external stakeholders must take place in support of the risk-informed resource allocation process.	In 2013, the governing process for risk-informed resource allocation was the Governance and Sanctioning Committee. Over the course of 2013, this Committee comprised of internal stakeholders met multiple times. Additionally the output of that Committee's work was shared with the Gas Operations management team (see GTS-RateCase2015_DR_TURN_001-Q01Atch18CONF for an example). Additionally, Gas Operations retained outside experts formerly associated with the National Transportation Safety Board to review the quality of the overall investment planning process. These experts met periodically with Governance and Sanctioning Committee Members and senior gas leadership to review progress. Finally, Gas Operations created an external advisory committee, comprised of industry experts, that reports directly to the Senior Vice President of Engineering, Construction and Operations. Communication with employees generally around the resource allocation process takes place during annual Extended Leadership meetings, at the monthly Keys to Success Meetings for Director-level leadership, and by informal discussions between leaders and their units. PG&E is communicating and consulting with external stakeholders concerning its risk-informed resource allocation process through this 2015 GT&S rate case as well as CPUC Rulemaking R.13-11.006.

8. An operator must subdivide its system into segments defined to include pipe or equipment having uniform characteristics affecting risk, and must verify that the data on these characteristics is complete, accurate and up-to-date.	As described in Chapter 2, PG&E has divided its natural gas assets into Asset Families. See GTS-RateCase2015_ DR_ORA_007-Q04Atch01 for a copy of the Gas Ops Asset Management Strategy and Objectives. This document shows how the Gas assets are divided into segments or families, with uniform characteristics affecting risk and assesses data quality for those assets. See also GTS-RateCase2015_DR_ORA_019-Q08Atch01, the annual Gas Asset Strategic Review, which includes an assessment of data (quality and quantity) for each asset family. Finally, the Asset Management Plans (GTS-RateCase2015_DR_ TURN_001-Q01Atch06 through Atch11CONF) provide an additional level of detail for the characteristics of the assets that comprise each asset family and the information and data that is available and needed to manage

Evaluation Criterion	Related PG&E Process
	the assets within each family.
9. When data, model or asset condition uncertainties contribute to significant uncertainty in its risk characterization, an operator must identify and implement means to reduce these uncertainties, and must evaluate the impact of these uncertainties on the RCMs proposed in its risk case.	The Asset Management Plans (GTS-RateCase2015_DR_ TURN_001-Q01Atch06 through Atch11CONF) assess the data available and data needs for each asset family. When data is not available to develop mitigations, subject matter expertise is used instead. Mitigations are monitored and measured, but at this time, PG&E does not evaluate the impact of the uncertainties on the mitigation measures. Section D GT&S 2015 prepared testimony, Table 11-3 lists a number of projects that address data and modeling needs from improving situational awareness during emergencies through enhanced control room applications to strengthening the documentation associated with "as-built" asset records. PG&E's 2015 GT&S testimony identifies additional programs to improve asset condition knowledge. An example can be found on page 6-25, to increase data quality, accessibility and completeness in measurement and control assets.

10. All individuals performing activities in support of the risk-informed resource allocation process must have the knowledge and experience needed to perform their function.	PG&E ensured that its risk management, investment planning and asset family owner positions are staffed with people who have the knowledge and experience to perform their function. Where appropriate, this involved hiring from outside the company, such as Gas Operations' Vice President of Financial & Resource Management and Gas Operations' Director of Investment Planning. In addition, Utility Standard TD-4004S (GTS-RateCase2015_DR_ORA_023-Q06Atch02CONF) ensures that the Asset Family Owners have appropriate technical competence.

PG&E did not modify or change any of the criteria.

c. PG&E did not make any changes to its 2015 GT&S filing as a result of the 2014 General Rate Case (GRC). However, as described in Chapter 1 and 2, PG&E presented the 2015 GT&S Application differently than it presented prior GT&S filings due to PG&E's revised approach to managing risk, which takes into consideration the changing regulatory expectations and environment and input from other stakeholders, including the Commission.

GTS-RateCase2015_DR_ORA_023-Q07

PG&E Data Request No.:	ORA_023-07		
PG&E File Name:	GTS-RateCase2015_DR_ORA_023-Q07		
Request Date:	March 12, 2014	Requester DR No.:	ORA-GT&S-23
Date Sent:	April 1, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:		Requester:	Nathaniel Skinner

SUBJECT: RISK REGISTER

QUESTION 7

PG&E provided a worksheet with a tab containing "Summary Risk Scores" as part of TURN_001_Q01Atch03CONF. The following questions pertain to the information reflected in that table.

a. For each item, please provide a table that contains, the Asset Family, Risk ID, Risk Name / Description / Scenario, and Risk Matrix Score. Please provide the following additional columns:
   i. If the risk identified is new to the 2015 GT&S, from the PSEP process, or predates 2011;
   ii. Approximately how many people are currently at risk, and how many will be at risk at the end of 2017;
   iii. How much capital is needed in 2015-2017 to address the risk;
   iv. How much expense is needed in 2015-2017 to address the risk;
   v. By what year this risk is expected to be mitigated;

b. For Risk ID's TRA3, TRA4, DMS1, MC1, and STO16:
   i. If the Commission adopts the programs and projects PG&E is requesting in the 2015 GT&S, what change in this risk matrix should be seen for the next GT&S? Please provide a qualitative description, and then a summary risk scores spreadsheet that would compare the current summary with what the summary would look like in 2018 if all projects and programs proceed as expected.

ANSWER 7

a. The Risk Register provided in TURN_001_Q01Atch03CONF represents the work product of PG&E's risk ranking process for its 2013 Risk Management process, and as noted, the tab "Summary Risk Scores" in the workbook provides the information requested (Asset Family, Risk ID, Risk Name/Description/Scenario, and in Column

N, the Risk Score). We did not collect the additional information in the manner requested in question (a). Nonetheless, please see the following responses:

i. While the risks posed by the various threats to PG&E's natural gas transmission assets generally have not changed in nature over time (see, e.g.. the threats described in ASME B31.8S attachment GTS-RateCase2015_DR_SCGC_001-Q06Atch01), PG&E evaluated its risks across the asset portfolio using the Risk Management process developed in the 2012-2013 time period. See the 2015 Gas Transmission and Storage (GT&S) Rate Case testimony at Chapter 2, Pages 2-10 through 2-17. Accordingly, while the threats and risks are not new, the manner in which the risks are documented and the way the portfolio of work is developed is new.

   The connection of the work proposed in the 2015 GT&S rate case to the Pipeline Safety Enhancement Plan (PSEP) is discussed in Chapter 2, Safety and Risk Management, page 2-25 and Chapter 4, Asset Family – Transmission Pipe, pages 4-12 through 4-14. The decision on which work to perform in PSEP was made with the best information and analysis available at the time using decision trees – rather than the current risk ranking process.

ii. PG&E did not evaluate the number of people affected per threat for each asset family in the Risk Register. PG&E's goal is to reduce the risk for everyone living or working near PG&E's assets. Where appropriate, PG&E uses the total occupancy count (TOC) to help prioritize the order in which work will be performed to yield earlier risk reduction for as many people as possible. See Chapter 2, Safety and Risk Management, pages 2-22 through 2-24. In addition, for some proposed transmission pipeline programs, such as the in-line inspection (ILI) program, PG&E was able to identify specific percentages of populations within the potential impact radius for which ILI is intended to reduce risk posed by threats addressed by ILI (see Chapter 4A, Transmission Integrity Management Program and Emergency Response, page 4A-11).

iii. PG&E's 2015 GT&S rate case forecast provides the amount of capital and expense necessary to reduce the risk profile of its natural gas transmission system with the most risk reduction possible in the shortest amount of time given the resource and execution constraints present, including the need to continue to deliver gas while performing the work. A summary of how each program addresses the specific threats and mitigates risk arising from those threats can be seen in Chapter 2, page 2-20, Figure 2-2.

iv. See answer (iii) above.

v. Chapters 2, 4, 4A, 4B, 5, 6, 7 and 8 of the 2015 GT&S Rate Case describe the proposed mitigation proposals that address the various threats, and in some instances, detail the trajectory of the expected risk reduction over the

rate case period and beyond. It is not possible to predict a specific year by which a risk will be mitigated. As described in Chapter 2, Safety and Risk Management, on pages 2-16 and 2-17, PG&E's proposed mitigation programs are intended to reduce risk to an appropriate level taking into consideration system and resource constraints.

b. For Risk ID's TRA3, TRA4, DMS1, MC1, and STO16:

Because of the evolving nature of the relative risk ranking in the Risk Management processes, along with the emergent nature of information that drives risks, it is not always possible to predict or measure the risk reduction that will result from the mitigation measures presented in this rate case. At this time, PG&E's tools cannot quantitatively measure the risk reduction.

In some cases, Column W of the Risk Register (see GTS-RateCase2015_DR_TURN_001-Q01Atch03CONF) provides a qualitatively developed estimation of the risk reduction from mitigation measures based on available information and understanding at that time.

GTS-RateCase2015_DR_ORA_040-Q04

PG&E Data Request No.:	ORA_040-04		
PG&E File Name:	GTS-RateCase2015_DR_ORA_040-Q04		
Request Date:	May 19, 2014	Requester DR No.:	ORA-GT&S-40
Date Sent:	June 3, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Nathaniel Skinner

SUBJECT: FOLLOW UP TO 2014 SESSION D, GAS OPERATIONS

The questions below all refer to materials from PG&E's response to ORA-019-Q07Atch02.

QUESTION 4

Page 16, which discusses catastrophic failures, identifies many cases where PG&E has large levels of unidentified risks versus the total risk miles. Where PG&E has unassessed risk miles, what assumptions did PG&E make to come to the conclusion that there are significant safety risks in relation to the total risk miles?

ANSWER 4

For this question, PG&E notes that the category of "unassessed risk miles" pertains to the threats of External Corrosion, Internal Corrosion, Weather Related & Outside Forces – Land Movement, and Third Party/Mechanical Damage.

The total risk miles for External Corrosion (TRA1) and Third Party/Mechanical Damage (TRA6) is based on total miles of pipe in Class 3 and 4 or in Class 1 and 2 High Consequence Areas (HCAs) where the risk is identified as active according to PG&E's Transmission Integrity Management Program (TIMP) threat identification process. For the risks of Internal Corrosion (TRA8) and Weather Related & Outside Force – Land Movement (TRA12), there is a missing definition on Page 16. The definition of total risk for these risks is total miles of pipe in PG&E's Transmission pipeline system where the risk is identified as active according to the TIMP threat identification process because these risk scenarios in Session D include failures that are less impactful than TRA1 and TRA6.

For the Session D process, PG&E identified the "unassessed risk miles" safety impact by evaluating the possibility of rupture of the transmission pipeline due to these risks resulting in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damages and/or significant environmental damage. The remainder of the "total risk miles" present a lower likelihood of failure because they have been assessed using 49 Code of Federal Regulations (CFR) 192 Subpart O assessment methods.

GTS-RateCase2015_DR_ORA_040-Q10

PG&E Data Request No.:	ORA_040-10		
PG&E File Name:	GTS-RateCase2015_DR_ORA_040-Q10		
Request Date:	May 19, 2014	Requester DR No.:	ORA-GT&S-40
Date Sent:	June 3, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Terry White	Requester:	Nathaniel Skinner

SUBJECT: FOLLOW UP TO 2014 SESSION D, GAS OPERATIONS

The questions below all refer to materials from PG&E's response to ORA-019-Q07Atch02.

QUESTION 10

Please provide an excel table that contains the values and calculations to derive the "current residual risk score" for the 2013 top 20 risks and the 2014 top 20 risks.

ANSWER 10

The 2013 top 20 risks are in Appendix 1 of the 2013 session D materials which are found in GTS-RateCase2015_DR_ TURN_001-Q01Atch04 pages 26-32. The current residual risk score values for the 2013 risks can be found in Column N, labeled "Matrix Risk Score" of tab "Summary Risk Scores" in the excel table GTS- RateCase2015_DR_TURN_001-Q01Atch03CONF.

The current residual risk score values for the 2014 risks can be found in the excel table GTS-RateCase2015_DR_ORA_040-Q10Atch01. The calculations to derive the 2013 and 2014 scores can be found in GTS-RateCase2015_DR_ORA_040-Q10Atch02 and GTS-RateCase2015_DR_ORA_040-Q10Atch03 respectively.

GTS-RateCase2015_DR_ORA_040-Q10
Attachment 1

Session D '14 Ranking	Asset Family	Risk Name	Risk Descriptions	Residual RISK SCORE
1	Transmission	TRA1 - Catastrophic Pipeline Failure - External Corrosion (System Safety)	Rupture of transmission pipeline due to external corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damages and/or significant environmental damage.	1094
2	Transmission	TRA3 - Catastrophic Pipeline Failure - Welding / Fabrication Related - Pre-1962 Construction with Land Movement (System Safety)	Circumferential rupture of vintage construction pipe (pre-radiographic pre-1962 girth welds, wrinkle bends, dresser couplings, miter bends, etc.) in known regions of geo-hazards and localized landslide zones may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	1092
3	Transmission	TRA8 - Catastrophic Pipeline Failure - Internal Corrosion (System Safety)	Rupture of transmission pipeline due to internal corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage .	810
4	Transmission	TRA4 - Catastrophic Pipeline Failure - Manufacturing Related Defects - Older Seam Types (System Safety)	Longitudinal rupture of transmission pipe with specific seam types (low frequency ERW, AO Smith, lap weld, flash weld, butt weld or pre-1990 spiral) may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	808
5	Transmission	TRA12 - Catastrophic Pipeline Failure - Weather Related & Outside Forces - Land Movement (System Safety)	Pipeline failure due to land movement associated with seismic activity, weather events, or other geo-hazards (e.g levees) may result in the uncontrolled flow of gas that can lead to impact on public or employee safety, prolonged outages, property damage.	806
6	Shared/Common	Cyber Security	An intentional/unintentional loss of control of information and systems used for gas and electric operations (e.g., SCADA, plant networks, trading, etc.) and business operations (e.g., finance, human resources, back office, etc.) may result in: *Life safety events *Operational reliability impacts *Privacy and Intellectual Property Theft *Revenue and reputation loss	323
7	Transmission	TRA6 - Third Party / Mechanical Damage (System Safety)	Rupture of transmission pipe due to mechanical damage by 3rd party may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage.	312
8	Distribution	DMS8 - Excavation Damage - Cross Bore (System Safety)	Third party sewer clearing may result in damage to distribution pipeline, loss of containment, migration of gas with ignition leading to significant property damage or public safety issues.	310
9	Distribution	DMS5 - Material or Weld - Plastic (System Safety)	Aldyl-A pipe material failure may result in loss of containment (body of pipe crack), gas migration and ignition leading to significant property damage or public safety issue.	308
10	Distribution	DMS1 - Excavation Damage, Third Party - Rupture At-Fault due to mismarking by PG&E (System Safety)	Damage to gas distribution facilities from a third party (At-Fault) may result in loss of containment leading to significant property damage or public or employee injury or fatality.	308
11	Storage	STO16 - Pipeline-Internal Corrosion-Erosion (System Safety)	Rupture of pipeline due to internal corrosion and/or erosion may result in loss of containment, and/or uncontrolled gas flow that may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	252
12	C&P	CP6 -Incorrect Operations (System Safety)	Failure or malfunction of critical compression or storage processing equipment may result in reduced transmission capacity or storage withdrawal capacity for cold winter day (CWD), reduced equipment life, and potential loss of containment.	246
13	C&P	CP5 - Manufacturing Defects - Pipe Quality (System Safety)	Loss of containment or reduction in operating pressure due to pipe of unknown or suspect quality (Topock, Hinkley, and station side of Kettleman) or defect resulting from poor manufacture or design practices.	246
14	C&P	CP20 - ThirdParty/Mechanical Damage - Cyber Security (System Safety)	The risk of unauthorized operations of IT, control systems (SCADA) and process control may result in potential safety impacts, loss of service and reliability. - Cyber Security	245
15	Capacity Planning	Failure to Meet Core Customer Design Standard (Abnormal Peak Day)	The risk of not meeting core customer demands as part of the APD design criteria could result in uncontrolled outages which may lead to gas leakage into customer homes and potential explosions.	243

		Seismic	The occurrence of a large-magnitude earthquake in PG&E's service territory that may result in pipeline rupture, station damage, equipment damage/failure and damage to/loss of critical electric and telecommunications infrastructure serving facilities, and/or flooding that could cause a gas release or loss of pressure and lead to significant impact on worker and public safety, reduced service and/or reliability, and hinder timely response to emergency conditions or timely restoration of gas and electric utility service.	**241**
16	M&C	MC32 - Weather & Outside Forces - Seismic/Flooding (System Safety)	The risk of failure of a station to perform its pressure control function from flooding or seismic event causing downstream under or over-pressure events -	**241**
17	Distribution	DMS40 - Records Management	The risk of not having an effective records management program may result in the failure to construct, operate and maintain a utility system safely and prudently. NOTE: This represents Gas Operations' Records Management risk score.	**238**
18	Transmission	TRA17 - External Corrosion - Atmospheric Corrosion (System Safety)	Failure in above ground transmission pipe due to atmospheric corrosion and/or thermal expansion/contraction (on spans) may result in loss of containment that can lead to impact on public or employee safety, outages, property damages.	**236**
19	Shared/Common	Risk of Non-Compliance	The risk of not using an effective system of internal controls and processes, as part of the compliance program/framework, may result in cease and desist orders and/or the forced shutdown of critical assets and facilities.	**236**
20	M&C	MC1 - Incorrect Operations - Overpressure Event (System Safety)	The risk of an overpressure event caused by incorrect operation of low pressure distribution assets may result in failure of downstream assets.	**236**

GTS-RateCase2015_DR_ORA_073-Q01

PG&E Data Request No.:	ORA_073-01		
PG&E File Name:	GTS-RateCase2015_DR_ORA_073-Q01		
Request Date:	June 13, 2014	Requester DR No.:	ORA-GT&S-73
Date Sent:	July 1, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Sara Peralta Burke	Requester:	Matthew Karle

SUBJECT: CH. 7 – CORROSION CONTROL

QUESTION 1

In Ch. 7 workpapers, pg. 7-9, PG&E estimates annual expenses for cathodic protection rectifier maintenance. Please provide actual spending for the period 2003-2013 for cathodic protection rectifier maintenance, and the number of rectifier assets monitored in each year.

ANSWER 1

As noted in Chapter 3 and Chapter 7 of PG&E's 2015 Gas Transmission and Storage Rate Case testimony, PG&E redesigned its Major Work Categories (MWC) and Maintenance Activity Types (MAT) in late 2012 to better identify and group the costs of work being performed in Gas Operations. In 2012, corrosion control expense work was combined with other maintenance work in MWC BX. Therefore, the recorded figures listed in the table below represent the work that is directly attributable to cathodic protection rectifier maintenance but do not necessarily capture all of the rectifier maintenance work performed.

Program	2011 Recorded	2012 Recorded	2013 Recorded
Cathodic Protection Rectifier	**-**	**$ 11,443**	**$ 137,942**

The specific number of historical rectifier assets monitored per year is not readily available. However, there are not significant changes each year and the number of rectifier assets monitored each year between 2003-2013 were generally consistent with the asset count of 866 rectifiers identified in the workpapers supporting Chapter 7 on page WP 7-10.

GTS-RateCase2015_DR_ORA_073-Q13

PG&E Data Request No.:	ORA_073-13		
PG&E File Name:	GTS-RateCase2015_DR_ORA_073-Q13		
Request Date:	June 13, 2014	Requester DR No.:	ORA-GT&S-73
Date Sent:	July 8, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Sara Peralta Burke	Requester:	Matthew Karle

SUBJECT: CH. 7 – CORROSION CONTROL

QUESTION 13

Has PG&E performed benchmarking studies relating to any of the functions included within the corrosion control program? Please provide any studies.

ANSWER 13

Yes, PG&E has performed Benchmarking for its Corrosion Control Program. See Attachments GTS-RateCase2015_DR_IndicatedProducers_002-Q016Atch46 and GTS_RateCase2015_DR_IndicatedProducers_002-Q016Atch48 for benchmarking information.

Also, PG&E participates in the American Gas Association (AGA) benchmarking surveys, but the results cannot be shared without the express written permission from the AGA.

In 2014, PG&E has continued the effort to benchmark against industry practices and assess the overall adequacy and health of the corrosion control program by commissioning an outside consulting firm to compare PG&E's internal documentation with practices identified by regulations, other utilities, and industry standards. The report from this work is attached as GTS-RateCase2015_DR_ORA_073-Q13Atch01.

GTS-RateCase2015_DR_ORA_073-Q13
Attachment 1

GTS-RateCase2015_DR_ORA_073-Q13Atch01

Exponent®

PG&E Gas Transmission & Distribution

Corrosion Program Health Assessment

Phase II: Corrosion Control Program Comparison of Best Practice

Revision C

May 2014

Table 1 Modified RAG or "BRAG" status key showing color, associated meaning, and quality metric.

Color	Meaning	Quality Metric
n/a	Not applicable	n/a
Black	Guidance documentation is non-compliant	0
Red	Guidance documentation is minimally compliant and/or minimally aligned with best practices	1
Amber	Guidance documentation is compliant and partially aligned with best practices	2
Green	Guidance documentation is compliant and aligned with best practices	3

Note: For a topic with seven assessed subtopics, the target quality metric is 21. For topics with fewer than seven assessed subtopics (*i.e.*, certain subtopics are assigned n/a indicators), the target quality metric is scaled accordingly. Topic and subtopic quality metrics are presented in terms of a percentage.

Based upon analysis of current guidance documents, the corrosion control program status findings are as follows (Figure 1):

- 15% of the assessed subtopics (10/66) were deemed non-compliant with federal code.
- 65% of the assessed subtopics (43/66) exhibited room for improvement with respect to compliance with federal code and/or alignment with best practices.
- 20% of the assessed subtopics (13/66) were deemed compliant with federal code and aligned with best practices.

Based upon analysis of future guidance documents, the corrosion control program status findings are as follows (Figure 2):

- 8% of the assessed subtopics (5/65) were deemed non-compliant with federal code.
- 63% of the assessed subtopics (41/65) exhibited room for improvement with respect to compliance with federal code and/or alignment with best practices.
- 29% of the assessed subtopics (19/65) were deemed compliant with federal code and aligned with best practices.

Review of future versus current PG&E guidance documents revealed that the number of non-compliant subtopics dropped from 15% to 8% (*i.e.*, 10/66 to 5/65).

Status indicators were quantified via a "quality metric" in order to compare and rank PG&E's corrosion control program health by topic and subtopic. The target quality metric for a given topic and subtopic is 100%. As shown graphically in Figure 3, the following trends were observed with respect to topic (*i.e.*, programmatic) BRAG status:

- Based upon analysis of current guidance documents:
    - General Cathodic Protection (20%) and Alternating Current (AC) Interference (29%) rank lowest in terms of quality metric.

GTS-RateCase2015_DR_ORA_102-Q01

PG&E Data Request No.:	ORA_102-01		
PG&E File Name:	GTS-RateCase2015_DR_ORA_102-Q01		
Request Date:	July 10, 2014	Requester DR No.:	ORA-GT&S-102
Date Sent:	August 1, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Nathaniel Skinner

SUBJECT: FOLLOW UP TO 2014 SESSION D, GAS OPERATIONS AND ORA-040 QUESTION 8.

The questions below all refer to materials from PG&E's response to **ORA-019-Q07Atch02** and **ORA-040**.

QUESTION 1

In response to ORA-040-Q05 and ORA-019 Q07 Atch 02 (p. 16), PG&E provided a list of miles for risk categories TRA1, TRA3, TRA8, TRA4, TRA12, and TRA6.

a) Please provide an updated table, current through June 1, 2014, that lists by risk category the total risk miles and the unassessed risk miles.

b) Please provide a second table, current through June 1, 2014, that provides:

   a. The total miles considered for all six of these risks, and

   b. The total unassessed risk miles.

c) Please provide a narrative that links any changes in those two tables with the materials in the 2014 Session D, the response to ORA-040-Q05, and the current values.

ANSWER 1

a) Please see the table below for total risk miles and unassessed risk miles by risk category, current through June 1st, 2014.

Risk Category	Total Risk Miles	Unassessed Risk Miles	Unmitigated Risk Miles
TRA1 - External Corrosion	1,706	518	
TRA3 - Welding/Fabrication Related - Pre-1962 Construction with Land Movement	66		66
TRA8 - Internal Corrosion	859	~620	
TRA4 - Manufacturing Threat Associated with Older Seam Types	490		148
TRA12 - Weather Related & Outside Forces – Land Movement	1,672	307	
TRA6 - Third Party/Mechanical Damage	1,706	518	

b) Please see the table below for:

a. The total miles considered for all six of these risks. Please note that pipe segments can fall into more than one risk category.
b. The total unassessed risk miles for TRA1, TRA8, TRA12 and TRA6. Please note that pipe segments can fall into more than one risk category and the miles in the table below are reflective of segments that could have been assessed for one risk category but not all, and therefore are still considered unassessed. PG&E considers pipe segments assessed when all applicable threats have been assessed.

Total Miles Considered for All Risks	1,706
Total Unassessed Risk Miles	~620

c) Please see PG&E's response to ORA_040-Q05 for a narrative explanation of the change in unassessed risk miles from the 2014 Session D materials provided in ORA_019-Q07 and the miles provided in ORA_040-Q05.

GTS-RateCase2015_DR_TURN_01-Q01
Attachment 2

Method for calculating weighted risks and determining the Heat Map

In the risk assessment sessions failure scenarios of assets are identified, including an estimation of the likelihood of these failures (LoF) and the scale of the consequences[1].

Distinction is made between 6 consequence categories:

1. Health and Safety
2. Regulatory Compliance
3. Environmental Impact
4. Reliability
5. Reputation
6. Direct Financial Damage

Each of these categories of consequence of failure (CoF) has 7 levels of severity, increasing an order of magnitude for each next level. To be able to compare and weigh the 6 consequence categories, and to avoid translating human safety into monetary values, a dimensionless normalized consequence value is assigned to each level. These values are valid for every category and have been defined in the discussion with the AFO's and McKinsey. The approach taken here is that they differ between each consecutive level a constant factor and the highest level is designated a normalized number of 100.

This results in the following level values[2]:

Level	Value
7	100.0000
6	17.2579
5	2.9784
4	0.5140
3	0.0887
2	0.0153
1	0.0026

Table 1: Normalized values of each of the consequence levels[3].

[1] In fact a worst case of consequence (P95) is determined. This means that 95% of similar accidents have less severe consequences. Only 5% are worse.
[2] These numbers are presented descending; in line with the risk matrix.
[3] The levels in table 1 can be estimated using the following formula: Value = $0.000456 \cdot e^{1.7569 \cdot N}$ (1) in which N is the consequence level.

The likelihood of failure (LoF) is presented as a frequency, which also increases by an order of magnitude for each higher level. The highest frequency is 10 times per year and the lowest is 1/100,000 times per year.

Most failure scenarios have consequences in more than one consequence category. For comparison a weighted scoring method is set by PG&E's ERM department. The weighing factors are:

Consequence category	Factor
Health and Safety	0.3
Regulatory Compliance	0.05
Environmental Impact	0.05
Financial	0.3
Reliability	0.25
Reputation	0.05

Table 2: Weighing factors of the consequence categories.

In the DNV risk assessment approach for each failure scenario 7 quantities are determined[4]:

1. Frequency of occurrence (LoF): (10 per year to 1/100000 per year)
2. Level for Health and Safety (1-7)
3. Level for Regulatory Compliance (1-7)
4. Level for Environmental Impact (1-7)
5. Level for Reliability (1-7)
6. Level for Reputation (1-7)
7. Level for Direct Financial Damage (1-7)

The weighing of the consequence levels has to be done on the basis of the values as mentioned in table 1.

However this results in a dilution due to the weighting factors and to a dissatisfying and contra-intuitive result as the overall risk is lower than the original Health and Safety value. To compensate for this effect, the result is divided by the health and safety weight factor.

E.g. if for a certain event the consequence levels are estimated to be

1. Health and Safety $N_{H\&S}=6$: 17.2579
2. Regulatory Compliance $N_{RC}=4$: 0.5140
3. Environmental Impact $N_{EI}=1$: 0.0026
4. Reliability $N_{Rel}=3$: 0.0887
5. Reputation $N_{Rep}=4$: 0.5140
6. Direct Financial Damage $N_{Fin}=5$: 2.9784

[4] This determination is done in consultation with Subject Matter Experts, including the Asset Family Owner.

The weighted overall consequence is:

Example	Cat.	Consequense Units	Weights (from PG&E)	Adjusted Consequence Units	Avoiding dilution units
$N_{H\&S}$	6	17.2579	0.3	5.1774	17.2579
N_{RC}	4	0.5140	0.05	0.0257	0.085667
N_{EI}	1	0.0026	0.05	0.0001	0.00044
N_{Rel}	3	0.0887	0.25	0.0222	0.073922
N_{Rep}	4	0.5140	0.05	0.0257	0.085667
N_{Fin}	5	2.9784	0.3	0.8935	2.978352
				6.1446	**20.482**

Table 3: The calculation of the weighted risk values.

These results can be put into the overall risk matrix.

Heat Map

The results can also be used to align with the ERM Heat Map (Bubble Chart).
The consequence scale of the Heat Map is from 0 to 5. The result of the risk assessment can be converted to this by applying the following formula:

$$Consequence_{HM} = 2.7706 + 0.40656 * \ln(result_{RA}) \qquad (2)$$

In which $result_{RA}$ is the outcome of the calculation as in table 3.

The probability of the Heat Map runs from 0 to 100. This can be scaled by using the natural logarithm of the LoF, leading to a linear probability distribution:

$$\text{Probability} = 71.42857 + 6.204207 * \ln(LoF) \qquad (3)$$

The following table shows an example of 5 risks and their weighting and the placement in the Heat Map.

	Input									
	Weighting factor	0.3	0.05	0.05	0.25	0.05	0.3	$Value_{Weighted}$	$Prob_{HM}$	$Consequence_{HM}$
	LoF[5]	$N_{H\&S}$	N_{RC}	N_{EI}	N_{Rel}	N_{Rep}	N_{Fin}	Table 3	Formula (3)	Formula (2)
Risk1	0.062	5	1	1	2	5	2	3.50	54.177	3.28
Risk2	0.04	6	1	1	2	4	2	17.38	51.458	3.93
Risk3	0.000008	7	1	1	5	6	3	105.47	0.000	4.66
Risk4	0.0000016	6	2	1	5	5	2	20.26	0.000	3.99
Risk5	0.01	3	2	1	5	4	4	3.17	42.857	3.24

Table 4. Calculation results for the risk matrix and the Heat Map.

[5] If the LoF is less then 1/100,000 it is truncated at that minimum

The plotted results of table 4 are shown in figures 1 and 2.

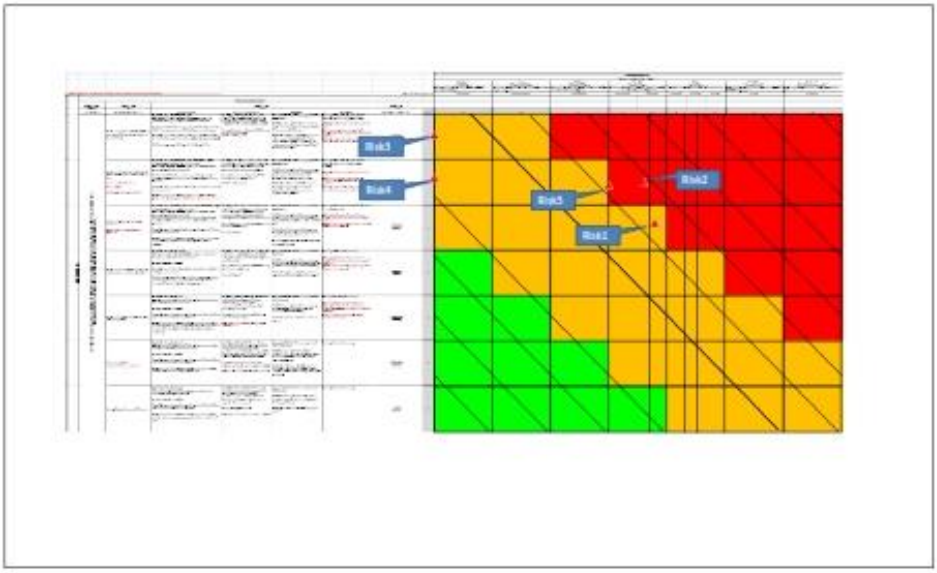

Figure 1. Results in the Risk Matrix

Public Utilities Code Section 451

451. All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.

Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in Section 54.1 of the Civil Code, as are necesary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.

All rules made by public utility affecting or pertaining to its charges or service to the public shall be just and reasonable.

Public Utilities Code Section 963(b)(3)

963. (a) For purposes of this section, the following terms have the following meanings:

(1) "After-meter services" includes, but is not limited to, leak investigation, inspecting customer piping and appliances, carbon monoxide investigation, pilot relighting, and high bill investigation.

(2) "Basic gas service" includes transmission, storage for reliability of service, and distribution of natural gas, purchasing natural gas on behalf of a customer, revenue cycle services, and after-meter services.

(3) "Metering services" includes, but is not limited to, gas meter installation, meter maintenance, meter testing, collecting and processing consumption data, and all related services associated with the meter.

(4) "Revenue cycle services" means metering services, billing the customer, collection, and related customer services.

(b) The Legislature finds and declares all of the following:

(1) In order to ensure that all core customers of a gas corporation continue to receive safe basic gas service, each existing gas corporation shall continue to provide this essential service.

(2) A customer shall not be required to pay separate fees for utilizing services that protect public or customer safety.

(3) It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.

(c) (1) The commission shall require each gas corporation to provide bundled basic gas service to all core customers in its service territory unless the customer chooses or contracts to have natural gas purchased and supplied by another entity.

(2) A gas corporation shall continue to be the exclusive provider of revenue cycle services to all customers in its service territory, except that an entity purchasing and supplying natural gas under the commission's existing core aggregation program may perform billing and collection services for its customers under the same terms as currently authorized by the commission, and except that a supplier of

natural gas to noncore customers may perform billing and collection for natural gas supply for its customers.

(3) The gas corporation shall continue to calculate its charges for services provided by that corporation. If the commission establishes credits to be provided by the gas corporation to core aggregation or noncore customers who obtain billing or collection services from entities other than the gas corporation, the credit shall be equal to the billing and collection services costs actually avoided by the gas corporation.

(4) The commission shall require the distribution rate to continue to include after-meter services and shall authorize sufficient revenues and employee staffing to provide for prompt provision of these services to the public, consistent with the policy developed and implemented by the gas corporation and approved by the commission pursuant to Section 961.

49 Code of Federal Regulations Section 192.467

1. §192.476 Internal corrosion control: Design and construction of transmission line.

(a) *Design and construction.* Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

(b) *Exceptions to applicability.* The design and construction requirements of paragraph (a) of this section do not apply to the following:

(1) Offshore pipeline; and

(2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

(c) *Change to existing transmission line.* When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

(d) *Records.* An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

[72 FR 20059, Apr. 23, 2007]

49 Code of Federal Regulations Section 192.479

1. §192.479 Atmospheric corrosion control: General.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

49 Code of Federal Regulations Section 192.481

1. §192.483 Remedial measures: General.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of §192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

49 Code of Federal Regulations Subpart I
Requirements for Corrosion Control

Subpart I—Requirements for Corrosion Control

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§192.490 Direct assessment.
§192.491 Corrosion control records.

SOURCE: Amdt. 192-4, 36 FR 12302, June 30, 1971, unless otherwise noted.

§192.451 Scope.

(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(b) [Reserved]

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]

§192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

(a) *Converted pipelines.* Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with §192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

(b) *Regulated onshore gathering lines.* For any regulated onshore gathering line under §192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under §192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977, as amended by Amdt. 192-102, 71 FR 13303, Mar. 15, 2006]

§192.453 General.

The corrosion control procedures required by §192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

[Amdt. 192-71, 59 FR 6584, Feb. 11, 1994]

§192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of §192.461.

(2) It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—

(1) For a copper pipeline, a corrosive environment does not exist; or

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a)(2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if:

(1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended at Amdt. 192-28, 42 FR 35654, July 11, 1977; Amdt. 192-39, 47 FR 9844, Mar. 8, 1982; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

(2) Bare or coated pipes at compressor, regulator, and measuring stations.

(3) Bare or coated distribution lines.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.459 External corrosion control: Examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under §§192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

[Amdt. 192-87, 64 FR 56981, Oct. 22, 1999]

§192.461 External corrosion control: Protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

§192.463 External corrosion control: Cathodic protection.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential—

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of appendix D of this part for amphoteric metals.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

§192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by §§192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-35A, 45 FR 23441, Apr. 7, 1980; Amdt. 192-85, 63 FR 37504, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010]

§192.467 External corrosion control: Electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§192.469 External corrosion control: Test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

§192.471 External corrosion control: Test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m^{-3}) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.476 Internal corrosion control: Design and construction of transmission line.

(a) *Design and construction.* Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

(b) *Exceptions to applicability.* The design and construction requirements of paragraph (a) of this section do not apply to the following:

(1) Offshore pipeline; and

(2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

(c) *Change to existing transmission line.* When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

(d) *Records.* An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

[72 FR 20059, Apr. 23, 2007]

§192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months.

[Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§192.479 Atmospheric corrosion control: General.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§192.481 Atmospheric corrosion control: Monitoring.

(a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore	At least once every 3 calendar years, but with intervals not exceeding 39 months
Offshore	At least once each calendar year, but with intervals not exceeding 15 months

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by §192.479.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§192.483 Remedial measures: General.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of §192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§192.485 Remedial measures: Transmission lines.

(a) *General corrosion.* Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-88, 64 FR 69664, Dec. 14, 1999]

§192.487 Remedial measures: Distribution lines other than cast iron or ductile iron lines.

(a) *General corrosion.* Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-88, 64 FR 69665, Dec. 14, 1999]

§192.489 Remedial measures: Cast iron and ductile iron pipelines.

(a) *General graphitization.* Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.

(b) *Localized graphitization.* Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

§192.490 Direct assessment.

Each operator that uses direct assessment as defined in §192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	**Standard**[1]
External corrosion	§192.925[2]
Internal corrosion in pipelines that transport dry gas	§192.927
Stress corrosion cracking	§192.929

[1]For lines not subject to subpart O of this part, the terms “covered segment” and “covered pipeline segment” in §§192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.

[2]In §192.925(b), the provision regarding detection of coating damage applies only to pipelines subject to subpart O of this part.

[Amdt. 192-101, 70 FR 61575, Oct. 25, 2005]

§192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

[Amdt. 192-78, 61 FR 28785, June 6, 1996]