Additional information for Revised Risk Analysis Methodology:

As stated in the status update, PG&E completed the implementation of a revised risk analysis methodology (*Attachment P-11-29 Risk Management, RMP-16, Rev 0)*. In addition to the procedures that already existed for external corrosion, third party damage, design/material (including manufacturing and construction threats), incorrect operations, weather, and outside force and equipment threats, PG&E made the following changes to threat identification procedures:

- Improved procedures to create separate and improved procedures for manufacturing and construction threats
- Created new procedures for internal corrosion and stress corrosion Cracking threats
- Created new procedure addressing interacting threats (including cyclic fatigue)

This new information and input will be used in PG&E's integrity management program and will support the planning and implementation of the overarching Gas Safety Excellence plans being developed following the PAS 55 Standard.

PACIFIC GAS AND ELECTRIC COMPANY

GAS ENGINEERING & OPERATIONS
INTEGRITY MANAGEMENT

PG&E

Risk Management Procedure

Procedure No. RMP-01
Revision 7

Gas Transmission Integrity Management Program
for PG&E and Standard Pacific Pipeline Inc.

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0	11/13/01	Initial Issue	Redacted	Redacted	Redacted
1	1/8/03	Revised as shown			
2	6/29/04	Revised as shown			
3	11/16/04	Revised as shown			
4	6/9/05	Revised as shown			
5	10/31/05	Revised as shown			
6	1/10/11	See Change Form			SEBE

Rev No	Date	Description	Prepared by	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
7	3/26/12	See Change Form	Redacte	SEBE	NA	SLHB	RIT4

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1.0 PURPOSE

The purpose of this procedure is to provide a process for maintaining the Risk Management Program (RMP) and complying with the requirements for risk calculations as part of PG&E's Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) which are prescribed in RMP-06 and RMP-15, respectively.

2.0 SCOPE

2.1 General

The Risk Management Group is responsible for managing risk within the scope of this procedure. The Risk Management Group shall establish the risk of each pipeline facility by utilizing industry and regulatory accepted methodologies appropriate for PG&E's facilities. The Risk Management Group shall apply this procedure, and as appropriate, partner with the Pipeline Engineering, the System Integrity Group and other internal organizations to apply this procedure in an effort to manage risk.

Risk information shall be communicated to management and other appropriate PG&E personnel for project planning, risk mitigation, inspection planning, and 7 regulatory reporting. Per RMP-06, risk for each pipeline segment shall be calculated annually or as required by RMP-15.

2.2 Transmission

This procedure is applicable to all PG&E's covered (as defined by RMP -6 and RMP-08) and non-covered transmission and piping segments drawn in GIS. This procedure does not cover gas gathering facilities.

Risk values for non covered equipment or appurtenances, including drips, blow downs, stubs, crossties, dual feeds or other equipment or appurtenances are not calculated, as these appurtenances will take on the risk value calculated for its associated mainline pipe pursuant to PHMSA IM FAQ 84. .

2.3 Distribution

This procedure is applicable for all PG&E distribution piping operating above 60 psig for the assessment of risk per the DIMP program.

3.0 INTRODUCTION

The risk management process is a process of integrating data to calculate risk, developing risk mitigation plans to continually reduce risk, and monitoring risk to accommodate changes in the factors that affect risk. PG&E applies this process to all pipelines system-wide and annually considers assessments or mitigation needed to ensure the on-going integrity of all pipelines.

RMP-01 is referenced to calculate the overall risk; the combination of the likelihood of failure due to four of the basic pipeline threats (external corrosion, third party, ground movement, and design/materials, including welding and fabrication related risks) and the consequence of failure.

Historically, IC and SCC likelihoods were considered for inclusion into the risk model but ultimately were not included because they affected a small portion of the system. The rationale for this decision is listed in Section 9. PG&E has recently decided to add these items to its risk model and that work is in progress. As an interim measure, Transmission segments with the potential for these threats are scheduled as "high risk." 7

PG&E has considered Equipment and Incorrect Operations risks to be equivalent for all transmission segments and therefore has not added these threats into the relative risk scoring model. Work is currently underway to identify a means to develop a gradient scoring methodology for these threats.

An inventory of all the pipeline design attributes, operating conditions, environment (e.g., structures, faults, etc.), threats to the structural integrity, leak experience, and inspection findings must be developed and maintained. Risk must be calculated based on an immense inventory of assembled attributes. The risk values need to be reviewed and criteria for acceptance established, risk mitigation plans developed, budgeted and completed, and conditions monitored to update criteria, risk values, and mitigation plans, as necessary, to accommodate new information. (New information could include new damage prediction models, changes to population in proximity to a pipeline, changes to system operating characteristics which could effect safety margin, damage accumulation, the number of customers out of service, or gas load, new seismic or environmental hazard identification, inspection findings as they relate to the physical condition of the pipe or the systems needed to protect the pipeline or component from damage or degradation, or changes in the potential for third party damage.)

Because threats to the pipeline and consequences of a failure change with time, the process of monitoring and adjusting risk mitigation plans is an ongoing process. The risk management process is a methodology utilizing pipeline characteristics (physical and environmental), qualitative risk assessment, quantitative risk analysis, and decision-risk analysis methods to determine the risk to each of PG&E's pipeline facilities. The process follows these basic steps: 7

- Accumulate facility design attributes, existing condition, potential threats, and failure consequence,

- Determine Likelihood of Failure (LOF) for each pipeline segment,
- Determine Consequence of Failure (COF) for each pipeline segment,
- Calculate risk for each pipeline segment based on the Likelihood of Failure and the Consequence of Failure,
- Develop a system wide risk mitigation strategy,
- Propose and prioritize rehabilitation projects or inspections based on the damage mechanism, threat, and risk, and finally,
- Monitor and adjust the process, as necessary, to incorporate changes in technology, changes in information, or changes in code or regulatory requirements.

4.0 Roles and Responsibility

Specific responsibilities for ensuring compliance with this procedure are as follows:

Title	Reports to:	Responsibilities
Manager of Integrity Management	Director of Transmission Integrity Management	• Review and approve selection of Steering Committee Chairperson and membership
Integrity Management Program Manager	Manager of Integrity Management	• Supervise completion of work (schedule/quality) • Monitor compliance to procedure – take corrective actions as necessary. • Assign qualified individuals • Ensure Training of assigned individuals
Steering Committee Chairperson (Risk Management Engineers)	Integrity Management Program Manager (except for TP Steering Committee – chairperson reports to Manager System Integrity)	• Arrange meetings. • Review procedure with committee per RMP-01 • Provides meeting minutes • Ensures action items are completed.
Steering Committee Members (Subject Matter Experts)	Various	• Attend meetings as requested by Steering Committee Chairman. • Provide review and direction to procedure.
Risk Management Engineers	Integrity Management Program Manager	• Perform calculations per procedure.

5.0 Training and Qualifications

See RMP-06 and RMP-15 for qualification requirements. Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training:	How Often
Integrity Management Program Manager	Procedure review of RMP-01	• Upon initial assignment • Once each calendar year.
Steering Committee Chairperson	Procedure review of RMP-01	• Upon initial assignment • At least once each year the committee meets • As changes are made to the procedure.
Steering Committee Members (Subject Matter Experts)	Steering Committee requirements of RMP-01.	• At least once each year the committee meets
Risk Management Engineers	Procedure Review of RMP-01 and RMP-06.	• Upon initial assignment • Once each calendar year. • As changes are made to the procedure.

6.0 RISK DETERMINATION

6.1 ***RISK*** shall be defined as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF).

[RISK = LOF X COF] *(Equation 1)*

In general, the source of information used to calculate risk shall be obtained from PG&E's Geographical Information System (GIS). Exceptions are noted within RMP procedures. There are also special cases where updated information is made available from other sources (such as from Pipeline Engineers, In-Line-Inspection (ILI) reports, Corrosion Engineers, or District Personnel).

6.2 ***CALCULATION METHODOLOGY:*** A relative risk calculation methodology shall be used to establish risk. Risk will be calculated per this procedure for all pipeline segments within the scope of this procedure. A pipeline segment shall be defined as the length of contiguous pipeline with the same piping specification, class location, and Integrity Management HCA designation (Pipe segments are as shown in GIS.) The method used to calculate risk shall be based on an index model and qualitative scoring approach. The scoring shall be based on expert direction from appropriately staffed Steering Committees. For each major component of the integrity management program, a Steering Committee shall be established to provide technical review and input to the program. There are currently five committees covering External Corrosion, Third Party damage, Ground Movement, Design/Materials, and Consequence. Requirements for the Steering Committees are as follows:

6.2.1 The Steering Committees shall be comprised of a minimum of five individuals with expertise in the particular subject matter. It is the responsibility of the Integrity Management Program Manager, with the concurrence of the Manager of System Integrity, to select a range of individuals with knowledge and experience on the subject matter for which they are contributing. A list of the current membership shall be documented and included in RMP File 7.1.

6.2.2 For each steering committee, the Integrity Management Manager, with the concurrence of the Integrity Management Program Manager, shall assign a Committee Chairperson except as noted by RMP-15. The Chairperson is responsible for scheduling meetings, conducting the meeting in accordance with the requirements of this procedure, preparing meeting minutes, preparing necessary supporting material (risk ranked pipelines and applicable GIS themes) prior to the meeting, and making necessary changes to procedures following the meeting. 7

6.2.3 The committees shall meet at least once each year, to review and approve the methodology used to calculate risk and determine if changes are advisable.

6.2.4 At each meeting or at least once every other calendar year, the committee shall review the overall process of risk calculations provided by this procedure, the detailed requirements for conducting the meeting as contained in this section of RMP-01 (because the Consequence Steering Committee is responsible for this procedure, the committee will perform a detailed review), and a detailed review of the requirements of the procedure for which they are providing direction.

6.2.5 At each meeting or at least once each calendar year, the committee shall review, at a minimum the following:

For the Likelihood of Failure Steering Committee: 7
- The output from the risk algorithm
- Relevant performance metrics to the threat

For the Consequence of Failure Steering Committee, the review shall at a minimum consider:
- The output from the risk algorithm 7
- Relevant performance metrics and industry data

In reviewing each of these segments, the committee shall determine if, in the opinion of the committee, the ranking is appropriate or changes in the risk calculation algorithms is required. Consideration shall be made to the relative ranking of the various components used to calculate risk and the need for inclusion of other important information that may not have been included. The review should also consist of integrating all of the relevant (based on the procedure being evaluated) layers and themes in GIS and reviewing the integrated data (not just aggregating the information in a spreadsheet) in determining the validity of the risk algorithms.

Each steering committee will identify the significant attributes that influence the threat's LOF or COF, as appropriate. For each attribute, a percentage weighting will be established or reviewed to identify the factors' relative significance in determining the threat's LOF or COF. Points will be established based on criteria that the committee feels is significant to determining the threat's LOF or COF and the relative severity of failure (leak-before-break vs. rupture). (Negative points may be assigned where current assessments have been made to confirm pipeline integrity and/or mitigation efforts have eliminated or lowered susceptibility to a threat although the total points for a threat will not be less than zero.) Generally, the summation of the percentage weightings for all of the factors within each threat should be 100%. (There may be exceptions to permit the consideration of very unusual conditions.)

6.3 ***LIKELIHOOD OF FAILURE (LOF)*** is the relative measure of the probability that a pipe will fail. Failure, within the context of this procedure, is the breach of the structural integrity of the pipe. The following threat categories shall be used for calculating risk: External Corrosion (EC), Third Party (TP), Ground Movement (GM) and Design/Materials (DM). (As new credible threats are identified as relevant to the determination the LOF, they will be submitted to the Consequence Steering Committee for inclusion into the risk calculations.) Each threat category shall be weighted in proportion to PG&E and industry failure experience. EC is currently weighted 25%, TP shall be weighted 41%, GM shall be weighted 16%, and DM shall be weighted 18%.

$$\boldsymbol{LOF = 0.25EC + 0.41TP + 0.16GM + 0.18DM} \qquad \textit{(Equation 2)}$$ 7

Committees used to review procedures applicable to these threats are as follows:

6.3.1 The algorithm for the threat of External Corrosion (EC) shall be calculated per the direction of the EC Steering Committee as provided in Procedure RMP-02.

6.3.2 The algorithm for the threat of Third Party (TP) shall be calculated per the direction of the TP Steering Committee given in Procedure RMP-03.

6.3.3 The algorithm for the threat of Ground Movement (GM) shall be calculated per the direction of the GM Steering Committee given in Procedure RMP-04.

6.3.4 The algorithm for the threat of Design Materials (DM) shall be calculated per the direction of the DM Steering Committee given in Procedure RMP-05.

6.4 Consequence of a Failure (COF) shall be defined as the sum of the following Consequences Categories: Impact on Population (IOP), Impact on the Environment (IOE), and Impact on Reliability (IOR). Each of the consequence categories shall be weighted in proportion to the perceived impact of a failure. IOP shall be weighted 50%, IOE shall be weighted 10%, and IOR shall be weighted 40%.

COF = [0.50(IOP) + 0.10(IOE) + 0.40(IOR)]FSF *Equation 3*

Where, *IOP = Impact on Population (Section 6.4.1 of this procedure)*

IOE = Impact on Environment (Section 6.4.2 of this procedure)

IOR = Impact on Reliability (Section 6.4.3 of this procedure)

FSF = Failure Significance Factor, which represents the relative likelihood of leak rather than rupture and the existence of Wall-to-Wall conditions which would make the consequences of a leak more severe. The FSF will be taken as 0.5 for pipeline where the MOP is at <20% SMYS and Wall-to-Wall paving conditions are verified NOT to exist and 1.0 for pipelines where the MOP is at ≥ 20% SMYS or where Wall-to-Wall paving conditions exist or have not been verified to NOT exist. In addition, the FSF shall not be taken as less than 1.0 where the following conditions exist:

- *Where the pipeline segment is within 300' of a School, Hospital, or Prison Building unless the outside pipe diameter is less than or equal to 4.5"*
- *Where the pipeline segment is within 300' of a switchyard.*
- *Where the pipeline was installed prior to 1962 and is in an area of ground acceleration greater than 0.5g.*
- *Where the pipeline segment was installed prior to* 7
1962 and is in an area of ground acceleration greater than or equal to 0.2g AND is in an area of unstable soil. (Unstable soil, for the purpose of this definition, is categorized as that identified as

- *having High/Moderate potential for liquefaction or High/Mod potential for landslide.)*
- *Where the pipeline segment has a depth of cover of less than or equal to one foot.*
- *Where the pipeline segment has a MOP of greater than 200 psig, has an outside diameter of greater than or equal to 4.5", and is Class 3.*

The weightings on each of the consequence categories will be reviewed and approved by the Consequence Steering Committee. Points will be scored to the consequences as follows:

6.4.1 Impact on Population (IOP) shall be calculated per the direction of the Consequence Steering Committee. The committee has determined that the factors in A through C of this section are significant for determining the Population Impact of a gas pipeline failure. The IOP contribution to COF shall be the summation of assigned points times the assigned weighting for the following factors:

A) Population Density in Proximity to Pipeline (35% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
Class 1	10	3.5
Class 2	40	14
Class 3	70	24.5
Class 4	100	35

B) Pipeline proximity[1] to a potential area of population concentration (45% Weighting): Points ***are additive*** and will be awarded as follows:

Criteria	Points[5]	Contrib.
Identified Sites[3] that require a Integrity Management Plans: Examples include Hospitals, Schools, Childcare Centers, Retirement Communities, Prisons, Health Treatment Facilities, and Public Assembly Areas such as stadiums, churches, parks, outdoor transit terminals within the Potential Impact Radius[2]	100	45
Railroads, Bart, and Light Rail tracks	30	13.5
Highway[4]	40	18
Commercial Airports[6]	50	22.5
No Feature	0	0

[1] Within 100 Yards or (PIR)

[2] Potential Impact Radius (PIR), (where PIR = 0.69(OD)(√MOP) (in feet)), of Pipeline centerline.

[3] Identified Sites consist of facilities having persons who are confined, are of impaired mobility or would be difficult to evacuate or other identified public assembly areas where 20 or more persons congregate at least 50 days in any 12-month period. A detailed definition is provided in RMP-08.

[4] Highways are Class 1, 2, and 3 roads in GIS
[5] Points shall be awarded once per category. (For example, a pipe segment with two adjacent highways would be awarded 40 points.)
[6] Airports must have a control tower and commercial or military traffic consisting of 1% or more of the total airport traffic.

C) Potential Impact Radius (Ft.) (20% Weighting): Points will be awarded as follows:

$$\text{Points} = 1 + \pi[(0.69)(OD^2 * MOP)^{1/2}]^2(1.3X10^{-5}), \text{ not to exceed } 20$$

6.4.2 Impact on Environment (IOE) shall be calculated per the direction of the Consequence Steering Committee. The committee has determined that the factors in A and B of this section are significant for determining the environmental impact of a gas pipeline failure. The IOE contribution to COF shall be the summation of the assigned points times the assigned weighting for the following factors:

A) Presence of a Water Crossing (20% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
Presence of Water Crossing	100	20
No Water Crossing	0	0

B) Passing through or adjacent* to an Environmentally Sensitive Area (80% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
State or National Park	70	56
Wildlife Preserve	70	56
Navigable Waterway	90	72
Other Protected Area	70	56
No Environmentally Sensitive Area	0	0

* Within 100 Yards or PIR), (where PIR = 0.685(OD)(√MOP) (in feet)), of Pipeline centerline, whichever is greater and unless otherwise noted

6.4.3 Impact on Reliability (IOR) shall be calculated per the direction of the Consequence Steering Committee. The committee has determined that the factors in A though C of this section are significant for determining the reliability impact of a gas pipeline failure. The IOR contribution to COF shall be the summation of the assigned points times the assigned weighting for the following factors:

A) Reliability Impact on Customers served by PG&E in the event of a pipe failure (35% Weighting): Points will be awarded for gas load[1] as follows:

Points = 10 + (Gas Load[1]/500), not to exceed 100.

Unknown Gas Load = 20.

1 Gas Load (MCF/Day) is the higher of an Average Summer Day (ASD) or an Average Winter Day (AWD) as provided by Transmission System Planning. It does not include an Abnormal Peak Day (APD).

B) Number of Customers[1] to experience a gas service outage (55% Weighting): Points will be awarded as follows:

Points = 10 + (Customer Outages[1]/500), not to exceed 100.
Unknown Gas Load = 20.

1 The number of customer outages is provided by Transmission System Planning.

C) Proximity of Critical Facilities (10% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
Liquid Fuel Pipelines[1]	100	10
Other Gas Pipelines[2]	80	8
Electric Transmission Lines[1]	80	8
No Critical Facilities	0	0

1 Within 30 Meters of Gas Pipeline.
2 Within 10 Meters of Gas Pipeline.
3 The distances in footnotes 1 and 2 shown above may be adjusted as appropriate to reflect conditions verified in the field such as precise location and cover.
4 If there are multiple critical facilities, only the facility with the highest points will be counted.

7.0 RISK MITIGATION OF TRANSMISSION FACILITIES

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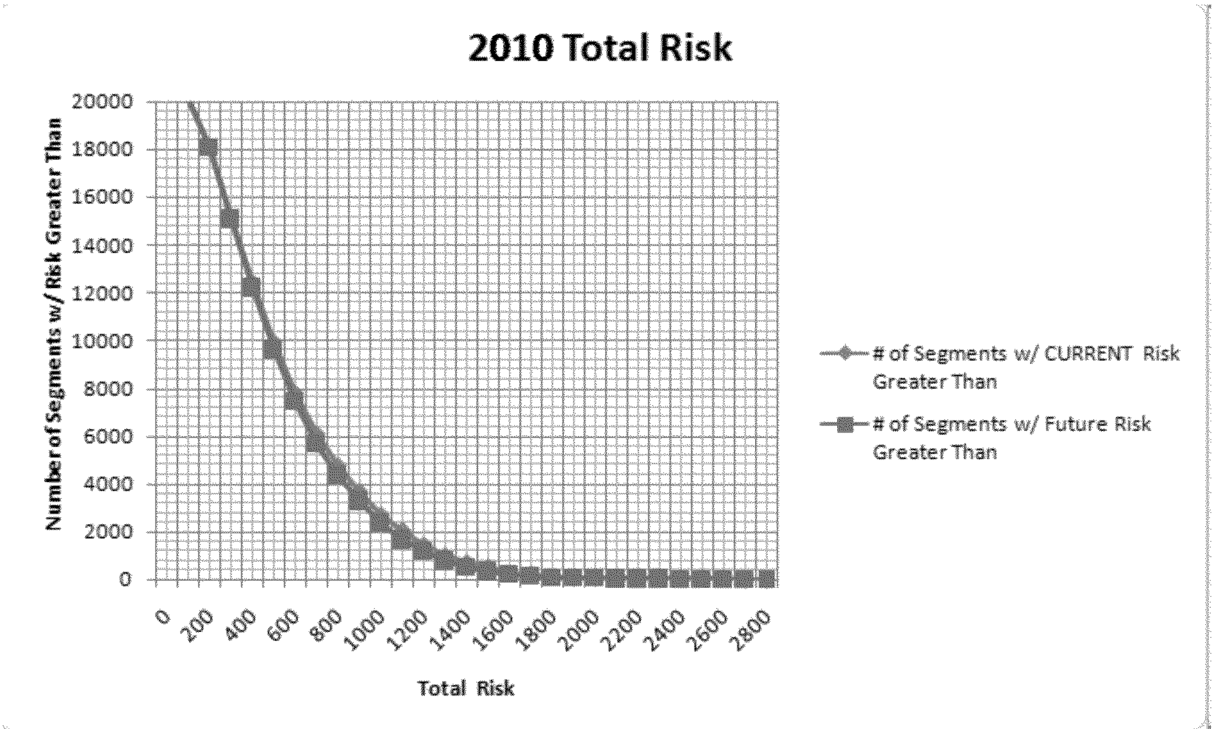
7.1 RISK REVIEW AND ESTABLISHMENT OF TARGET RISK THRESHOLDS

After calculating risk for all pipeline segments, a review of the risk profile is performed with a focus on high-risk pipeline facilities. A target risk threshold is established based on the risk profile and the comparative level of risk necessary to obtain confidence in the structural integrity of PG&E's pipeline system. (Below is a risk profile for 2010.)



Once the threshold is established, high-risk segments are reviewed for factors that are significant risk drivers. From these, pipelines are selected for investigation, and mitigation efforts are then proposed to address the significant risk drivers. Because any pipeline failure, regardless of the consequences, is highly undesirable, it may also be prudent to select a certain number of pipelines for investigation based on a high LOF. Consideration as to the number and selection of pipelines to investigate would include the relative LOF, threat type, past risk mitigation efforts, and confidence in COF values.

Depending on the risk driver, mitigation efforts could include one or more of the following inspections or tests to verify assumptions made in the risk calculation and integrity of the pipeline,

- Reduced operating pressure,
- Recoating
- Modification, alteration, or replacement of pipe or protective features,
- Additional Public Education as part of the PSIP Program discussed in Section 7.5 of this procedure or by additional line markers,
- Verification or modification of the consequences of a failure.

The following table provides an example of considerations that may enter into a decision process in developing a risk mitigation strategy:

Mitigation	Risk Attributes
In Line Inspection (ILI)	EC Threat, operating at or over 30% SMYS, installed prior to 1971 and can be piggable.
Corrosion Survey	Pipelines that have a high consequence, high or medium likelihood of LOF TP, or LOF EC.. Can also be used to determine if ILI is needed.
Leak Survey	Pipelines that are operating below 30% SMYS and are not high LOF EC or LOF TP
Pressure Test	Pipelines operating at or above 40% SMYS with high likelihood of failure due to design/material issues, and have not been hydro tested.
Pipe Replacement	Pipelines with high likelihood of failure that were installed prior to 1950 and cannot be economically inspected using other methods.
Line Marking	High LOF TP, low/medium likelihood for other threats.
Landowner Notification	High LOF TP, low/medium likelihood for other threats

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(Note: The risk mitigation efforts discussed in this section apply to pipeline segments not covered by RMP-06. Mitigation activities for covered pipeline segments shall be performed per RMP-06).

Risk and IMA Risk (discussed in section 9.0 of this procedure) are reported in the Integrity Management Plan for each pipeline segment. 7

7.2 INSPECTION/TESTING

An effective tool in risk management is inspections and testing. Due to the serious consequences of a pipeline failure, conservative assumptions are necessarily made as to the status of a pipeline when conditions are not known. It is very common to perform an inspection and test and verify that the condition of a pipeline is much better than assumed. The type of inspection or test specified is dependant on the threat and how the damage is manifested.

7.3 PROJECT PLANNING

RMP involvement in the Budget Planning Process also provides opportunities to reduce risk. Therefore, for each proposed project in the annual budget that is risk driven, a risk reduction calculation is performed when requested so that an evaluation can be made as to the risk reduction benefits of the project. Often times, a project benefiting the operating capacity or operating efficiency will also reduce risk and based on a combined benefit will be the most cost effective project.

7.4 REHABILITATION

The RMP Project will propose such projects, as are necessary to establish and maintain an acceptable risk profile. In addition, the RMP will also support and propose other projects that will reduce risk where there are opportunities to justify projects based on reducing risk and reducing maintenance or operation costs. As projects are submitted for budgeting, they should be prioritized. Following is one prioritization strategy that could be used:

Priority	Attributes
1	High Consequence Area (HCA) Multiple Significant Risk Drivers High Total Risk (> 1500) >= 30% SMYS
2	Same as 1 except: % SMYS < 30% or Single Risk Driver > 30% SMYS in HCA
3	High Threat Risk or Total Risk (>1800) Single Risk Driver > 30% SMYS or < 30% SMYS w/IMA
4	High Likelihood Threat or Total Risk Med/Low Consequence (Not HCA) < 30 % SMYS

Projects proposed to reduce risk shall be monitored to ensure that a reduction in risk has been obtained and that the results have been captured in the risk values.

7.5 PUBLIC SAFETY INFORMATION PROGRAM (PSIP)

An effective Public Safety Information Program is a key component of any Risk Mitigation Program. PG&E's PSIP program is documented in RMP-12.

**Note: All risk mitigation activities related to distribution facilities are performed per RMP-15. 7

8.0 RMP MAINTENANCE

8.1 FACILITY UPDATE

In general, the source of information used to calculate risk shall be obtained from PG&E's Geographical Information System (GIS). Exceptions are noted within the applicable procedures. There are also special cases where updated information is made available from other sources (such as from pipeline engineers, In-Line-Inspection (ILI) reports, or Corrosion Engineers).

Changes in facility properties shall be incorporated into the Risk Calculations at least annually. Examples of facility properties include location, material properties, coating, operating status, cover, pipe specification, and structures near the facility.

8.2 HAZARD UPDATE

RMP will monitor industry experience, as well as PG&E experience to identify trends in threat prediction, mitigation effectiveness, and advances in inspection and risk management technology and adapt the program to new information as necessary to keep the program current and robust.

Data bases necessary for making accurate risk evaluations will be maintained and updated as necessary to ensure hazard information in current. Information necessary to accurately determine and track risk will also be updated as follows:

Threat	Update Interval
Third Party Dig-Ins	As Submitted, Annually – Into Risk Calculations
Leak Reports (EC, DM)	As Submitted, Annually - Into Risk Calculations
Seismic (Fault Crossings)	5 years (Per Procedure RMP-04)
Seismic (Vertical or Horizontal Ground Acceleration)	5 years (Per Procedure RMP-04)
Slope Stability	5 years (Per Procedure RMP-04)
Liquefaction	5 years (Per Procedure RMP-04)
Water Crossing	10 years

8.3 CONSEQUENCE UPDATE

RMP will monitor industry experience, as well as PG&E experience to identify trends in consequence prediction and mitigation effectiveness and adapt the program to new information to keep the program current and robust.

Databases necessary for making accurate risk evaluations and support Integrity Management activities, as required by RMP-06 and RMP-15, will be maintained and updated as necessary to ensure consequence information is current. The following Geographic information will also be updated as follows:

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Consequence	Update Interval
Electric Transmission (internal)	As internal updates are processed
Other (Foreign) Pipelines/ Facilities	As made available
Water Crossing (Navigable Waterways)	As updates become available.
Land Base*	As updates are made submitted from the company contracted land base vendor
Foot and Aerial Patrol	Annual
Identified Sites (as defined by RMP-08)	Annual
Parcel Data (as required by RMP-08)	Annual
Identified Sites provided by Public Safety Officials (as required by RMP-06)	Bi-Annual

* Land Base information includes: Airports, Roads, Highways, Railroads, Water Crossings (Other than Navigable Waterways), parks, etc.

8.4 ALGORITHM REVIEW

At least once each calendar year, the Integrity Management Group will review the threat and consequence algorithms with the appropriate steering committees and make changes as necessary to reflect regulatory requirements and best industry practices.

8.5 REVISION TO RISK CALCULATIONS

Risk calculations shall be reviewed annually and recalculated as necessary to reflect changes to facility, threat, or consequence data, and/or changes to the threat or consequence algorithms.

9.0 RISK FOR INTEGRITY MANAGEMENT

9.1 Additional Note on IC and SCC 7

As noted previously, PG&E's HCA risk calculation does not address two of the threats existing in a few of its covered pipelines; Internal Corrosion (IC) and Stress Corrosion Cracking (SCC). The likelihoods of failure for these threats were not included because they are currently relevant to a small portion (approximately 2%) of the HCA pipeline segments. Instead pipelines with these threats were categorized as "high risk" and scheduled for assessment prior to 12/17/2007. The only exceptions are:

- 25.5 miles of Stanpac 3 with IC threat that will be MFL inspected in 2007 and
- 6442' in two DFMs that were installed between 1989 and 1994. One of the DFMs is operating under 20% SMYS and was direct assessed in 2009. The second, operating at 41% SMYS, will be smart-pigged in 2012.

The following assessments shall be performed on an on-going basis to validate the current threat assumptions:

For SCC:

- All direct examinations performed as part of the integrity management program shall determine, using an appropriate inspection tool, if SCC damage is present, whether the pipe segment was identified as possessing the threat or not.

For IC:

- All ILI assessments identify that identify wall loss due to IC shall determine, using appropriate inspection tool, if IC damage is actually present.
- All direct examinations performed as part of the integrity management program shall determine, using appropriate inspection tool, if IC damage is present.

Work is currently underway to add IC, SCC, I/O and Equipment risk into the risk assessment process.

9.2 Historical Calculation of HCA Risk 7

*In the first three years of the program, segments identified as high risk per CFR 49 were scheduled within the first three years of the IM program.

This equation was used to determine the high risk segments:

HCA RISK = LOF*(1+(PIR/1800))

Where, LOF = Likelihood of Failure based on Equation 2 of this procedure.

PIR = Potential Impact Radius as defined by RMP-08

Pacific Gas and Electric

Integrity Management Program Change Form

Changes for RMP- 01
Revision 07 Date 3/26/12

Standard Pacific Pipelines Inc.
Attachment D to RMP-06

Section	Change	Reason for Change	Implication of Change
1.0 Purpose	Added reference to RMP-15.	Provided reference to DIMP program in RMP-15.	Improved continuity between RMP documents.
2.0 Scope	Updated sections 2.1 (General), and added sections 2.2 Transmission and 2.3 Distribution. Updated scope of transmission facilities and included reference to FAQ 84.	Corrected grammar in 2.1 and added sections 2.2 and 2.3 to differentiate requirements between Transmission and Distribution facilities. Change in scope is to align with FAQ 84.	Document more clearly defines how the procedure is implemented between distribution and transmission facilities. Program better aligns with Code interpretations provided by PHMSA.
3.0 Introduction	Removed sections that are duplicated in the Section 1.0 and RMP-06. Corrected a typo in the number of basic pipeline threats (5 to 4). Removed rationale regarding why IC and SCC are not addressed in the document. Added info on current process to add IC, SCC to document. Also added section regarding i/o and equipment having an equivalent risk and work is underway to identify a methodology that's provides a more gradient approach for future risk assessments.	Duplication with other procedures Correction of typo. Algorithm work is currently in development.	More alignment between RMP documents and reduced duplication. Improved accuracy in procedure. Work underway to add IC and SCC into the risk assessment process.
4.0 Roles and Responsibilities	Updated titles. Added responsibility to the Integrity Management Manager to assign committee chairpersons.	Updated document to align with current procedure and RMP-15.	Improved continuity between RMP procedures.
5.0 Training and Qualifications	Added referenced to RMP-15	Better identify requirements related to DIMP.	Improved continuity between RMP procedures.
6.0 Risk Determination	Updated language regarding the selection of the committee chairpersons.	Updated document to align with current procedure and RMP-15.	Continuity with this document and RMP-15.
6.0 Risk Determination	In 6.2.5, changed the review requirements for the LOF and COF committees. Changed the prescriptive requirements of evaluating certain types of segments to a more generic description of "the output of the algorithm" and performance metrics.	The change allows the committees to broaden the items in which they evaluate when validating the algorithm.	Allows for more flexibility in the validation process.
6.0 Risk Determination	In 6.3, changed the weighting factors in Equation 2 for the individual threat categories. TP (from .45 to .41) GM (from .20 to .16) DM (from .10 to .18)	This changed was approved by the Consequence Team and from the TP, GM and DM Committees. This change was based upon INGAA industry reports, internal leakage data, reduced 3rd party damage trends, incident history and recent data gathering efforts.	Update to the algorithm based upon new information.

PG&E

Pacific Gas and Electric

Integrity Management Program Change Form

Changes for RMP- 01
Revision 07 Date 3/26/12

Standard Pacific Pipelines Inc.
Attachment D to RMP-06

Section	Change	Reason for Change	Implication of Change
6.0 Risk Determination	Updated two of the conditions where FSF cannot be taken as less than one. The two conditions were: 1) Changed the install date range from "where pipeline or segments were installed prior to 1947 and are in an area of ground acceleration" to prior to 1962.	The change in the date range was based upon the requirement for weld inspection that began in 1962 per GO 112.	Improved risk criteria.
	2) Changed the install date range from "where pipeline or segments were installed prior to 1947 and are in an area of ground acceleration and unstable soil" to prior to 1962.	The change in the date range was based upon the requirement for weld inspection that began in 1962 per GO 112.	The change in the date range was based upon the requirement for weld inspection that began in 1962 per GO 112.
Section 7.0 Risk Mitigation	Added note that section is applicable only to transmission facilities. Denoted that mitigation of distribution facilities is addressed in RMP-15.	Differentiation between transmission and distribution mitigation efforts.	Improved language.
	Updated mitigation strategy table.	Updated abbreviations from "L" to "LOF" to be consistent with other RMP documents.	Clarity.
Section 7.0 Risk Mitigation	Updated reporting of risk values. Denoted that Risk and IMA Risks are reported in the Integrity Management Plan for covered segments.	Updated procedure based upon current process.	Document describes current process more accurately.
Section 8.0 RMP Maintenance	Added reference to RMP-15.	Updated to include DIMP reference.	Improved continuity between RMP procedures.
	Updated table in section 8.3. Removed duplicate entries (Highway, and Airports) since they are already included in land base changes. Updated interval dates based upon current practice.	Table update intervals were no longer accurate based upon current mapping practices. Removed duplicate entries.	Document describes current process more accurately.
Section 9.0 Risk for Integrity Management	Added section numbers	Better organization	Administrative.
	Updated IC and SCC section to reflect PG&E's intention to add these threats to its risk assessment process.	Identified a future update to the risk methodology	Continuous improvement effort to the program.
	Added clarification regarding how the "HCA Risk" equation was used in the first three years of the program.	This equation is historical in nature and a qualifier was added to address its current applicability.	Clarification of the process.
	IMA COF equation was removed.	The IMA COF equation was removed as an option to calculate the consequence factor. Equation 3 in section 6.4 better aligns with the requirements of ASME B31.8S for the calculation of the consequence for a covered pipeline segment.	Removed alternate COF equation.

PACIFIC GAS AND ELECTRIC COMPANY

GAS ENGINEERING & OPERATIONS
INTEGRITY MANAGEMENT

Risk Management Procedure

Procedure No. RMP-02
Revision 6
External Corrosion Threat Algorithm

Gas Transmission Integrity Management Program
for PG&E and Standard Pacific Pipeline Inc.

Redacted

Prepared By: Date: 12/29/11
Redacted Integrity Management Program Manager

Concur: Date: 3-15-12
Sara Peralta, Manager, Integrity Management

Concur: N/A Date: N/A
Director, Integrity Management

Concur: Date: 3/26/12
Sanford Hartman, Vice President, Managing Director, Law

Approved By: Date: 3/17/2012
Roland Trevino, Vice President, Public Safety & Integrity Mgmt

Rev. No.	Date	Description	Prepared By	Approved By	Approved Manager, System Integrity
0	11/26/01	Initial Issue	Redacted	Redacted	Redacted
1	1/8/03	Revised as Shown			
2	6/13/05	Revised as shown-added section 5.0		RPF2	
3	10/22/05	Revised as shown		Redacted	
4	7/12/06	Revised as shown			
5	1/14/10	Revised as shown			SEBE - Manager RPF2 - Director

Rev No	Date	Description	Prepared by	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
6	3/26/12	Revised as shown.	Redac	SEBE	NA	SLHB	RIT4

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1.0 PURPOSE

The purpose of this procedure is to provide a guideline for determining the External Corrosion Threat Algorithm for the determination of Likelihood of Failure and Risk for PG&E's Risk Management Program (RMP) and Integrity Management Program.

2.0 SCOPE

2.1 Transmission

This guideline is applicable to all of PG&E's gas transmission pipeline facilities and is to be used in conjunction with Risk Management Procedure, RMP -01. The algorithm provided in this procedure is for transmission pipelines and associated appurtenances per Section 2.2 of RMP-01. 6

The Integrity Management Group is responsible for managing risk within the scope of this procedure. The Integrity Management Group shall establish and manage the risk of each pipeline facility by utilizing industry and regulatory accepted methodologies appropriate for PG&E's gas transmission facilities and shall be in conformance with this procedure. The Integrity Management Program Manager shall be responsible for compliance with this procedure in relation to determining the external corrosion likelihood of failure.

2.2 Distribution

Gas Distribution Integrity Management Program (DIMP) risk ranking is intended to meet the requirements of 49 CFR 192 Subpart P. DIMP performs a risk assessment to identify and prioritize risks for distribution pipelines per 4.3 of RMP-15. . The algorithm provided in this procedure is used for distribution pipelines and associated appurtenances operating over 60 psig. 6

3.0 INTRODUCTION

The risk management process is a process of integrating data to calculate risk, developing risk mitigation plans to bring and maintain risk within an acceptable risk profile, and monitoring risk to accommodate changes in the factors which affect risk. The Transmission Integrity Management Program (TIMP) is a program established by PG&E to address the integrity management rules in 49 CFR Part 192 Subpart O. RMP-06 provides procedures for compliance with the Transmission Integrity Management Program (TIMP).

Procedure RMP-15 provides procedures for compliance with the Distribution Integrity Management Program (DIMP).

Procedure RMP-01 provides a procedure for the Risk Management Process. This procedure supports the calculation of risk, required by Procedure RMP-01, RMP-06 and RMP-15 due to External Corrosion (EC), one of the basic threats imposed on gas pipelines. 6

As described in RMP-01, Risk is defined as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). A relative risk calculation methodology is used to establish risk for all pipeline segments within the scope of RMP-01. The method used to calculate risk is based on an index model and qualitative scoring approach. Likelihood Of Failure (LOF) is defined as the sum of the following threat categories: External Corrosion (EC), Third Party (TP), Ground Movement (GM) and Design/Materials (DM).

Each threat category is weighted in proportion to PG&E and industry failure experience. EC is weighted at 25%. The weightings on the threat categories will be reviewed and approved annually by the Consequence Steering Committee. For each threat category, the appropriate steering committee will identify the significant factors that influence the threat's likelihood of failure. For each factor, a percentage weighting will be established to identify the factor's relative significance in determining the threat's likelihood of failure within the threat algorithm. Points will be established based on criteria that the committee feels is significant to determining the threat's likelihood of failure due to each factor and the relative severity of failure (leak-before-break vs. rupture). (Negative points may be assigned where current assessments have been made to confirm pipeline integrity and/or mitigation efforts have eliminated or lowered susceptible to a threat.) Generally, the summation of the percentage weightings for all of the factors within each threat will be 100%. (There may be exceptions to permit the consideration of very unusual conditions.)

For the threat of EC, the scoring is based on direction from the EC Steering Committee. The EC Steering Committee shall meet at least once each calendar year and shall review this procedure per the requirements of RMP-01.

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4.0 Roles and Responsibility

Specific responsibilities for ensuring compliance with this procedure are as follows:

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Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager of Integrity Management	• Supervise completion of work (schedule/quality) • Monitor compliance to procedure – take corrective actions as necessary. • Assign qualified individuals • Ensure Training of assigned individuals • Assign Steering Committee Chairman, and ensure that meetings are held once each calendar year.
Steering Committee Chairman (Risk Management Engineers)	Integrity Management Program Manager (except for TP Steering Committee – chairman reports to Manager System Integrity)	• Arrange meetings. • Review procedure with committee per RMP-01 • Provides meeting minutes • Ensures action items are completed.
Steering Committee Members (Subject Matter Experts)	Various	• Attend meetings as requested by Steering Committee Chairman. • Provide review and direction to procedure.
Risk Management Engineers	Integrity Management Program Manager	• Perform calculations per procedure.

5.0 Training and Qualifications

See RMP-06 and RMP-15 for qualification requirements. Specific training to ensure compliance with this procedure is as follows:

Position	Type of Train ing:	How Often
Integrity Management Program Manager	Procedure review of RMP-01 and RMP-02	• Upon initial assignment • Once each calendar year.
Steering Committee Chairman	Procedure review of RMP-01 and RMP-02	• Upon initial assignment • Once each calendar year. • As changes are made to the procedure.
Steering Committee Members (Subject Matter Experts)	Review RMP-02 and Steering Committee requirements of RMP-01	• Once each calendar year at the time of the steering committee meeting.
Risk Management Engineers	Per RMP-06 and RMP-15 requirements.	• Upon initial assignment • Once each calendar year. • As changes are made to the procedure.

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6.0 EC Threat Algorithm

6.1 Gas Transmission/ Gas Distribution (above 60 psig) 6

Scoring for the External Corrosion (EC) threat algorithm shall be calculated per the direction of the EC Steering Committee. The committee has determined that the factors in A through M of this section are significant for determining the Likelihood of Failure (LOF) of a gas pipeline due to EC. The EC contribution to LOF shall be the summation of assigned points times the assigned weighting of the following factors:

A) Soil Resistivity (4% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
Less than or equal 500 Ohm-Centimeters	100	4
501 to 1000 Ohm-Centimeters	80	3.2
1001 to 2000 Ohm-Centimeters	60	2.4
2001 to 4000 Ohm-Centimeters	40	1.6
4001 to 10,000 Ohm-Centimeters	20	0.8
Above 10,000 Ohm-Centimeters	10	0.4

Default = Above 10,000 Ohm-Centimeters

B) Corrosion Survey Criteria (5% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
No CIS*/ readings	50	2.5
CIS & meets criteria for acceptance	-100	-5
CIS & does not meet acceptance criteria	300	15

* CIS – (Close Interval Survey) This information is provided to the RMP by the Corrosion Engineer and, if acceptable, is considered valid for ten years. If the CIS does not meet acceptance criteria, it is valid until repeated.

C) Coating Visual Inspection[1] (8% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Severely disbonded, (Poor)	100	8
Locally damaged, disbonded (Fair)	50	4
Superficial damage only (Good)	20	1.6
Intact and bonded (Excellent)	10	0.8
Bare Pipe or No Inspection (Coating Age[2] ≤ 5 Years)	11	0.88
Bare Pipe or No Inspection (Coating Age[2] > 5 to ≤ 20 Years)	19	1.52
Bare Pipe or No Inspection (Coating Age[2] > 20 to ≤ 30 Years)	29	2.32
Bare Pipe or No Inspection (Coating Age[2] > 30 Years)	51	4.08

[1] Inspection data greater than 20 years old shall not be used unless the information reflects a condition that is fair or poor. In such cases, points will be awarded per the inspection regardless as to when the inspection was performed.

[2] For Bare Pipe substitute Pipe Age.

D) Casing Survey (3% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
No casing or Gelled	0	0
Existing casing	20	0.6
Metallic shorted casing	100	3

E) In-Line-Inspection (ILI) (5% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
No survey performed	0	0
Inspection > 10 years old	-100	-5
Inspection 5 to 10 years old	-300	-15
Inspection 2 to <5 years old	-600	-30
Inspection <2 years old	-600	-30

F) External Corrosion Leak[1] Rate (14% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Leak in last 5 years	100	14
Leak in last 10 Years	80	11.2
Leak age >10 years	50	7
No reported Leaks	0	0

[1] Points applied to all pipe segments of similar vintage and coating type within a 1 mile radius of a leak.

G) Coating Design (8% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Shielding Coatings	100	8
Non-Shielding Coatings	10	0.8
Bare	30	2.4
Paint	10	0.8
Default (Installation date ≥ 1960 – Assume Tape or equiv.)	100	8
Default (Installation date ≤ 1960 – Assume HAA or equiv.)	10	0.8

H) DC/AC Interference (10% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
High or medium voltage within 500' of a Gas Pipeline without Cathodic Protection	100	10
High or medium voltage w/i 500' w/CP	50	5
No high or medium voltage	0	0

6

I) Coating Age (5% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
>30 years	100	5
>20 to 30 years	80	4
>10 to 20 years or uncoated	30	1.5
10 years or less	10	0.5

J) MOP vs. Pipe Strength* (8% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
>60%	100	8
50% to 60%	80	6.4
40% to <50%	50	4
30% to <40%)	30	2.4
20% to <30%	10	0.8
Less than 20%	5	0.4

* Pipe Strength shall be determined to be equal to (SMYS)(2)(t)(Jef)/(OD).

K) Pipe Visual Inspection[1] (10% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Heavy pitting or gouging (Poor)	100	10
Light pitting or gouging (Fair)	50	5
Heavy rusting	20	2
Light rusting (Good)	10	1
No pitting or rusting (Excellent)	0	0
No Inspection (Pipe Age $\leq$ 5 Years)	0	0
No Inspection (Pipe Age > 5 to $\leq$ 20 Years)	10	1
No Inspection (Pipe Age > 20 to $\leq$ 30 Years)	20	2
No Inspection (Pipe Age > 30 Years)	40	4

[1] Inspection data greater than 20 years old shall not be used unless the information reflects a condition that is fair or poor. In such cases, points will be awarded per the inspection regardless as to when the inspection was performed.

L) Test Pressure (TP)(5% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
No Records Available	0	0
TP age is $\leq$ ASME B31.8S Table 3 requirements for Hydrostatic Test Interval	-200	-10
TP age is $\leq$ 3 years more than ASME B31.8S Table 3 requirements for Hydrostatic Test Interval	-100	-5
TP is > 3 years more than ASME B31.8S Table 3 requirements for Hydrostatic Test Interval	0	0

M) External Corrosion Direct Assessment (ECDA) (Weighting 10%) Points awarded as follows:

Criteria	Points	Contrib.
ECDA Completed*	-200	-20
ECDA Not Completed	0	0

* ECDA must have been completed within the last ten years.

Pacific Gas and Electric

Integrity Management Program Change Form

Changes for RMP- 02
Revision 06 Date 3/26/12

Standard Pacific Pipelines Inc.
Attachment D to RMP-06

Section	Change	Reason for Change	Implication of Change
Cover Sheet	Updated to include revision 6 and include updated list of approvers.	New revision to be published	Administrative.
Section 2.0	Removed not applicable to regulator, compressor or underground storage facilities. Added reference to RMP-01 Section 2.2 Scope Added Section 2.2 for Distribution and denoted applicability to distribution facilities operating above 60 psig.	Updated scope to align with FAQ 84. Update language and references to RMP-15	Added clarity of language and adds cross reference to pertinent RMP-15 sections.
Section 3.0 Introduction	Added RMP-15 reference	Update generated by changes to RMP-15.	Improved continuity between RMP documents.
Section 4.0 Roles and Responsibility	Updated roles	Changes in titles	n/a
Section 5.0 Training and Qualifications	Added reference for RMP-15 and updated training references	Identifies requirements for distribution facilities	Improved continuity between RMP documents.
Section 6.1	Added reference Gas Distribution (above 60 psig) to 6.1 Table 6.1C correction changed value of' Bare Pipe or No Inspection' from 40.8 to 4.08 Table 6.1H changed contribution value from 9 to 10 for high or medium voltage within 500 ft of a gas pipeline without CP and changed contribution value from 4.5 to 5 for high or medium voltage	Adds clarity that procedure is intended for gas distribution facilities operating above 60 psig. Corrected typographical error in the documentation Corrected rounding errors in the documentation	None. Corrected error in documentation. Did not impact algorithm or calculations. Corrected error in documentation. Did not impact algorithm or calculations.
Section 6.2	Removed. No longer using a relative risk model for 60 psig and under distribution facilities.	New version of RMP-15 made existing language in RMP 02 out of date.	Improved continuity between RMP documents.

PACIFIC GAS AND ELECTRIC COMPANY
GAS ENGINEERING & OPERATIONS
INTEGRITY MANAGEMENT

Risk Management Procedure

Procedure No. RMP-03
Revision 6
Third Party Threat Algorithm

Gas Transmission Integrity Management Program
for PG&E and Standard Pacific Pipeline Inc.

Prepared By: Redacted **Date:** 12/29/11
Redacted Integrity Management Program Manager

Concur: Sara B. Peralta **Date:** 3-15-12
Sara Peralta, Manager, Integrity Management

Concur: N/A **Date:** N/A
Director, Integrity Management

Concur: **Date:** 3/20/12
Sanford Hartman, Vice President, Managing Director, Law

Approved By: **Date:** 3/17/2012
Roland Trevino, Vice President, Public Safety & Integrity Mgmt

Rev. No.	Date	Description	Prepared By	Approved By	Approved Manager, System Integrity
0	11/13/01	Initial Issue	Redacted		Redacted
1	3/14/03	Revised as shown		Redacted	
2	6/13/05	Revised as shown			
3	10/28/05	Revised as shown			
4	12/27/08	Reviewed and added DIMP			Director System Integrity & Gas Issues Bob Fassett
5	12/28/09	Revised as shown			SEBE-Manager RPF2 - Director

Rev No	Date	Description	Prepared by	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
6	3/26/12	Revised Weighting in Risk Calculation	Reda	SEBE	N/A	SLHB	RIT4

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RISK MANAGEMENT PROCEDURE

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1.0 PURPOSE

The purpose of this procedure is to provide a guideline for determining the Third Party (TP) Threat Algorithm for the determination of Likelihood of Failure and Risk for PG&E's Risk Management Program (RMP) and Integrity Management Program.

2.0 SCOPE

2.1 Transmission

This guideline is applicable to all of PG&E's gas transmission pipeline facilities and is to be used in conjunction with Risk Management Procedure, RMP- 01. The algorithm provided in this procedure is for transmission pipelines and associated appurtenances per 2.2 of RMP-01. 6

The Integrity Management Group is responsible for managing risk within the scope of this procedure. The Integrity Management Group shall establish and manage the risk of each pipeline facility by utilizing industry and regulatory accepted methodologies appropriate for PG&E's facilities and shall be in conformance with this procedure. The Integrity Management Program Manager shall be responsible for compliance with this procedure.

2.2 Distribution

Gas Distribution Integrity Management Program (DIMP) risk assessment is intended to meet the requirements of 49 CFR 192 Subpart P. DIMP performs a risk assessment to identify and prioritize risks for distribution pipelines per Section 4.3 of RMP-15. The algorithm provided in this procedure is for distribution pipelines and associated appurtenances operating over 60 psig. 6

3.0 INTRODUCTION

The risk management process is a process of integrating data to calculate risk, developing risk mitigation plans to bring and maintain risk within an acceptable risk profile, and monitoring risk to accommodate changes in the factors which affect risk. The Transmission Integrity Management Program (TIMP) is a program established by PG&E to address the integrity management rules in 49 CFR Part 192 Subpart O. RMP-06 provides procedures for compliance with the Transmission Integrity Management Program (TIMP). 6

Procedure RMP-15 provides procedures for compliance with the Distribution Integrity Management Program (DIMP).

Procedure RMP-01 provides a procedure for the Risk Management Process. This procedure supports the calculation of risk, required by RMP-01, RMP-06 and RMP-15 due to third party damage (TP), which is one of the basic threats to gas pipelines.

As described in RMP-01, Risk is defined as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). A relative risk calculation methodology is used to establish risk for all pipeline segments within the scope of RMP-01. The method used to calculate risk is based on an index model and qualitative scoring approach. Likelihood of Failure (LOF) is defined as the sum of the following threat categories: External Corrosion (EC), Third Party (TP), Ground Movement (GM) and Design/Materials (DM).

Each threat category is weighted in proportion to PG&E and industry failure experience. TP is weighted at 41%. The weightings on the threat categories will be reviewed and approved annually by the Consequence Steering Committee. For each threat category, the appropriate steering committee will identify the significant factors that influence the threat's likelihood of failure. For each factor, a percentage weighting will be established to identify the factor's relative significance in determining the threat's likelihood of failure within the threat algorithm. Points will be established based on criteria that the committee feels is significant to determining the threat's likelihood of failure due to each factor and the relative severity of failure (leak-before-break vs. rupture). (Negative points may be assigned where current assessments have been made to confirm pipeline integrity and/or mitigation efforts have eliminated or lowered susceptible to a threat.) Generally, the summation of the percentage weightings for all of the factors within each threat will be 100%. (There may be exceptions to permit the consideration of very unusual conditions.) 6

For the threat of TP, the scoring is based on direction from the Third Party Damage Committee.
The Third Party Damage Committee shall meet at least once each calendar year and shall review this procedure per the requirements of RMP-01.

4.0 Roles and Responsibility

Specific responsibilities for ensuring compliance with this procedure are as follows:

6

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager of Integrity Management	• Supervise completion of work (schedule/quality) • Monitor compliance to procedure – take corrective actions as necessary. • Assign qualified individuals • Ensure Training of assigned individuals • Assign Steering Committee Chairman, and ensure that meetings are held once each calendar year.
Steering Committee Chairman (Risk Management Engineers)	Appointed by Integrity Management Program Manager. Who the chairmen reports to will vary.	• Arrange meetings. • Review procedure with committee per RMP-01 • Provides meeting minutes • Ensures action items are completed.
Steering Committee Members (Subject Matter Experts)	Various	• Attend meetings as requested by Steering Committee Chairman. • Provide review and direction to procedure.
Risk Management Engineers	Integrity Management Program Manager	• Perform calculations per procedure.

5.0 Training and Qualifications

See RMP-06 and RMP-15 for qualification requirements. Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training:	How Often
Integrity Management Program Manager	Procedure review of RMP-01, RMP-03	• Upon initial assignment • Once each calendar year.
Steering Committee Chairman	Procedure review of RMP-01 and RMP-03	• Upon initial assignment • Once each calendar year or as changes are made to the procedure.
Steering Committee Members (Subject Matter Experts)	RMP-03 and Steering Committee requirements of RMP-01	• Once each calendar year at the time of the steering committee meeting.
Risk Management Engineers	Per RMP-06 and RMP-15 requirements	• Once each calendar year or as changes are made to the procedure.

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6.0 Third Party Threat Algorithm

6.1 Gas Transmission/ Gas Distribution (above 60 psig):

6

Third Party (TP) threats shall be calculated per the direction of the Third Party Damage Committee. The committee determined that the factors in A through J of this section are significant for determining the Likelihood of Failure (LOF) of a transmission gas pipeline due to *third party* damage. The TP contribution to LOF shall be the summation of assigned points times the assigned weighting of the following factors:

A) Potential Ground Breaking Frequency (13% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
Dig-in Concern*	100	13
Class 3 and 4 Areas	100	13
Class 2 Area	50	6.5
Class 1 Area	10	1.3

* Dig-In concerns will be reported to the RMP by District/Division personnel every two years. They shall also be within a ½ mile of a leak that has occurred within the last 10 years, unless some mitigation efforts have been documented. (See RMI 02)

6

B) Third Party Damage Prevention (10% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
None	0	0
Standby	-100	-10
Aerial Patrol	-20	-2

C) Ground Cover Protection (15% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
More than 5.99'	10	1.5
> 2.99' to 5.99'	40	6
> 2' to 2.99'	80	12
> 0' to 2'	100	15
0'	60	9
Unknown*	40	6

* DEFAULT.

D) Pipe Diameter (7% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Pipe Diameter <12"	100	7
Pipe Diameter ≥ 12"	0	0

E) Wall Thickness (13% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Less than 0.250 inches	100	13
0.250 to 0.500 inches	30	3.9
Greater than 0.500 inches	10	1.3

F) Line Marking (5% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Line of Sight	10	0.5
Poor Condition	60	3.0
None*	100	5

*Default

G) MOP vs. Pipe Strength* (10% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
>60% (Default)	100	10
50% to 60%	80	8
40% to <50%	50	5
30% to <40%)	30	3
20% to <30%	10	1
Less than 20%	5	0.5

* Pipe Strength shall be determined to be equal to (SMYS)(2)(t)(Jef)/(OD).

H) Third Party Leak* Rate (18% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Pipe Segments with more than one leak** within the impact zone of that segment	150	27
Pipe Segment with one leak within its impact zone	100	18
Pipe Segment in proximity (Leak within the route impact zone and within one mile)	50	9
No Leak	0	0

* Includes both leaks and hits within the last twenty years.

** Only leaks or hits on the same route and within the impact zone are awarded points. Intentionally exceeds 100% weighting.

I) Public Education Program (9% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Field Contact*	-100	-9
Landowner Notification**	-70	-6.3
Trade Show***	-25	-2.25
Public Education not done	0	0

* Field Contact is defined as direct contact at the job site within the last 12 months.

** Points for Landowner Notification will be awarded if a letter was sent to the landowner within the last 24 months.

*** Points are awarded to pipe segments within a 30 mile radius of a trade show when a trade show has been performed within the last 12 months. The Public Awareness Program Manager will keep a record of the trade shows and will establish the area credited for the trade show.

Pacific Gas and Electric

Integrity Management Program Change Form

Changes for RMP- 03
Revision 06 Date 3/26/12

Standard Pacific Pipelines Inc.
Attachment D to RMP-06

Section	Change	Reason for Change	Implication of Change
Cover Sheet	Updated to include revision 6 and include updated list of approvers.	New revision to be published	Administrative.
Section 2.0	Removed not applicable to regulator, compressor or underground storage facilities. Added reference to Section 2.2 of RMP 01. Added Section 2.2 for Distribution and denoted applicability to distribution facilities operating above 60 psig.	Updated scope to align with FAQ 84. Update language and references to RMP-15	Clarity of language and adds cross reference to pertinent RMP-15 sections.
Section 3.0 Introduction	Added RMP-15 reference Changed weighting of Ground Movement Threat in Risk Calculation from 20% to 16%	Update due to changes to RMP-15. New weighting is more accurate with Company Incident History and Industry Data	Continuity between RMP documents. Risk Value Calculation will incorporate this change.
Section 4.0 Roles and Responsibility	Updated roles	Changes in titles	n/a
Section 5.0 Training and Qualifications	Added reference for RMP-15 and updated training references	Identifies requirements for distribution facilities	Continuity between RMP documents.
Section 6.1	Added reference Gas Distribution (above 60 psig) to 6.1 Added RMI-02 reference to 6.1.	Adds clarity that procedure is intended for gas distribution facilities operating above 60 psig. Identified process in which dig-in concerns are collected.	None. Added clarifying language.
Section 6.2	Removed. No longer using a relative risk model for 60 psig and under distribution facilities.	Updated to reflect new Distribution Probabilistic Model. Added language to refer to RMP-15.	None.

PACIFIC GAS AND ELECTRIC COMPANY

GAS ENGINEERING & OPERATIONS
INTEGRITY MANAGEMENT

PG&E

Risk Management Procedure

Procedure No. RMP-04
Revision 06
Ground Movement and Natural Forces Threat Algorithm

Gas Transmission Integrity Management Program
for PG&E and Standard Pacific Pipeline Inc.

Prepared By: Redacted Date: 12/29/11
Redacted , Integrity Management Program Manager

Concur: Sara B Peralta Date: 3-20-12
Sara Peralta, Manager, Integrity Management

Concur: N/A Date: N/A
Director, Integrity Management

Concur: Date: 3/26/12
Sanford Hartman, Vice President, Managing Director, Law

Approved By: Roland Trevino Date: 3/17/2012
Roland Trevino, Vice President, Public Safety & Integrity Mgmt

					Approved
Rev. No.	Date	Description	Prepared By	Approved By	Director of Integrity Management and Technical Support
0	11/24/01	Initial Issue	Redacted	Redacted	Redacted
1	6/11/04	Revised as Shown			
2	10/28/05	Revised as Shown			
3	3/5/07	Revised as Shown			
4	12/27/08	Added Section 6.2-Distribution Algorithm & other minor changes			RPF2
5	10/09/09	Revised as Shown			SEBe/RPF2

Rev No	Date	Description	Prepared by	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
6	3/26/12	Revised weighting in Risk Calculation	Reda	SEBE	N/A	SLHB	RIT4

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1.0 PURPOSE

The purpose of this procedure is to provide a guideline for determining the Ground Movement and Natural Forces Threats Algorithm for the determination of Likelihood of Failure and Risk for PG&E's Gas Transmission and Distribution's Risk Management Programs (RMP) and Integrity Management Programs.

2.0 SCOPE

2.1 Transmission

This guideline is applicable to all of PG&E's gas transmission pipeline facilities and is to be used in conjunction with Risk Management Procedure, RMP- 01. The algorithm provided in this procedure is for transmission pipelines per Section 2.2. of RMP-01. 6

The Integrity Management Group is responsible for managing risk within the scope of this procedure. The Integrity Management Group shall establish and manage the risk of each pipeline facility by utilizing industry and regulatory accepted methodologies appropriate for PG&E's transmission and distribution facilities and shall be in conformance with this procedure. The Integrity Management Program Manager shall be responsible for compliance with this procedure.

2.2 Distribution

6

Gas Distribution Integrity Management Program (DIMP) risk assessment is intended to meet the requirements of 49 CFR 192 Subpart P. DIMP performs a risk assessment to identify and prioritize risks for distribution pipelines per Section 4.3 of RMP-15. The algorithm provided in this procedure is for distribution pipelines operating above 60 psig.

3.0 INTRODUCTION

The risk management process is a process of integrating data to calculate risk, developing risk mitigation plans to bring and maintain risk within an acceptable risk profile, and monitoring risk to accommodate changes in the factors which affect risk. 6 The Transmission Integrity Management Program (TIMP) is a program established by PG&E to address the integrity management rules in 49 CFR Part 192 Subpart O. RMP-06 provides procedures for compliance with the Transmission Integrity Management Program.

Procedure RMP-15 provides procedures for compliance with the Distribution Integrity Management Program (DIMP).

Procedure RMP-01 provides a procedure for the Risk Management Process. This procedure supports the calculation of risk, required by Procedure RMP-01, RMP-06 for transmission pipelines and associated appurtenances and RMP-15 due to Ground Movement (GM), which is one of the basic threats to gas pipelines.

As described in RMP-01, Risk is defined as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). [Risk = LOF X COF] A relative risk calculation methodology is used to establish risk for all pipeline segments within the scope of RMP-01. The method used to calculate risk is based on an index model and qualitative scoring approach. Likelihood of Failure (LOF) is defined as the sum of the following threat categories: External Corrosion (EC), Third Party (TP), Ground Movement (GM) and Design/Materials (DM).

Each threat category is weighted in proportion to PG&E and industry failure experience. GM is weighted at 16%. The weightings on the threat categories will be reviewed and approved annually by the Consequence Steering Committee. For each threat category, the appropriate steering committee will identify the significant factors that influence the threat's likelihood of failure. For each factor, a percentage weighting will be established to identify the factor's relative significance in determining the threat's likelihood of failure within the threat algorithm. Points will be established based on criteria that the committee feels is significant to determining the threat's likelihood of failure due to each factor and the relative severity of failure (leak-before-break vs. rupture). (Negative points may be assigned where current assessments have been made to confirm pipeline integrity and/or mitigation efforts have eliminated or lowered susceptible to a threat.) Generally, the summation of the percentage weightings for all of the factors within each threat will be 100%. (There may be exceptions to permit the consideration of very unusual conditions.) 6

For the threat of GM, the scoring is based on direction from the GM Steering Committee. The GM Steering Committee shall meet at least once each calendar year and shall review this procedure per the requirements of RMP-01.

4.0 Roles and Responsibility

Specific responsibilities for ensuring compliance with this procedure are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager of Integrity Management	• Supervise completion of work (schedule/quality) • Monitor compliance to procedure – take corrective actions as necessary. • Assign qualified individuals • Ensure Training of assigned individuals • Assign Steering Committee Chairman, and ensure that meetings are held once each calendar year.
Steering Committee Chairman (Risk Management Engineers)	Integrity Management Program Manager	• Arrange meetings. • Review procedure with committee per RMP-01 • Provides meeting minutes • Ensures action items are completed.
Steering Committee Members (Subject Matter Experts)	Various	• Attend meetings as requested by Steering Committee Chairman. • Provide review and direction to procedure.
Risk Management Engineers	Integrity Management Program Manager	• Perform calculations per procedure.

5.0 Training and Qualifications

See RMP-06 and RMP-15 for qualification requirements. Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training:	How Often
Integrity Management Program Manager	Procedure review of RMP-01, RMP-04	• Upon initial assignment • Once each calendar year.
Steering Committee Chairman	Procedure review of RMP-01, RMP-04	• Upon initial assignment • Once each calendar year. • As changes are made to the procedure.
Steering Committee Members (Subject Matter Experts)	RMP-04 and Steering Committee requirements of RMP-01	• Once each calendar year at the time of the steering committee meeting.
Risk Management Engineers	Per RMP-06 and RMP-15 requirements.	• Upon initial assignment • Once each calendar year. • As changes are made to the procedure.

6

6.0 GROUND MOVEMENT THREAT ALGORITHM

6.1 Gas Transmission/ Gas Distribution (above 60 psig):

6

Ground Movement (GM) algorithm shall be calculated per the direction of the GM Steering Committee. The committee has determined that the factors in A through H of this section are significant to estimate the Likelihood of Failure (LOF) of a gas pipeline due to *ground movement* damage. The GM contribution to LOF shall be the summation of assigned points times the assigned weighting for the following factors:

A) Crossings* (30% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
Major Water Crossing Present**	40	12
Seismic Fault Crossing Present ***	A	B
No Major Water or Fault Not Present	0	0

* Points for each factor are additive.

** A Major Water Crossing is defined as waterway identified by the Office of Pipeline Safety (OPS) as being a Commercially Navigable Waterway".

*** Seismic Fault Crossings as defined in Attachment 1. A=300*PR (Prob. of Rupture in Attachment 1, the number, 300, is a non-dimensional multiplier used to appropriately weight fault crossings as agreed by the GM Committee), for example: Hayward Fault, PR = 31%, A= (300*0.31) = 93 and B=(0.3*A)=27.9.

B) Unstable Soil (Susceptibility to either slope instability or liquefaction) (15% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
Known Soil Instability or Landslide	120	18
Moderate-High Slope Instability	100	15
Liquefaction*	100	15
None	0	0

* Liquefaction shall be considered for areas defined as Moderate-High or Known Liquefaction within GIS and pipelines installed prior to 1947.

C) Seismic Area* (15% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Seismic Ground Acceleration** ≥ 0.5g	150	22.5
Seismic Ground Acceleration ≥ 0.2g to 0.49g	100	15
Seismic Ground Acceleration < 0.2g	0	0

* Seismic Area shall be considered only if it is in an area of unstable soil. For the purpose of this factor, unstable soil shall be defined as an area of Moderate-High Soil Instability within GIS or areas of Moderate-High or Known Liquefaction within GIS.

** Seismic Ground Acceleration is the peak ground acceleration values to 10% probability of exceedance in 50 years (or 475-year return period).

D) Erosion Area* (10% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Pipe segment within 100 meters of identified erosion area	100	10
Not in erosion area	0	0

* Erosion Area's are reported by the Gas Transmission Erosion Project Manager and also include levee crossings per Pipeline Levee Crossings in the Delta list from the enterprise risk management (ERM) study (Attachment 2) that are susceptible to failure are recorded into GIS on an ongoing basis.

E) Ground Movement Mitigation (5% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Full Ground Movement mitigation* of Known Landslide performed	-360	-18
Partial Ground Movement Mitigation** of Known Landslide performed	-240	-12
Full Ground Movement mitigation* of Known Erosion performed	-200	-10
Partial Ground Movement Mitigation** of Known Erosion performed	-140	-7
Fault Crossing Mitigation***	-6*A	-B
None	0	0

* "Full Ground Movement Mitigation" efforts are projects whose scope substantially removed the ground movement threat of

pipeline failure. This information is reported to the RMP on a case-by-case basis by the appropriate Pipeline Engineer and is documented in the RMP files.

** "Partial Ground Movement Mitigation" efforts are projects whose scope removed some, but not all of the ground movement issues related to a threat to the pipeline. This information is reported to the RMP on a case-by-case basis by the appropriate Pipeline Engineer and is documented in the RMP files.

*** "Fault Crossing Mitigation" is pipeline fault crossing segment that has been evaluated/mitigated per seismic fitness-for-service(F-F-S) (see Attachment 1) and the "Crossing Points" awarded will be removed.

F) Girth Weld Condition (20% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Pre 1947 Girth Welds within area of ground acceleration $\geq$ 0.5g	120	24
Pre 1947 Girth Welds within area of ground acceleration $\geq$ 0.2g to < 0.5g	80	16
All Other	0	0

Pacific Gas and Electric

Integrity Management Program Change Form

Changes for RMP- 04
Revision 06 Date 3/26/12

Standard Pacific Pipelines Inc.
Attachment D to RMP-06

Section	Change	Reason for Change	Implication of Change
Cover Sheet	Updated to include revision 6 and include updated list of approvers.	New revision to be published.	Administrative.
Section 2.0	Removed not applicable to regulator, compressor or underground storage facilities. Added reference to Section 2.2. of RMP-01. Added Section 2.2 for Distribution and denoted applicability to distribution facilities operating above 60 psig.	Updated scope to align with FAQ 84. Update language and references to RMP-15	Clarity of language and adds cross reference to pertinent RMP-15 sections.
Section 3.0 Introduction	Added RMP-15 reference. Changed weighting of Ground Movement Threat in Risk Calculation from 20% to 16%	Update due coincide with changes to RMP-15. Changes based upon INGAA industry reports, internal leakage data, reduced 3rd party damage trends, incident history and recent data gathering efforts.	Continuity between RMP documents. Risk Value Calculation will incorporate this change.
Section 5.0 Training and Qualifications	Added reference for RMP-15	Identifies requirements for distribution facilities	Continuity between RMP documents.
Section 6.1	Added reference Gas Distribution (above 60 psig) to 6.1	Adds clarity that procedure is intended for gas distribution facilities operating above 60 psig.	None.
Section 6.2	Removed	Duplication with RMP-15 and Sections 2.0 and 3.0	None.

PACIFIC GAS AND ELECTRIC COMPANY

GAS ENGINEERING & OPERATIONS
INTEGRITY MANAGEMENT

Risk Management Procedure

Procedure No. RMP-05
Revision 6
Design/Materials Threat Algorithm

Gas Transmission Integrity Management Program
for PG&E and Standard Pacific Pipeline Inc.

Prepared By: Redacted Date: 12/29/11
Redacted Integrity Management Program Manager

Concur: Sara B. Peralta Date: 3-20-12
Sara Peralta, Manager, Integrity Management

Concur: N/A Date: N/A
Director, Integrity Management

Concur: Date: 3/26/12
Sanford Hartman, Vice President, Managing Director, Law

Approved By: Roland Trevino Date: 3/17/2012
Roland Trevino, Vice President, Public Safety & Integrity Mgmt

Rev. No.	Date	Description	Prepared By	Approved By	Approved Mgr/.Dir, Gas Integrity
0	11/13/01	Initial Issue	Redacted	Redacted	SEE ABOVE
1	11/25/03	Revised as Shown			Redacted
2	9/28/05	Revised as Shown			
3	10/28/05	Revised as Shown			
4	12/28/09	Revised as Shown		SEBE	RPF
5	12/28/10	Revised as Shown		Redact	SEBE

Rev No	Date	Description	Prepared by	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Pubic Safety & Integrity Management
6	3/26/12	Revised Weighting in Risk Calculation	Redact	SEBE	NA	SLHB	RIT4

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6.0 DESIGN/ MATERIALS THREAT ALGORITHM 7

1.0 PURPOSE

The purpose of this procedure is to provide a guideline for determining the Design/ Materials (DM) Threat Algorithm for the determination of Likelihood of Failure and Risk PG&E's Risk Management Program (RMP) and Integrity Management Program

2.0 SCOPE

2.1 Transmission

This guideline is applicable to all of PG&E's gas transmission pipeline facilities and is to be used in conjunction with Risk Management Procedure, RMP- 01. The algorithm provided in this procedure is for transmission pipelines and associated appurtenance per Section 2.2 of RMP-01.

The Integrity Management Group is responsible for managing risk within the scope of this procedure. The Integrity Management Group shall establish and manage the risk of each pipeline facility by utilizing industry and regulatory accepted methodologies appropriate for PG&E's CGT facilities and shall be in conformance with this procedure. The Integrity Management Program Manager shall be responsible for compliance with this procedure.

2.2 Distribution

Gas Distribution Integrity Management Program (DIMP) risk assessment is intended to meet the requirements of 49 CFR 192 Subpart P. DIMP performs a risk assessment to identify and prioritize risks for distribution pipelines per Section 4.3 of RMP-15. The algorithm provided in this procedure is for distribution pipelines and appurtenances operating over 60 psig.

3.0 INTRODUCTION

The risk management process is a process of integrating data to calculate risk, developing risk mitigation plans to bring and maintain risk within an acceptable risk profile, and monitoring risk to accommodate changes in the factors which affect risk. The Transmission Integrity Management Program (TIMP) is a program established by PG&E to address the integrity management rules in 49 CFR Part 192 Subpart O. Procedure RMP-06 provides procedures for compliance with the Transmission Integrity Management Program (TIMP).

Procedure RMP-15 provides procedures for compliance with the Distribution Integrity Management Program (DIMP).

Procedure RMP-01 provides a procedure for the Risk Management Process. This procedure supports the calculation of risk, required by Procedure RMP-01, RMP-06 and

RMP-15 due to Design/ Materials (DM) , which is one of the basic threats to gas pipelines. .

As described in RMP-01, Risk is defined as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). A relative risk calculation methodology is used to establish risk for all pipeline segments within the scope of RMP-01. The method used to calculate risk is based on an index model and qualitative scoring approach. Likelihood Of Failure (LOF) is defined as the sum of the following threat categories: External Corrosion (EC), Third Party (TP), Ground Movement (GM) and Design/Materials (DM).

Each threat category is weighted in proportion to PG&E and industry failure experience. DM is weighted at 18%. The weightings on the threat categories will be reviewed and approved annually by the Consequence Steering Committee. For each threat category, the appropriate steering committee will identify the significant factors that influence the threat's likelihood of failure. For each factor, a percentage weighting will be established to identify the factor's relative significance in determining the threat's likelihood of failure within the threat algorithm. Points will be established based on criteria that the committee feels is significant to determining the threat's likelihood of failure due to each factor and the relative severity of failure (leak-before-break vs. rupture). (Negative points may be assigned where current assessments have been made to confirm pipeline integrity and/or mitigation efforts have eliminated or lowered susceptible to a threat.) Generally, the summation of the percentage weightings for all of the factors within each threat will be 100%. (There may be exceptions to permit the consideration of very unusual conditions.) 6

For the threat of DM, the scoring is based on direction from the DM Steering Committee. The DM Steering Committee shall meet at least once each calendar year and shall review this procedure per the requirements of RMP-01.

4.0 Roles and Responsibility

Specific responsibilities for ensuring compliance with this procedure are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager of Integrity Management	• Supervise completion of work (schedule/quality) • Monitor compliance to procedure – take corrective actions as necessary. • Assign qualified individuals • Ensure Training of assigned individuals • Assign Steering Committee Chairman, and ensure that meetings are held once each calendar year.
Steering Committee Chairman (Risk Management Engineers)	Integrity Management Program Manager	• Arrange meetings. • Review procedure with committee per RMP-01 • Provides meeting minutes • Ensures action items are completed.
Steering Committee Members (Subject Matter Experts)	Various	• Attend meetings as requested by Steering Committee Chairman. • Provide review and direction to procedure.
Risk Management Engineers	Integrity Management Program Manager	• Perform calculations per procedure.

6

5.0 Training and Qualifications

See RMP-06 and RMP-15 for qualification requirements. Specific training to ensure compliance with this procedure is as follows: 6

Position	Type of Training:	How Often
Integrity Management Program Manager	Procedure review of RMP-01 and RMP-05	• Upon initial assignment • Once each calendar year.
Steering Committee Chairman	Procedure review of RMP-01 and RMP-05	• Upon initial assignment • Once each calendar year. • As changes are made to the procedure.
Steering Committee Members (Subject Matter Experts)	RMP-05 and Steering Committee requirements of RMP-01	• Once each calendar year at the time of the steering committee meeting.
Risk Management Engineers	Per RMP-06 and RMP-15 requirements	• Upon initial assignment • Once each calendar year. • As changes are made to the procedure.

6.0 DESIGN/ MATERIALS THREAT ALGORITHM

6.1 Gas Transmission/ Gas Distribution (above 60 psig) 6

Design Materials (DM) shall be calculated per the direction of the DM Steering Committee. The committee has determined that the factors in A through G of this section are significant to determining the Likelihood of Failure (LOF) of a gas pipeline due to *design/material* issues. The DM contribution to LOF shall be the summation of assigned points times the assigned weighting for the following factors:

A) Pipe Seam Design (30% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
Furnace Butt Weld (FBW) (Jef = 0.6)	100	30
Single Submerged Arc Weld SSAW (Jef = 0.8)	60	18
Low Freq. ERW* (Jef = 1.0)	90	27
A.O.Smith or Flash Weld (Jef =0.8)	90	27
Lap Weld (Jef=0.8)	90	27
High Freq. ERW (Jef = 1.0)	20	6
1962 and newer Double Submerged Arc Weld (DSAW) (Jef = 1.0)	10	3
Pre1962 Double Submerged Arc Weld (DSAW) (Jef-1.0)	20	6
Seamless	10	3
Pre 1990 Spiral (Jef = 0.8)	90	27
1990 and newer Spiral (Jef=1.)	20	6
Other	100	30
Default (Welds made prior to 1970)	100	30
Default (Welds made in 1970 and after)	20	6

* Welds made prior to 1970 using the ERW welding process are assumed to be made using low frequency unless otherwise noted

B) Girth Weld Condition (15% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
Pre 1930 Girth Welds (Both Arc and oxyacetylene, regardless of seismic zone)	100	15
Pre 1947 Girth Welds within area of ground acceleration $\geq$ 0.2g	100	15
Shielded pre-1960 Bell-Spigot/BBCR**	40	6
Default	0	0

** Shielded Metal Arc Welds (SMAW) made prior to 1960 or girth weld joints made with Bell-Spigot or BBCR joints.

C) Material Flaws or Unique Joints (20% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Wrinkle Bends in Pipe w/ OD $\leq$ 12"	100	20
Wrinkle Bends in Pipe w/ OD > 12"	50	10
Dresser Couplings or Expansion Joints	100	20
Hard Spots *	100	20
Pre 1962 Miter Bends	90	18
None	0	0

* Hard Spots point shall be awarded based on mill and age regardless of whether hard spots have been found

D) Pipe Age (10% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Pre 1970 Pipe	100	10
1970 and newer pipe	10	1

E) MOP vs. Pipe Strength* (20% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
>60%	100	20
50% to 60%	80	16
40% to <50%	50	10
30% to <40%)	30	6
20% to <30%	10	2
Less than 20%	5	1

* Pipe Strength shall be determined to be equal to (SMYS)(2)(t)(Jef)/(OD).

F) Design/Materials Leak Rate (5% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
More than 1 leak	200	10
1 leak	160	8
0 leak	0	0

1 Any leak on a pipe segment shall be awarded 160 points. In addition any pipe on the same installation job number with similar pipe properties shall also be awarded 160 points. 6

2 If more than 1 leak occurs on the same job number with similar segments, all pipes shall be assigned 200 points.

3 If a leak occurs on a segment with no job number, all similar pipe within 20 miles shall be assigned the point weightings as well.

G) Test Pressure (TP)** vs. Pipe Strength* (20% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
TP ≥ 90%PS (test is 5 years old or less)	-200	-40
TP ≥ 90%PS (test is more than 5 years old)	-150	-30
TP≥ 80% TO 90%	-100	-20
TP < 80% PS	-50	-10
No Pressure Test or TP/MOP <1.1	150	30

* Pipe Strength (PS) shall be determined to be equal to (SMYS)(2)(t)(Jef)/(OD).

** Pressure Tests performed earlier than 1950 will not be credited.

PG&E
Pacific Gas and Electric

Integrity Management Program Change Form

Changes for RMP- 05
Revision 6 **Date 3/26/12**

Standard Pacific Pipelines Inc.
Attachment D to RMP-06

Section	Change	Reason for Change	Implication of Change
Cover Sheet	Updated to include revision 6 and include updated list of approvers.	New revision to be published	Administrative
2.0 Scoe	Removed not applicable to regulator, compressor or underground storage facilities. Added reference to Section 2.2. of RMP-01. Added Section 2.2 for Distribution and denoted applicability to distribution facilities operating above 60 psig.	Updated scope to align with FAQ 84. Updated scope based upon changes to RMP-15.	Clarity of language and adds cross reference to pertinent RMP-15 sections.
3.0 Introduction	Provided clarity language for the differing requirements of TIMP and DIMP programs that use RMP-05 for the calculation of DM risk.	Better distinction between programs	Additional clarity
3.0 Introduction	Increase DM LOF weighting to 18%.	Revise algorithm per approved changes of the Consequence Steering Committee INGAA industry reports, internal leakage data, reduced 3rd party damage trends, incident history and recent data gathering efforts.	Risk ranking will change due to the design material weighting changes.
3.0 Introduction	Delete paragraph that references the DM threat to Section 7.0 of RMP-05	Section 7.0 of RMP-15 is deleted in this version	Refer to RMP-15 for DM risk threat
4.0 Roles and Responsibility	Updated titles and references to RMP-06 and RMP-15.	Changes in organizational structure	Better clarity in roles and responsibilities
6.1A	Add 1962 or newer for the current DSAW	DSAW was made in 1962 or later has volumetric NDE per API-5L requirement therefore it is considered better steel quality.	Risk ranking change for DSAW pipe that made before 1962
6.1A	New weighting for Pre 1962 DSAW	DSAW was made in 1962 or later has volumetric NDE per API-5L requirement therefore it is considered better steel quality	Risk ranking change for DSAW pipe that made before 1962
6.1A	Add footnote to clarify ERW made prior to 1970 is assumed low frequency	Clarify for pre 1970 ERW without record	Clarification only
6.1.F	Updated 6.1F to clarify how risk points are assigned to segments	Procedural step did not address all situations.	Added clarity
6.2 Gas Distribution	Removed. References to RMP-15 are provided in the introduction and scope sections.	Duplication with RMP-15 and Sections 2.0 and 3.0	None.

PACIFIC GAS AND ELECTRIC COMPANY

GAS OPERATIONS

PUBLIC SAFETY & INTEGRITY MANAGEMENT

PG&E

Risk Management Procedure

Procedure No. RMP-01
Revision 8
Risk Management

Gas Transmission Integrity Management Program
for PG&E and Standard Pacific Gas Line, Inc.

Prepared By: Redacted Date: 7/10/12
Redacted Risk Management Supervisor

Concur: Redacted Date: 7/25/12
Redacted, Integrity Management Engineering Manager

Concur: Date: 7-16-12
Bennie Barnes, Director, Transmission Integrity Management

Concur: Date: 7-27-12
Sanford Hartman, Vice President, Managing Director, Law

Approved By: Date: 7/29/2012
Roland Trevino, Vice President, Public Safety & Integrity Management

Rev. No.	Date	Description		Prepared By	Approved By	Approved Manager, System Integrity	
0	11/13/01	Initial Issue		Redacted	Redacted	Redacted	
1	1/8/03	Revised as shown					
2	6/29/04	Revised as shown					
3	11/16/04	Revised as shown					
4	6/9/05	Revised as shown					
5	10/31/05	Revised as shown					
6	1/10/11	See Change Form				SEBE	
Rev No	Date	Description	Prepared by	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
7	3/26/12	See Change Form	Redact	SEBE	NA	SLHB	RIT4
Rev No	Date	Description	Prepared by	Manager, Integrity Management Engineering	Director, Transmission Integrity Management	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
8	7/29/12	See Change Form	Redacte	Redact	B2BY	SLHB	RIT4

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1.0 PURPOSE

The purpose of this procedure is to describe the process for maintaining the Risk Management Program (RMP) and complying with the requirements for risk calculations as part of PG&E's Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP), which are described in RMP-06 and RMP-15, respectively.

2.0 SCOPE

2.1 General

The Risk Management Group is responsible for managing risk within the scope of this procedure. The Risk Management Group shall establish the risk of each pipeline facility using methodologies that are:

- consistent with industry practice
- acceptable to regulatory agencies
- appropriate to PG&E's gas facilities
- in conformance with this procedure

The Risk Management Group shall apply this procedure, and as appropriate, partner with Pipeline Engineering, the System Integrity Group and other internal organizations to apply this procedure in an effort to manage risk.

In accordance with IMP procedures, risk information shall be communicated to management and other appropriate PG&E personnel for project planning, risk mitigation, inspection planning, and regulatory reporting. Per RMP-06, risk for each pipeline segment shall be calculated annually or as required by RMP-15.

2.2 Transmission

This procedure applies to all PG&E and Standard Pacific Gas Line, Inc. (StanPac):

- Gas Transmission Pipeline Facilities
- Regulating Station Facilities
- PG&E-defined Gas Gathering-Local Transmission (GG-LT) Lines

2.3 Distribution

This procedure applies to all PG&E-defined distribution piping, equipment, and appurtenances operating above 60 psig for the assessment of risk per RMP-15.

3.0 INTRODUCTION

The risk management process gathers reviews and integrates data to calculate risk, prioritizes preventive and mitigative measures, and monitors for operational changes that may require additional actions. This process is applied annually to assure the ongoing integrity of all pipelines specified in Section 2.

RMP-01 describes the calculations for overall risk which is the product of the likelihood of failure (LOF) and consequence of failure (COF) potentially arising from the nine pipeline threats as defined in ASME B31.8S-2004. The nine threats are organized by failure mode grouping. The threats and the associated RMPs that contain the threat algorithms are as follows.

3.1 Time-Dependent Threats

1. External corrosion (EC): see RMP-02
2. Internal corrosion (IC): see RMP-02
3. Stress corrosion cracking (SCC): see RMP-02

3.2 Stable Threats

1. Manufacturing related defects (M): see RMP-05
2. Construction, including welding/fabrication-related (C): see RMP-05
3. Equipment failure (E): see RMP-19

3.3 Time-Independent Threats

1. Third party damage (TPD): see RMP-03
2. Incorrect operations (IO): see to RMP-19
3. Weather-related and outside force (WROF): see RMP-04

Where Manufacturing and Construction are handled together, they are designated as M&C.

4.0 ROLES AND RESPONSIBILITY

Specific responsibilities for ensuring compliance with this procedure are as follows:

Title	Reports to:	General Responsibilities
Manager of Risk Management Engineering	Director of Transmission Integrity Management	• Review and approve selection of Steering Committee Chairperson and membership
Supervisor of Risk Management	Manager of Risk Management Engineering	• Supervise completion of work (schedule/quality) • Monitor compliance with procedure and take corrective actions as necessary • Assign qualified individuals • Ensure training of assigned individuals

Title	Reports to:	General Responsibilities
Steering Committee Chairperson	Various	• Arrange meetings • Review procedure with steering committee per RMP-01 • Provide meeting minutes • Ensure action items are completed
Steering Committee Members (Subject Matter Experts)	Various	• Attend meetings as requested by Steering Committee Chairman • Review and direct procedure
Risk Management Engineers	Supervisor of Risk Management	• Perform calculations per procedure

5.0 TRAINING AND QUALIFICATIONS

5.1 Training

Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training	How Often
Supervisor of Risk Management	Procedure review of RMP-01	• Upon initial assignment • Once each calendar year
Steering Committee Chairperson	Procedure review of RMP-01	• Upon initial assignment • As part of steering committee meeting once each calendar year • As changes are made to the procedure
Steering Committee Members (Subject Matter Experts)	Steering Committee requirements of RMP-01	• As part of steering committee meeting once each calendar year
Risk Management Engineers	Procedure Review of RMP-01 and RMP-06	• Upon initial assignment • Once each calendar year • As changes are made to the procedure

5.2 Qualifications

See RMP-06 and RMP-15 for qualification requirements.

6.0 STEERING COMMITTEES

For each major component of the risk management program, a Steering Committee shall be established to provide technical review and input to the program. The Steering Committees are as follows, with threat assignments in parentheses:

- Time-Dependent Threats (EC, IC, SCC)
- Manufacturing and Construction (M&C)
- Equipment Failure (E)
- Third-Party Damage (TPD)
- Incorrect Operations (IO)
- Weather-Related and Outside Forces (WROF)
- Consequence of Failure (COF)

The first six steering committees are collectively the Likelihood of Failure committees. The threats of EC, IC, and SCC are addressed together by the Time-Dependent Threats steering committee. The threats of Manufacturing and Construction are addressed together by the M&C steering committee. The other threats have separate steering committees.

6.1 Steering Committee Requirements

Requirements for the Steering Committees are as follows:

6.1.1 Steering Committee Chairpersons

For each steering committee, the Manager of Risk Management, with the concurrence of the Supervisor of Risk Management, shall assign a Steering Committee Chairperson, except as noted by RMP-15. The Steering Chairperson is responsible for the adherence to this procedure.

6.1.2 Steering Committee Members

The Steering Committees shall be made up of at least five individuals with expertise in the particular subject matter. It is the responsibility of the Supervisor of Risk Management, with the concurrence of the Manager of Transmission Integrity Management, to select individuals with knowledge and experience in the steering committee's subject matter. A list of the current membership shall be documented.

6.1.3 Schedule and Scope

The steering committees shall meet at least once each calendar year to review and approve the methodology used to calculate risk, and to determine whether changes are advisable.

6.1.4 General assignments

At each meeting, the steering committees shall:

- Review the overall process of risk calculations described by this procedure and document their evaluations

- Review the requirements for conducting a steering committee meeting in the appropriate location
- Document the discussions and findings of steering committee meetings in the appropriate location

6.1.5 Specific assignments

Steering Committees shall validate the risk analysis results to assure that the methods used have produced results that are consistent with Company operations.

The LOF Steering Committees shall, at a minimum:

- Review risk algorithm output
- Review relevant performance metrics
- Review relevant industry data
- Review incident reports
- Ensure that pertinent regulatory advisories are included
- Ensure that role of mitigation is appropriately included
- Review weightings within the LOF factors
- Propose and document changes that may be needed in the risk calculation algorithms
- Perform procedures per this document and related documents
- Determine whether any new factors or data sets should be incorporated into the algorithm to better reflect LOF

The COF Steering Committee shall review, at a minimum:

- Risk algorithm output
- Relevant performance metrics
- Relevant industry data
- Incident reports
- Pertinent regulatory advisories
- Weightings within the COF factors
- Changes that may be needed in the risk calculation algorithms
- Relevant procedure per this document and related documents
- Whether any new factors or data sets should be incorporated into the algorithm to better reflect COF

6.2 Algorithm responsibility

The steering committees shall review procedures applicable to the threats as follows:

- **The algorithm for the threats of EC, IC, and SCC** shall be calculated per the direction of the Time-Dependent Threat Steering Committee, as described in RMP-02.
- **The algorithm for the threats of M&C** shall be calculated per the direction of the M&C Threat Steering Committee, as described in RMP-05.

- **The algorithm for the threat of E** shall be calculated per the direction of the Equipment Failure Threat Steering Committee, as described in RMP-19.
- **The algorithm for the threat of TPD** shall be calculated per the direction of the TPD Threat Steering Committee, as described in RMP-03.
- **The algorithm for the threat of IO** shall be calculated per the direction of the IO Threat Steering Committee, as described in RMP-19.
- **The algorithm for the threat of WROF** shall be calculated per the direction of the WROF Threat Steering Committee, as described in RMP-04.
- **The algorithm for the COF** shall be calculated per the direction of the COF Steering Committee, as described in RMP-01.

7.0 Data Gathering

Comprehensive pipeline and facility knowledge is essential to understanding the risk drivers that can affect an HCA segment. No one source of information is sufficient to make a reasonable assessment of risk; therefore, this information is gathered from numerous sources and is integrated for risk assessment. Data elements for each of the nine threat categories are as specified in ASME B31.8S and described in RMP-06.

7.1 Dataset Update

Risk is calculated based on an inventory of assembled datasets which are gathered by a variety of processes and with varying timeframes. New information may include, but is not limited to:

- Changes in surroundings, including population near a pipeline
- Changes to system operating characteristics that could affect safety margins
- The number of customers out of service
- Gas load
- Seismic information from the U.S Geological Survey (USGS)
- Updated environmentally-sensitive areas
- Maintenance, operation and mitigation results

Updates to the datasets are necessary for risk evaluations to reflect the operating conditions of the pipeline. The table below lists the minimum update cycles for data used in the risk assessment process.

Table 1. TABLE 1. UPDATE CYCLES

Category	Data	Minimum Update Interval
Attribute Data	See RMP-06 list	As made available in the company's data systems
Construction Data	See RMP-06 list	As made available in the company's data systems
Operational	Third party dig-ins	As submitted, annually
	Leak reports	As submitted, annually
	Other datasets, per RMP-06	As submitted, annually
Operational (geotechnical or land related)	Seismic (vertical or horizontal ground acceleration)	5 years
	Slope stability	5 years
	Liquefaction	5 years
	Water crossing	10 years
	Water crossing (navigable waterways)	As available
	Seismic (fault crossing)	5 years
	Land base*	As updates are submitted from the company-contracted land base vendor
Other	Electric transmission (internal)	As made available in the company's data systems
	Other (foreign) pipelines/ facilities	As available
	Public awareness information	Annually
Inspection Data	Other per RMP-06	As made available in the company's data systems
	HCA information including identified sites	Annually

* Land base information includes airports, roads, highways, railroads, water crossings (other than navigable waterways), parks, etc.

8.0 RISK DETERMINATION

8.1 Risk

Risk shall be defined as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF):

$$\textit{RISK} = \textit{LOF} \times \textit{COF}$$

(Equation 1)

In general, information used to calculate risk is obtained from PG&E's Geographical Information System (GIS). Exceptions are noted within Risk Management procedures. In special cases, updated information is made available from other sources, such as from pipeline engineers, in-line inspection (ILI) reports, corrosion engineers, or district personnel.

8.2 Calculation Methodology

The approach used to calculate risk is a relative risk assessment model. Relative risk values are produced by this methodology. The scoring shall be based on direction from appropriate Steering Committees and performed by the Risk Engineers.

Risk is calculated per this procedure for all pipeline segments. A pipeline segment is defined as a length of contiguous pipeline with the same piping specification, class location, and Integrity Management HCA designation.

Risk values for equipment or appurtenances (including drips, blow downs, stubs, crossties, dual feeds, or other equipment or appurtenances) are not calculated independently since; each appurtenance takes on the risk value calculated for its associated pipe segment, per PHMSA IM FAQ 84. All equipment, appurtenances, and features along the pipeline are a part of the segment and may govern the assignment of points for the entire segment.

Criteria that the steering committees consider significant for determining the threat's LOF and COF are expressed in points. Negative points may be assigned where current assessments confirm pipeline integrity and/or mitigation efforts have reduced susceptibility to a threat. The total value of each LOF shall not be less than zero.

The risk calculation includes these steps:

1. Accumulating data as described in this document and RMP-06
2. Determining LOF for each pipeline segment.
3. Determining COF for each pipeline segment.
4. Calculating risk for each pipeline segment based on the product of LOF and COF, where the LOF of each threat factor has been normalized
5. Review and validation of results

8.3 Likelihood of Failure

Likelihood of failure (LOF) is the relative measure of the probability that a pipe will fail.

The formula for calculating LOF is:

$$LOF = EC + IC + SCC + TPD + WROF + M\&C + E + IO$$

(Equation 2)

where

- The LOF is the summation of the normalized value of the likelihood of failure for each pipeline threat category.
- The likelihood of failure for each pipeline category is based upon individual factors contributing to the likelihood for each mode of failure. These factors are defined as algorithms in separate risk management procedures, as follows:
  - EC, IC, and SCC threat categories are defined per RMP-02
  - TPD threat category is defined per RMP-03
  - WROF threat category is defined per RMP-04
  - M&C threat categories are defined per RMP-05
  - E and IO threat categories are defined per RMP-19.

If new threat categories are identified for the determination the LOF, they will be submitted to the Consequence of Failure Steering Committee for inclusion in the risk calculations.

Threat interaction is acknowledged in the summations of the individual threat scores. Further evaluation for possible threat interaction is done by examination of combinations of certain threat scores.

The values used to determine when additional attention is warranted are set by the steering committee teams using comparable statistics from other pipeline segments and/or other factors.

8.4 Consequence of Failure

Consequence of failure (COF) shall be defined as the sum of the following weighted consequence categories: Impact on Population (IOP), Impact on the Environment (IOE), and Impact on Reliability (IOR).

8.4.1 Weighting

Each of the COF categories shall be weighted in proportion to the impact of a failure. IOP shall be weighted 50%, IOE shall be weighted 10%, and IOR shall be weighted 40%.

$$COF = [0.50(IOP) + 0.10(IOE) + 0.40(IOR)]\ FSF$$

(Equation 3)

where

IOP = Impact on Population (subsection 8.4.2 of this procedure)

IOE = Impact on Environment (subsection 8.4.3 of this procedure)

IOR = Impact on Reliability (subsection 8.4.4 of this procedure)

FSF = Failure Significance Factor (subsection 8.4.5 of this procedure)

The weightings of each of the COF categories are reviewed and approved by the COF Steering Committee. The consequences are expressed in points, as described in subsections 8.4.2, 8.4.3, 8.4.4, and 8.45, below.

8.4.2 Impact on Population (IOP)

The IOP contribution to COF shall be the sum of contributions for the following factors, where the contribution is the assigned points multiplied by the weighting.

A) **Population density in proximity to pipeline factor** (35% weighting)
Points are assigned as follows:

Criteria		Points	Contrib.
Class Location as defined by 49 CFR 192.5	Class 1	10	3.5
	Class 2	40	14
	Class 3	70	24.5
	Class 4	100	35

B) **Pipeline proximity[1] factor** (45% weighting)
Points shall be awarded once per criterion type, but more than one criterion can apply.
Points for each criterion are cumulative and are assigned as follows:

Criteria	Points	Contrib.
Identified sites per RMP-08	100	45
Railroads, BART, and light rail tracks	30	13.5
Highway[2]	40	18
Commercial airports[3]	50	22.5
No feature	0	0

[1] Proximity is defined as the larger of 300 ft radius or the PIR per RMP-08.
[2] Highways are Class 1, 2, and 3 roads as defined in the land base data set.
[3] Airports are as defined in the land base data set.

C) **Impact Zone Factor** (20% weighting)
Points are assigned as follows:

$$\text{Points} = 1 + \pi[(0.69)(OD^2 * MAOP)^{1/2}]^2(1.3X10^{-5}), \text{ not to exceed } 20$$

8.4.3 Impact on Environment (IOE)

The IOE contribution to COF is the sum of contributions for the following factors, where the contribution is the assigned points multiplied by the weighting.

A) **Water crossing factor** (20% weighting).
Points are assigned as follows:

Criteria	Points	Contrib.
Presence of water crossing	100	20
No water crossing	0	0

B) **Environmentally-sensitive area factor** (80% weighting)
Points shall be awarded once per criterion type, based upon proximity* of pipeline, but more than one criterion can apply.
Points for each criterion are cumulative and are assigned as follows:

Criteria	Points	Contrib.
State or national park	70	56
Wildlife preserve	70	56
Navigable waterway	90	72
Other protected area	70	56
No environmentally sensitive area	0	0

*Within 100 yards or PIR (as defined in RMP-08), whichever is greater and unless otherwise noted.

8.4.4 Impact on Reliability (IOR)

The IOR contribution to COF is the sum of contributions for the following factors, where the contribution is the assigned points multiplied by the weighting.

A) **Reliability impact factor** (35% weighting)
Impact on gas load served by PG&E in the event of a pipe failure.
Points are assigned for gas load* as follows:

Criteria	Points	Contrib.
Known gas load	10 + (Gas Load/ 500)**	≤35
Unknown gas load	20	7

* Gas Load (MCF/Day) is the higher of an Average Summer Day (ASD) or an Average Winter Day (AWD), as provided by Transmission System Planning; does not include Abnormal Peak Days (APD).
** Not to exceed 100.

B) **Outage Factor** (55% weighting)
Number of potential services experiencing a gas service outage in the event of a pipe failure based upon the Gas Transmission planning model.
Points are assigned as follows:

Criteria	Points	Contrib.
Known number of customers affected	10 + (number of customers /500)*	≤55
Unknown number of customers affected	20	11

* Not to exceed 100.

C) **Critical Facility Factor** (10% weighting).
If there are multiple critical facilities, only the facility with the highest points is

included in the point total.
Points are assigned as follows:

Criteria	Points	Contrib.
Liquid fuel pipelines[1]	100	10
Other gas pipelines[2]	80	8
Electric transmission lines[1]	80	8
No critical facilities	0	0

[1] Within 30 meters of gas pipeline.
[2] Within 10 meters of gas pipeline.

8.4.5 Failure Significance Factor (FSF)

FSF represents the relative likelihood of leak, rather than rupture, and the existence of wall-to-wall conditions which would make the consequences of a leak more severe. The FSF will be assigned as 1.0 or it can be assigned as 0.5 if the pipe operating stress is less than 20% of SMYS, wall-to-wall paving conditions are verified and meets all the following criteria:

1. Depth of cover is more than 12 inches
2. The pipeline segment is not located within 300 ft. of a switchyard
3. The pipeline segment OD is less than 4.5 inches, **or** the pipe diameter is greater than 4.5" and is not located within 300 feet of an identified site, as defined by 49 CFR Part 192.903
4. The pipeline was installed after 1962 and has a ground acceleration of less than 0.5g.
5. The pipeline was installed after 1962 and has a ground acceleration of 0.2 g or greater and is not in an area susceptible to significant ground movement per Figure A-6: Construction Threat Identification in RMP-16.

9.0 Documentation

The decisions of the threat steering committees shall be documented by meeting minutes that detail the rationale of the algorithm decisions. The minutes shall be maintained within the Risk Management files.

The data used for the risk assessment is contained in the Risk Calculations for a given year (documented in the Risk and Threat spreadsheet).

The results of the risk assessment process shall be documented in the Baseline Assessment Plan (BAP).

The documentation shall be maintained for the life of the facilities in accordance with 49 CFR 192.947.

PACIFIC GAS AND ELECTRIC COMPANY

GAS OPERATIONS

PUBLIC SAFETY & INTEGRITY MANAGEMENT

Risk Management Procedure
Procedure No. RMP-02
Revision 7
Time-Dependent Threat Algorithm

Gas Transmission Integrity Management Program
for PG&E and Standard Pacific Gas Line, Inc.

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Rev. No.	Date	Description	Prepared By	Approved By	Approved Manager, System Integrity
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Rev No	Date	Description	Prepared by	IM Risk Supervisor	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
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Rev No	Date	Description	Prepared by	Risk Management Supervisor	Integrity Management Engineering Manager	Director, Transmission Integrity Management	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
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1.0 PURPOSE

The purpose of this procedure is to establish the corrosion time-dependent threat category algorithm for the determination of Likelihood of Failure for PG&E's Gas Transmission and Distribution Integrity Management Program, described in RMP-06 and RMP-15.

2.0 SCOPE

2.1 Transmission

This guideline applies to all of PG&E's gas transmission pipeline facilities and is to be used in conjunction with RMP-01, Risk Management Procedure. The algorithms described in this procedure are used for transmission pipelines and associated appurtenances, per RMP-01. The results are communicated to the Transmission Integrity Management Program (TIMP), whose risk management processes are designed to meet the requirements of 49 CFR 192 Subpart O. The TIMP group performs a risk assessment to identify and prioritize risks for transmission pipelines per RMP-06.

2.2 Distribution

The algorithms described in this procedure are also used for distribution pipelines and associated appurtenances operating over 60 psig. The results are communicated to the Gas Distribution Integrity Management Program (DIMP), whose risk management processes are designed to meet the requirements of 49 CFR 192 Subpart P. The DIMP group performs a risk assessment to identify and prioritize risks for distribution pipelines per RMP-15.

3.0 INTRODUCTION

As required by RMP-01, RMP-06, and RMP-15, this procedure (RMP-02) supports the calculation of Likelihood of Failure (LOF).associated with potential time-dependent threats. B31.8S identifies nine pipeline threat categories according to the time factors and failure mode. The time-dependent threats are external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC).

RMP-01 describes Risk as the product of the LOF and the Consequence of Failure (COF). A relative risk assessment model is used to establish risk for all pipeline segments within the scope of RMP-01.

LOF is defined as the sum of the following threat categories:

- External corrosion (EC)
- Internal corrosion (IC)
- Stress corrosion cracking (SCC)
- Third party damage (TPD)
- Weather-related and outside forces (WROF)

- Manufacturing (M)
- Construction, including welding/fabrication-related risks (C)
- Equipment (E)
- Incorrect operations (IO)

  Where Manufacturing and Construction are handled together, they are designated M&C.

See RMP-15 for equivalent identified distribution threats, per 49 CFR 192.1007.

For each threat category, the appropriate steering committee identifies the significant factors that influence the LOF for each threat. (For a discussion of steering committees, see RMP-01.)

4.0 ROLES AND RESPONSIBILITY

The Integrity Management Group is responsible for managing risk within the scope of this procedure. The Integrity Management Group shall establish and manage the risk of each pipeline facility using methodologies that are

- consistent with industry practice
- acceptable to regulatory agencies
- appropriate for PG&E's gas facilities
- in conformance with this procedure

Specific responsibilities for ensuring compliance with this procedure are as follows.

Title	Reports to	Responsibilities
Risk Management Supervisor	Integrity Management Risk Manager	• Supervise completion of work (schedule/quality) • Monitor compliance with procedure and take corrective actions as necessary for transmission pipe • Analyze and communicate risk assessment results • Ensure training of assigned individuals
Risk Management Engineers	Risk Management Supervisor	• Perform calculations per procedure • Analyze and communicate risk assessment results • Identify need for changes

5.0 TRAINING AND QUALIFICATIONS

5.1 Training

Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training	How Often
Risk Management Supervisor	Procedure review of RMP-01 and RMP-02	• Upon initial assignment • Once each calendar year
Time-Dependent Steering Committee Chairman	Procedure review of RMP-01 and RMP-02	• Upon initial assignment • Once each calendar year • As changes are made to the procedure
Time-Dependent Steering Committee Members (Subject Matter Experts)	Review RMP-02 and Steering Committee requirements of RMP-01	• Once each calendar year at the time of the steering committee meeting
Risk Management Engineers	Per RMP-06 and RMP-15 requirements; review RMP-02	• Upon initial assignment • Once each calendar year • As changes are made to the procedure

5.2 Qualifications

See RMP-06 and RMP-15 for qualification requirements.

6.0 ALGORITHMS

The LOF for EC, IC, and SCC are calculated independently. The algorithms are described in sections 6.1-6.3, below.

Other risk factors to transmission and distribution pipeline segments operating above 60 psig may be considered by the Time-Dependent Steering Committee based upon new available information and included in the algorithm. These determinations are regularly reviewed and subject to change per RMP-01.

6.1 EC Threat Algorithm

Scoring for the EC threat algorithm shall be calculated per the direction of the Time-Dependent Steering Committee. The committee has determined that the factors listed as A through M of this section are significant for determining LOF due to EC.

Before applying the algorithm, the Risk Management Engineer shall evaluate the list of factors and determine whether any factors should be added, removed or modified. Changes to factors, point values, and other aspects of the risk algorithm are controlled by RMP-01 and the Management of Change (MOC) process described in RMP-06.

The LOF for EC is calculated by:

1. Assigning points to each factor based on maintenance and operating records, assessment results, and pipeline attribute information.

2. Multiplying the assigned points by the weighting for the factor, as established by the Time-Dependent Steering Committee. This product is the *contribution* for the factor.

3. Summing the factor contributions. This sum is the LOF for EC.

Following are the factors for EC.

A) **Soil Resistivity Factor** (4% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Less than or equal to 500 Ohm-cm*	100	4
501 to 1000 Ohm-cm	80	3.2
1001 to 2000 Ohm-cm	60	2.4
2001 to 4000 Ohm-cm	40	1.6
4001 to 10,000 Ohm-cm	20	0.8
Above 10,000 Ohm-cm	10	0.4

* Default

B) **Corrosion Survey Criteria Factor** (5% weighting)
Points shall not be assigned for CIS surveys of more than 10 years.
Points are assigned as follows:

Criteria	Points	Contrib.
No CIS* readings available**	50	2.5
CIS available and no mitigative measures are required	-100	-5
CIS available and additional mitigative measures are required	300	15

* CIS = Close Interval Survey. This information is provided to the Risk Management Program by the Corrosion Engineer. The Corrosion Engineer evaluates the CIS data, considering survey age, quality, and amount of variation in the CIS measurement profile.
**Default

C) **Coating Visual Inspection Factor*** (8% weighting)
Points are assigned as follows:

Criteria		Points	Contrib.
Severely disbonded (Poor)		100	8
Locally damaged, disbonded (Fair)		50	4
Superficial damage only (Good)		20	1.6
Intact and bonded (Excellent)		10	0.8
Bare pipe or no inspection, and coating age is…	5 years or less	11	0.88
	More than 5 years and less than or equal to 20 years	19	1.52
	More than 20 years and less than or equal to 30 years	29	2.32
	Over 30 years**	51	4.08

* Inspection data greater than 20 years old shall not be used unless the result was Fair or Poor. In such cases, points are assigned per the inspection.
** Default

D) **Casing Survey Factor** (3% weighting)
Points are assigned as follows, based on the most recent annual casing check:

Criteria	Points	Contrib.
No identified casing or gelled casing	0	0
An identified existing casing with no evidence of short	20	0.6
Electrically-shorted casing	100	3

E) **In-Line-Inspection (ILI) Factor** (5% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
No inspection performed	0	0
Inspection more than 10 years ago	-100	-5
Inspection more than 5, and less than or equal to 10 years ago	-300	-15
Inspection less than or equal 5 years ago	-600	-30

F) **External Corrosion Leak Rate Factor** (19% weighting)
Points are assigned as follows*:

Criteria	Points	Contrib.
Leak in last 5 years	100	14
Leak more than 5, and less than or equal to 10 years ago	80	11.2
Leak more than 10 years ago	50	7
No reported leaks	0	0

* Points apply to all pipe segments of similar vintage and coating type within a 1-mile radius of a leak.

G) **Coating Design Factor** (8% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Coatings susceptible to shielding *	100	8
Coatings not known to be susceptible to shielding **	10	0.8
Bare	30	2.4
Paint	10	0.8
Default (installation date 1960 or later; assume tape or equivalent)	100	8
Default (installation date earlier than1960; assume HAA or equivalent)	10	0.8

* Coal tar, MECH (abrasion resistance over coating), Plastic, Steel, Extruded Plastic, Tape.
** HAA, Wax, Concrete, Somastic, FBE, Paint, Power Crete, Protal, Dev-Grip, Del-Tar.

H) **DC/AC Interference Factor** (10% weighting)
For scoring purposes, Risk Management Engineer and Corrosion Engineer will jointly determine level (high or medium) for each potential location of interference. Both instantaneous voltage/current measurements and fluctuations over time should be considered.
Points are assigned as follows:

Criteria	Points	Contrib.
High or medium voltage and/or current within 500' of a gas pipeline without cathodic protection	100	10
High or medium voltage and/or current within 500' of a gas pipeline with cathodic protection	50	5
No high or medium voltage and/or current	0	0

I) **Coating Age Factor** (5% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Older than 30 years *	100	5
Older than 20 years, and 30 years or less	80	4
Older than 10 years, and 20 years or less, or uncoated	30	1.5
10 years or less	10	0.5

*Default

J) **Operating Stress Factor** (8% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
60% of SMYS or greater	100	8
50% of SMYS or greater, up to 60%	80	6.4
40% of SMYS or greater, up to 50%	50	4
30% of SMYS or greater, up to 40%	30	2.4
20% of SMYS or greater, up to 30%	10	0.8
Less than 20% of SMYS	5	0.4

K) **Pipe Visual Inspection Factor*** (10% weighting)
Points are assigned as follows:

Criteria		Points	Contrib.
Heavy pitting or gouging (Poor)		100	10
Light pitting or gouging (Fair)		50	5
Heavy rusting		20	2
Light rusting (Good)		10	1
No pitting or rusting (Excellent)		0	0
Pipe age is…	5 years or less	0	0
	More than 5 years, and less than or equal 20 years	10	1
	More than 20 years, and less than or equal 30 years	20	2
	Over 30 years	40	4

* Inspection data greater than 20 years old or otherwise of limited usefulness (as determined by Risk Management Engineer) shall not be used unless the condition was Fair or Poor. In such cases, points are assigned per the inspection, regardless of when the inspection was performed, until information is updated.

L) **Pressure Test (PT) Factor** (5% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Not tested for assessment	0	0
Age of Pressure Test is within the reassessment interval as defined in ASME B31.8S Table 3	-200	-10
PT age exceeds ASME B31.8S Table 3 requirements for Hydrostatic Test Interval years by at most 3 years	-100	-5
PT exceeds ASME B31.8S Table 3 requirements for Hydrostatic Test Interval by more than 3 years	0	0

M) **External Corrosion Direct Assessment (ECDA) Factor** (10% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
ECDA completed within relevant period*	-200	-20
ECDA not completed within relevant period	0	0

* For scoring purposes, Risk Management Engineer and Corrosion Engineer will jointly determine 'relevant period' for each ECDA, considering findings, changes since the assessment, and other factors.

6.2 IC Threat Algorithm

Following are the factors for determining LOF due to IC. Where multiple criteria apply, the criterion with the highest point value is used. In assigning points, the Risk Management Engineer and Corrosion Engineer shall also determine relevance of nearby or related data upstream and downstream, considering likelihood that the conditions precipitating the corrosion may also be occurring on the subject pipeline segment.

Scores apply to pipeline segments in close proximity and under the same gas source or operating conditions.

A) **IC-Related Leaks or Ruptures Factor** (17% weighting)
Points are assigned as follows:

Criteria		Points	Contrib.
Time since leak or rupture is…	10 years or less	100	17
	More than 10 years, and less than or equal to 20 years	80	13.6
	More than 20 years, and less than or equal to 30 years	60	10.2
	Over 30 years	40	6.8
No leaks or ruptures have occurred		0	0

B) **Inspections Factor** (22% weighting)
If a leak or rupture has occurred, "Internal Corrosion history" shall be selected in the table below.
Points are assigned as follows:

Criteria		Points	Contrib.
Internal corrosion history **		100	22
No inspection performed*		60	13.2
No internal corrosion identified…	in a random location	40	8.8
	in a low spot/location where corrosion is most likely	0	0

* Default
** Consult SME to determine applicability of previous IC findings to determine the nearby segments that may have similar IC condition.

C) **Features/Operating Conditions Factor** (8% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
A dead leg is present	100	8
A drip is present	80	6.4
An offset, bottom tap, or built-in low spot is present	60	4.8
A flange, mechanical coupling, or wrinkle is present (no drips, dead legs, offsets, or built-in low spots) or other pipe feature that may contribute to internal corrosion	40	3.2
The pipeline or a section of the pipeline that exhibits sporadic flow conditions as recognized by IC group	40	3.2
None of these features	0	0

D) **Drip/Bottom Tap Maintenance Factor** (5% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Drips/bottom taps that exhibit presence of liquids	100	5
Drips/bottom taps are present but no liquids have been identified.	80	4
No known drips or bottom taps *	0	0

* Default

E) **Time in Operation Factor** (5% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Over 50 years	100	5
More than 30 years, and less than or equal to 50 years	80	4
More than 10 years, and less than or equal to 30 years	40	2
10 years or less	0	0

F) **Pigging Factor** (5% weighting)
Points are assigned as follows:

<table>
<tr><th colspan="2">Criteria</th><th>Points</th><th>Contrib.</th></tr>
<tr><td colspan="2">The pipeline is not piggable or is never maintenance pigged.</td><td>0</td><td>0</td></tr>
<tr><td rowspan="2">The pipeline is piggable…</td><td>and has been maintenance-pigged at periods greater than a year</td><td>-40</td><td>-2</td></tr>
<tr><td>and has been maintenance-pigged at least annually</td><td>-200</td><td>-10</td></tr>
</table>

G) **Liquids Factor** (10% weighting)
Liquids test data exceeding 2 years in age will not be used unless data indicates presence of water. Consult SME to determine applicability of previous positive liquids tests.
Points are assigned as follows:

Criteria	Points	Contrib.
Liquids were found and tested positive for water	100	10
Liquids were found and were not tested for water	80	8
Liquids were found and testing found no water is present	20	2
Liquids were not found or pipeline segment does not exhibit the potential for the presence of water	0	0
Pipeline segment is not checked for the presence of liquids and exhibits the potential for the presence of water	70	7

H) **Gas Monitoring Factor** (5% weighting)
This factor considers the monitoring of the gas stream for potential corrosion-causing contaminants.

Gas monitoring data exceeding 2 years in age will not be used unless data indicates results that are out of specification. Consult SME to determine applicability of previous out-of-specification results.

If data are more than 2 years old and the results are within specification, then "The transported gas is not being monitored" shall be selected.

If continuous gas monitoring is being performed, then data showing out-of-specification results for less than a total of 3 days in a month or 1 month in a year should not be used. However, the data may be used if the Risk Management Engineer and/or Corrosion Engineer determine that excursions may have led to an increased likelihood of internal corrosion.

If spot-testing is being performed, then all data should be used unless a recheck within two weeks of the out-of-specification results shows gas that is within specification.

Points are assigned as follows:

Criteria		Points	Contrib.
The transported gas is being monitored…	and all results do not meet specifications*	100	5
	and results meet specifications*	0	0
The transported gas is not being monitored		70	3.5

* Gas monitoring specifications:
H_2S Partial Pressure < 0.03 psi
CO_2 Partial Pressure < 7 psi
H_2O Water content < 7 lbs/mmscf

I) **Gas Source Factor** (5% weighting)
Points will be assigned to the segment downstream to the next pressure control facility, as follows:

Criteria	Points	Contrib.
The segment is transporting or has transported landfill gas	100	5
The segment is in a gathering area or is directly tied to a gathering area or producer	80	4
The segment is in or directly tied to a storage field	70	3.5
The segment is transporting or has transported coal bed methane, or gas from any other unconventional source	60	3
The segment is transporting or has transported gas from an LNG source	40	2
None of the above	0	0

J) **Solids Factor*** (10% weighting)
Solids test data exceeding 10 years in age will not be used unless data indicates presence of solids. Consult SME to determine applicability of previous positive solids tests.
Points are assigned as follows:

Criteria	Points	Contrib.
No information	100	10
Solids observed on internal surface of pipeline or recovered from pipeline	100	10
Pipeline has been cleaned and solids were removed in the previous 10 years	30	3
Pipeline has been cleaned and no solids observed on internal surface of pipeline nor recovered from pipeline	0	0

* Solids are defined as corrosion products, scale, sludge, sand, or other materials that can promote corrosion or are the result of corrosion.

K) **Bacteria Factor** (5% weighting)
Bacteria test data exceeding 2 years in age will not be used unless data indicates presence of bacteria. Consult SME to determine applicability of previous positive bacteria tests and significance of bacteria levels.
Points are assigned as follows:

Criteria	Points	Contrib.
Testing has found high levels of bacteria	100	5
Testing has found low levels of bacteria	40	2
Testing has not found bacteria	0	0
Testing for bacteria has not been performed.	60	3

L) **Corrosion Rate Monitoring Factor** (8% weighting)
Where corrosion probes are used and readings are recorded in increments shorter than 6 months, the highest 6-month average rate from all readings within 5 years shall be used. Consult SME to determine applicability and significance of corrosion rate tests.
High corrosion rate shall mean greater than or equal to 5 mpy, per NACE RP0775-2005.
Points are assigned as follows:

Criteria	Points	Contrib.
Testing has found high corrosion rates	100	8
Testing has found low corrosion rates	40	3.2
Testing has not found corrosion	0	0
Testing for corrosion has not been performed.	40	3.2

M) **Chemical Treatment Factor** (5% weighting)
This factor refers to chemical treatments that reduce the rate of IC. Consult SME to determine applicability and significance of chemical treatment.
Points are assigned as follows:

Criteria	Points	Contrib.
No chemical treatment plan currently in place	0	0
Biocide treatment plan is in place AND **is not** being monitored	-40	-2
Corrosion inhibitor treatment plan is in place AND **is not** being monitored	-80	-4
Biocide treatment plan is in place AND **is** being monitored	-100	-5
Corrosion inhibition plan is in place AND **is** being monitored	-200	-10

N) **Internal Coating or Lining Factor** * (8% weighting)
Consult SME to determine applicability and significance of coating or lining.
Points are assigned as follows:

<table>
<tr><th colspan="2">Criteria</th><th>Points</th><th>Contrib.</th></tr>
<tr><td colspan="2">No coating or lining has been installed</td><td>0</td><td>0</td></tr>
<tr><td rowspan="2">A coating has been applied…</td><td>and is less than or equal to 10 years old</td><td>-20</td><td>-1</td></tr>
<tr><td>and is greater than 10 years old</td><td>-100</td><td>-5</td></tr>
<tr><td colspan="2">A lining has been installed</td><td>-200</td><td>-10</td></tr>
</table>

6.3 SCC Threat Algorithm

This algorithm applies to gas transmission and distribution greater than 60 psig. Scoring for the SCC threat algorithm is calculated per the direction of the Time-Dependent Steering Committee.

Before applying the algorithm, the Risk Management Engineer shall evaluate the list of factors and determine whether any factors should be added, removed or modified. Changes to factors, point values, and other aspects of the risk algorithm are controlled by RMP-01 and RMP-06).

The LOF for SCC is calculated by:

1. Assigning points to each factor based on maintenance and operating records, assessment results, and pipeline attribute information.
2. Multiplying the assigned points by the weighting for the factor, as established by the Corrosion Steering Committee. This product is the *contribution* for the factor.
3. Summing the factor contributions of the High pH SCC and the Near- Neutral pH SCC independently and applying the higher value as the LOF of SCC.

If multiple criteria apply within any one factor, the criterion with the highest point value is used.

6.3.1 High-pH SCC Factors

The committee has found the factors listed as A through J of this section significant for determining LOF due to high-pH SCC.

A) **Historical Location of Potential SCC Factor** (6% weighting)
Historical excavation and failure records that indicate the presence of SCC and exceed 10 years in age will not be used. Consult SME to determine applicability of previous SCC findings.
Points are assigned as follows:

Criteria	Points	Contrib.
Review of historical documents identifies SCC locations	100	6.0
Review of historical documents does not identify SCC locations	0	0

B) **Coating Type Factor** (12% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Unknown	100	12.0
Coal tar	100	12.0
Asphalt	90	10.8
Tape	75	9.0
Fusion-bonded epoxy (FBE)	0	0
Extruded polyethylene	0	0
Other (e.g. wax, paint, etc.)	75	9.0

C) **External girth weld coating type factor** (3% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Unknown	100	3.0
Coal Tar	100	3.0
Asphalt	90	2.7
Tape or shrink-sleeve	75	2.3
Fusion-bonded epoxy or two-part epoxy	0	0
Other (e.g. wax, paint, etc.)	75	2.3

D) **Coating Condition Factor** (13% weighting)
Follow the instructions for coating grading from the inspection reports (e.g., Forms A and Forms H) with particular attention to coating conditions that favor SCC. Points are assigned as follows:

Criteria	Points	Contrib.
Poor	50	6.5
Fair	30	3.9
Good	15	1.95
Excellent	0	0
Unexamined or Unknown	Factor E x 0.5	Weighting x Factor E x 0.5

E) **Pipe Age Factor** (6% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Unknown pipe age	100	6.0
Pre-1943	80	4.8
1943-1983	100	6.0
1984-2002	60	3.6
2003-present	10	0.6

F) **Current Operating Stress Factor** (16% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Greater than 60% of SMYS	100	16.0
40% to 60% of SMYS	25	4.0
Less than 40% of SMYS	0	0

G) **Historic Operating Stress Factor** (8% weighting)
Segments currently operating at lower stress levels but has previously operated at levels above 60% of SMYS.
Points are assigned as follows:

Criteria	Points	Contrib.
Has historically operated above 60% of SMYS	50	4.0
Has not historically operated above 60% of SMYS	0	0
Historic operating pressure unknown	0.5x factor F	Weighting x 0.5 x factor F

H) **Pressure Cycle Factor** (6% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Segments with known significant cycling history	100	6.0
Segments without a known significant cycling history	0	0
No pressure cycle counting is performed *	50	3.0

* Default

Note: If the pipeline operates at more than 60% SMYS, then rain flow cycle counting should be performed to determine the pressure cycle aggressiveness.

I) **Distance From Compressor Station Factor** (10% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Less than or equal to 20 miles downstream of compressor station	100	10.0
Greater than 20 miles	0	0

J) **Operating Temperature Factor** (20% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Greater than 140 degrees Fahrenheit	100	20.0
Between 120 and 140 degrees Fahrenheit **	80	16.0
Between 100 and 120 degrees Fahrenheit	60	12.0
Between 80 and 100 degrees Fahrenheit	40	8.0
Between 60 and 80 degrees Fahrenheit	20	4.0
Less than 60 degrees Fahrenheit and unknown*	0	0

* Default
** Applies to pipe segments located less than or equal to 20 miles downstream of compressor station for unknown operating temperature.

6.3.2 Near-neutral-pH SCC factors

The committee has found the factors listed as A through J of this section significant for determining LOF due to near-neutral-pH SCC.

A) **Historical Location of Potential SCC** (6% weighting)
Historical excavation and failure records that indicate the presence of SCC and exceed 10 years in age will not be used. Consult SME to determine applicability of previous SCC findings.
Points are assigned as follows:

Criteria	Points	Contrib.
Review of historical documents reveals potential SCC location	100	6.0
Review of historical documents does not reveal potential SCC location	0	0

B) **Coating Type Factor** (14% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Unknown	150	21.0
Tape	150	21.0
Asphalt	40	5.6
Coal Tar	35	4.9
Fusion-bonded epoxy or two-part epoxy	0	0
Extruded Polyethylene	0	0
Other (e.g. wax, paint, etc.)	40	5.6

C) **External girth weld coating type factor** (4% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Unknown	150	6.0
Tape or shrink-sleeve	150	6.0
Asphalt	40	1.6
Coal Tar	35	1.4
Fusion-bonded epoxy or two-part epoxy	0	0
Other (e.g. wax, paint, etc.)	40	1.6

D) **Coating Condition Factor** (6% weighting)
Follow the inspection report (e.g., Forms A and H) instructions for grading coating, with particular attention to coating conditions that favor SCC. Points are assigned as follows:

Criteria	Points	Contrib.
Poor	50	3.0
Fair	30	1.8
Good	15	0.9
Excellent	0	0
Unexamined or Unknown	Factor E x 0.5	Weighting x Factor E x 0.5

E) **Pipe Age Factor** (9% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Unknown pipe age	100	9.0
Pre-1943	80	7.2
1943-1983	100	9.0
1984-2002	60	5.4
2003-present	10	0.9

F) **Current Operating Stress Factor** (9% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Greater than 60% SMYS	100	9.0
40% to 60% SMYS	60	5.4
Less than 40% SMYS	25	2.25

G) **Historic Operating Stress Factor** (6% weighting)
Segments currently operating at lower stress levels but has previously operated at levels above 60% of SMYS. Points are assigned as follows:

Criteria	Points	Contrib.
Has operated at a higher pressure	50	3.0
Has not operated at a higher pressure	0	0
Historic operating temperature unknown	Factor F x 0.5	Weighting x Factor F x 0.5

H) **Pressure Cycle Factor** (22% weighting)
Points are assigned as follows:

Criteria*	Points	Contrib.
Segments with known significant cycling history	100	22.0
Segments without a known significant cycling history	0	0
No pressure cycle counting is performed*	50	11.0

* Default

Note: If the pipeline operates at more than 60% of SMYS, then rainflow cycle counting should be performed to determine the pressure cycle aggressiveness.

I) **Distance From Compressor Station Factor** (7% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Less than or equal to 20 miles downstream of compressor station	100	7.0
Greater than 20 miles	0	0

J) **Stress Increasers/Concentrators Factor** (17% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Outer diameter to wall thickness ratio greater than 100	100	17.0
Outer diameter to wall thickness ratio between 30 and 100	25	4.3
Outer diameter to wall thickness ratio less than 30	0	0
Known or suspected instances of dents, gouges, certain appurtenances, or other stress concentrators	100	17

7.0 REFERENCES

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PACIFIC GAS AND ELECTRIC COMPANY

GAS OPERATIONS

PUBLIC SAFETY & INTEGRITY MANAGEMENT

Risk Management Procedure

Procedure No. RMP-03
Revision 7
Third Party Damage Threat Algorithm 7

Gas Transmission Integrity Management Program
for PG&E and Standard Pacific Gas Line, Inc.

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Concur: Date: 6/1/12
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Approved By: Date: 8/6/2012
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Rev. #	Date	Description	Prepared By	Approved By	Approved	
					Manager, System Integrity	
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1	3/14/03	Revised as shown		Redacted		
2	6/13/05	Revised as shown				
3	10/28/05	Revised as shown				
					Director, System Integrity & Gas Issues	
4	12/27/08	Reviewed and added DIMP			Bob Fassett	
					Manager, System Integrity	Director, System Integrity
5	12/28/09	Revised as shown			SEBE	RPF2

Rev #	Date	Description	Prepared by	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
6	3/26/12	Revised Weighting in Risk Calculation	Reda	SEBE	N/A	SLHB	RIT4

Rev #	Date	Description	Prepared by	Risk Management Supervisor	Integrity Management Engineering Manager	Director, Transmission Integrity Management	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
7	8/06/12	See Change Form	Reda	Redact	Redacte	B2BY	SLHB	RIT4

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1.0 PURPOSE

The purpose of this procedure is to establish the Third Party Damage Threat algorithm as part of the determination of Likelihood of Failure for PG&E's Gas Transmission and Distribution Integrity Management Program, described in RMP-06 and RMP-15.

2.0 SCOPE

2.1 Transmission

This guideline applies to all of PG&E's gas transmission pipeline facilities and is to be used in conjunction with RMP-01, Risk Management Procedure. The algorithm described in this procedure is for transmission pipelines and associated appurtenances, per RMP-01. The results are communicated to the Gas Transmission Integrity Management Program (TIMP), whose risk management processes are designed to meet the requirements of 49 CFR 192 Subpart O. The TIMP group performs a risk assessment to identify and prioritize risks for transmission pipelines per RMP-06.

2.2 Distribution

The algorithm described in this procedure is also used for distribution pipelines and associated appurtenances operating over 60 psig. The results are communicated to the Gas Distribution Integrity Management Program (DIMP), whose risk management processes are designed to meet the requirements of 49 CFR 192 Subpart P. The DIMP group performs a risk assessment to identify and prioritize risks for distribution pipelines per RMP-15.

3.0 INTRODUCTION

As required by RMP-01, RMP-06, and RMP-15, this procedure (RMP-03) supports the calculation of risk due to third party damage (TPD).

RMP-01 describes Risk as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). A relative risk assessment model is used to establish risk for all pipeline segments within the scope of RMP-01.

LOF is defined as the sum of the following threat categories:

- External corrosion (EC)
- Internal corrosion (IC)
- Stress corrosion cracking (SCC)
- Third party damage (TPD)
- Weather-related and outside forces (WROF)
- Manufacturing (M)
- Construction, including welding/fabrication-related risks (C)
- Equipment (E)
- Incorrect operations (IO)

Where Manufacturing and Construction are handled together, they are designated M&C.

See RMP-15 for equivalent identified distribution threats, per 49 CFR 192.1007.

For each threat category, the appropriate steering committee identifies the significant factors that influence the LOF for that threat. (For a discussion of steering committees, see RMP-01.)

4.0 ROLES AND RESPONSIBILITY

The Integrity Management Group is responsible for managing risk within the scope of this procedure. The Integrity Management Group shall establish and manage the risk of each pipeline facility using methodologies that are

- consistent with industry practice
- acceptable to regulatory agencies
- appropriate for PG&E's gas facilities
- in conformance with this procedure

Specific responsibilities for ensuring compliance with this procedure are as follows:

Title	Reports to	Responsibilities
Risk Management Supervisor	Integrity Management Engineering Manager	• Supervise completion of work (schedule/quality) • Monitor compliance with procedure and take corrective actions as necessary for transmission pipe • Analyze and communicate risk assessment results • Ensure training of assigned individuals
Risk Management Engineers	Risk Management Supervisor	• Perform calculations per procedure • Analyze and communicate risk assessment results • Identify need for changes

5.0 TRAINING AND QUALIFICATIONS

5.1 Training

Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training	How Often
Risk Management Supervisor	Procedure review of RMP-01 and RMP-03	• Upon initial assignment • Once each calendar year.
TPD Steering Committee Chairman	Procedure review of RMP-01 and RMP-03	• Upon initial assignment • Once each calendar year • As procedure is changed.
TPD Steering Committee Members (Subject Matter Experts)	Review RMP-03 and Steering Committee requirements of RMP-01	• Once each calendar year at the time of the steering committee meeting.
Risk Management Engineers	Per RMP-06 and RMP-15 requirements; review RMP-03	• Upon initial assignment • Once each calendar year • As procedure is changed.

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5.2 Qualifications

See RMP-06 and RMP-15 for qualification requirements.

6.0 THIRD PARTY DAMAGE THREAT ALGORITHM

Scoring for the TPD threat algorithm shall be performed per the direction of the Third Party Damage Steering Committee. The committee has determined that the factors listed as A through I of this section are significant for determining LOF due to TPD.

Before applying the algorithm, the Risk Management Engineer shall evaluate the list of factors and determine whether any factors should be added, removed or modified. Changes to factors, point values, and other aspects of the risk algorithm are performed per RMP- 01 and the Management of Change (MOC) process described in RMP-06.

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The LOF for TPD is calculated by:

1. Assigning points to each factor based on maintenance and operating records, assessment results, and pipeline attribute information.
2. Multiplying the assigned points by the weighting for the factor, as established by the TPD Steering Committee. This product is the contribution for the factor.
3. Summing the factor contributions. This sum is the LOF for TPD.

Other risk factors to transmission and distribution above 60 psig pipeline segments may be considered by the TPD Committee based upon new available information and included in the algorithm. These determinations are regularly reviewed and subject to change per RMP-01.

Following are the factors for TPD.

A) **Ground-Breaking Frequency Factor** (13% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Dig-in Concern (listed as mag-loc in GIS)	100	13
Segments that have 200 or more USA (Underground Service Alert) tickets per year	100	13
Class* 3 or 4 segments that have fewer than 200 USA tickets per year	100	13
Class* 2 segments that have fewer than 200 USA tickets per year	50	6.5
Class* 1 segments that have fewer than 200 USA tickets per year	10	1.3

*Class Locations are per 49 CFR 192.5.

B) **Third Party Damage Prevention Factor** (10% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Standby*	-100	-10
Aerial Patrol	-20	-2

*Default

C) **Depth of Cover Protection Factor** (15% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
More than 5.99'	10	1.5
More than 2.99' and up to 5.99'	40	6
More than 2' and up to 2.99'	80	12
More than 0' and up to 2'	100	15
0'	60	9
Unknown*	40	6

* Default

D) **Pipe Diameter Factor** (7% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Pipe Diameter less than12”	100	7
Pipe Diameter greater than or equal to 12”	0	0

E) **Wall Thickness Factor** (13% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Less than 0.250 inches	100	13
0.250 to 0.500 inches, inclusive	30	3.9
Greater than 0.500 inches	10	1.3

F) **Line Marking Factor** (5% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Line of Sight in both directions	10	0.5
Ineffective for identifying presence of a pipeline	60	3.0
None*	100	5

* Default

G) **Operating Stress Factor** (10% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
60% of SMYS or greater	100	10
50% of SMYS or greater, up to 60%	80	8
40% of SMYS or greater, up to 50%	50	5
30% of SMYS or greater, up to 40%	30	3
20% of SMYS or greater, up to 30%	10	1
Less than 20% of SMYS	5	0.5

H) **Third Party Damage Leak Rate Factor** (18% weighting)

Leaks include leaking and non-leaking damage within the last twenty years caused by third parties and the owner-operator and its agents.

Points are assigned as follows:

Criteria	Points	Contrib.
Segments with more than one leak within the PIC	150	27
Segments with one leak within the PIC	100	18
Pipe Segment in proximity (Leak within the route PIC and within one mile)	50	9
No Leak	0	0

PIC (Potential Impact Circle) is defined as the area within the Potential Impact Radius as defined by RMP-08

l) **Public Education Program Factor** (9% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Field Contact*	-100	-9
Landowner Notification**	-70	-6.3
Trade Show ***	-25	-2.25
Public Education not done	0	0

* Field Contact is defined as direct contact at the job site within the last 12 months.
** Letter sent to landowner within the last 24 months.
*** Pipe segments within a 30-mile radius of a trade show that was attended within the last 12 months. The Public Awareness Program Manager keeps a record of trade shows and establishes the area credited for the trade show.

PACIFIC GAS AND ELECTRIC COMPANY

GAS OPERATIONS

PUBLIC SAFETY & INTEGRITY MANAGEMENT

PG&E

Risk Management Procedure

Procedure No. RMP-04

Revision 07

Weather-Related and Outside Forces Threat Algorithm

7

Gas Transmission Integrity Management Program

for PG&E and Standard Pacific Gas Line, Inc.

Prepared By: Redacted Date: 7/12/12

Redacted Risk Engineer

Concur: Redacted Date: 7/11/12

Redacted, Risk Management Supervisor

Concur: Redacted Date: 7/13/12

Redacted Integrity Management Engineering Manager

Concur: Date: 7-16-12

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Concur: Date: 7-27-12

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Rev. No.	Date	Description	Prepared By	Approved By	Approved Director of Integrity Management and Technical Support
0	11/24/01	Initial Issue	Redacted	Redacted	Redacted
1	6/11/04	Revised as Shown			
2	10/28/05	Revised as Shown			
3	3/5/07	Revised as Shown			
4	12/27/08	Added Section 6.2-Distribution Algorithm & other minor changes			RPF2

Rev. No.	Date	Description	Prepared By	Approved By	Manager, System Integrity	Director, System Integrity
5	10/09/09	Revised as Shown	Redacted	Redacte	SEBE	RPF2

Rev No	Date	Description	Prepared by	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
6	3/26/12	Revised weighting in Risk Calculation	Redacted	SEBE	N/A	SLHB	RIT4

Rev No	Date	Description	Prepared by	Risk Management Supervisor	Integrity Management Engineering Manager	Director, Transmission Integrity Management	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
7	7/29/12	See Change Form	Redacted	Redacted		B2BY	SLHB	RIT4

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1.0 PURPOSE

The purpose of this procedure is to establish a weather-related and outside forces threat algorithm as part of the determination of Likelihood of Failure for PG&E's Gas Transmission and Distribution Integrity Management Programs, described in RMP-06 and RMP-15. 7

2.0 SCOPE

2.1 Transmission

This guideline applies to all of PG&E's gas transmission pipeline facilities and is to be used in conjunction with RMP- 01, Risk Management Procedure. The algorithm described in this procedure is used for transmission pipelines and associated appurtenances per RMP-01. The results are communicated to the Gas Transmission Integrity Management Program (TIMP), whose risk management processes are designed to meet the requirements of 49 CFR 192 Subpart O. The TIMP group performs a risk assessment to identify and prioritize risks for distribution pipelines per RMP-06.

2.2 Distribution

The algorithm described in this procedure is also used for distribution pipelines and associated appurtenances operating over 60 psig. The results are communicated to the Gas Distribution Integrity Management Program (DIMP), whose risk management processes are designed to meet the requirements of 49 CFR 192 Subpart P. The DIMP group performs a risk assessment to identify and prioritize risks for distribution pipelines per RMP-15.

3.0 INTRODUCTION

As required by RMP-01, RMP-06, and RMP-15, this procedure (RMP-04) supports the calculation of risk due to potential threats associated with weather-related and outside forces (WROF). 7

RMP-01 describes Risk as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). A relative risk assessment model is used to establish risk for all pipeline segments within the scope of RMP-01.

LOF is defined as the sum of the following threat categories:

- External corrosion (EC)
- Internal corrosion (IC)
- Stress corrosion cracking (SCC)
- Third party damage (TPD)
- Weather-related and outside forces (WROF) 7
- Manufacturing (M)

- Construction, including welding/fabrication-related risks (C)
- Equipment (E)
- Incorrect operations (IO)

Where Manufacturing and Construction are handled together, they are designated M&C.

See RMP-15 for equivalent identified distribution threats, per 49 CFR 192.1007.

For each threat category, the appropriate steering committee identifies the significant factors that influence the LOF for that threat. (For a discussion of steering committees, see RMP-01.)

4.0 ROLES AND RESPONSIBILITY

The Integrity Management Group is responsible for managing risk within the scope of this procedure. The Integrity Management Group shall establish and manage the risk of each pipeline facility using methodologies that are

- consistent with industry practice
- acceptable to regulatory agencies
- appropriate for PG&E's gas facilities
- in conformance with this procedure

Specific responsibilities for ensuring compliance with this procedure are as follows:

Title	Reports to	Responsibilities
Risk Management Supervisor	Integrity Management Risk Manager	• Supervise completion of work (schedule/quality) • Monitor compliance with procedure and take corrective actions as necessary • Analyze and communicate risk assessment results • Ensure training of assigned individuals
Risk Management Engineers	Risk Management Supervisor	• Perform calculations per procedure • Analyze and communicate risk assessment results • Identify need for changes

5.0 TRAINING AND QUALIFICATIONS

5.1 Training

Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training	How Often
Risk Management Supervisor	Procedure review of RMP-01 and RMP-05	• Upon initial assignment • Once each calendar year
WROF Steering Committee Chairman	Procedure review of RMP-01 and RMP-05	• Upon initial assignment • Once each calendar year • As changes are made to the procedure
WROF Steering Committee Members (Subject Matter Experts)	Review RMP-05 and Steering Committee requirements of RMP-01	• Once each calendar year at the time of the steering committee meeting
Risk Management Engineers	Per RMP-06 and RMP-15 requirements; review RMP-05	• Upon initial assignment • Once each calendar year • As changes are made to the procedure

5.2 Qualifications

See RMP-06 and RMP-15 for qualification requirements.

6.0 WEATHER-RELATED AND OUTSIDE FORCES THREAT ALGORITHM

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Scoring for the WROF threat algorithm shall be calculated per the direction of the Weather-Related and Outside Force (WROF) Steering Committee. The committee has determined that the factors listed as A through F of this section are significant for determining LOF due to WROF.

Before applying the algorithm, the Risk Management Engineer shall evaluate the list of factors and determine whether any factors should be added, removed or modified. Changes to factors, point values, and other aspects of the risk algorithm are performed per RMP-01 and the Management of Change (MOC) process, as discussed in RMP-06.

The LOF for WROF is calculated by:

1. Assigning points to each factor is based on maintenance and operating records, assessment results, local site features and conditions and pipeline attribute information.
2. Multiplying the assigned points by the weighting for the factor, as established by the WROF Steering Committee. This product is the ***contribution*** for the factor.
3. Summing the factor contributions. This sum is the LOF for WROF.

Other risk factors to transmission and distribution above 60 psig pipeline segments may be considered by the WROF Committee based upon new available information and included in the algorithm. These determinations are regularly reviewed and subject to change per RMP-01.

Following are the factors for WROF.

A) **Crossings Factor*** (30% weighting)
If the pipeline segment has both a major water crossing and a fault crossing, points are assigned for both criteria additively.
Points are ***additive*** and are assigned as follows:

Criteria	Points	Contrib.
Major water crossing present*	40	12
Seismic fault crossing present **	300×PR	0.3×300×PR
Neither major water crossing nor seismic fault crossing are present	0	0
Seismic fault crossing present but fully mitigated per 6.0.E of this procedure	0	0

* A major water crossing crosses a waterway identified as a Commercially Navigable Waterway by the Office of Pipeline Safety (OPS) in its National Pipeline Mapping System.
** Probabilities of rupture (PRs) due to seismic fault crossings are listed in Attachment 1. The number 300 is a non-dimensional multiplier used to weight fault crossings as set by the WROF Committee. Sample calculation: Hayward Fault, PR = 31%, Points = (300×0.31) = 93 and Contribution = (0.3×300×0.31) = 27.9.

B) **Unstable Soil Factor** (15% weighting)
Unstable ground is an area designated in GIS as having any of the following:

- Moderate to high liquefaction susceptibility
- Moderate to high landslide susceptibility
- Known landslide
- Known liquefaction

Points are assigned as follows:

Criteria	Points	Contrib.
Known landslide	120	18
Moderate to high landslide	100	15
Moderate, High, or Known Liquefaction	100	15
None	0	0

C) **Seismic Area Factor** (15% weighting)
Seismic Area Factor is applied only if the pipeline is in an area of unstable soil, as defined in 6.0(B), above.
Points are assigned as follows:

Criteria		Points	Contrib.
Seismic ground acceleration*	0.5g or greater	150	22.5
	0.2g or greater, but less than 0.49g	100	15
	less than 0.2g	0	0

* Seismic Ground Acceleration is defined as peak ground acceleration values associated with a 10% probability of exceedance in 50 years (or 475-year return period).

D) **Erosion Area Factor*** (10% weighting)
Pipeline Engineering reports areas of potential erosion data to the Geosciences Group, which is responsible for incorporation of those data into the GIS data source layer. Erosion areas also include levee crossings, which are noted in Attachment 2. Points are assigned as follows:

Criteria	Points	Contrib.
Pipe segment within 100 meters or less of identified erosion area*	100	10
Known levee crossings	100	10
Pipe segment outside of 100 meters of erosion area	0	0

* Erosion Areas are reported by the Pipeline Engineering Group

E) **Ground Movement Mitigation Factor** (5% weighting)
Pipeline Engineering reports these data to Risk Management, which documents the information in the project files.

- "Full Ground Movement Mitigation" substantially removes the potential for pipeline segment failure from ground movement.
- "Partial Ground Movement Mitigation" removes some, but not all, of the potential for pipeline segment failure from ground movement.
- "Fault-Crossing Mitigation" refers to a pipeline fault-crossing segment that has been mitigated for seismic fitness-for-service (F-F-S). See Attachment 1 for current listing of fault crossings and mitigation condition. For a segment with full mitigation, no Crossings Factor Points (see 6.0(A), above) are assigned.

"Known" means documented through geologic mapping, observed through aerial photography, or reported by personnel, as compiled by the Geosciences group.

Points are assigned as follows:

Criteria	Points	Contrib.
Full* Ground Movement Mitigation of known landslide performed	-360	-18
Partial* Ground Movement Mitigation of known landslide performed	-240	-12
Full* Ground Movement Mitigation of known erosion performed	-200	-10
Partial* Ground Movement Mitigation of known erosion performed	-140	-7
Fault-Crossing Mitigation**	-(Z×300×PR)	-(0.05×Z×300 ×PR)
No mitigation	0	0

* The degree of mitigation (full or partial) is reported by the appropriate Pipeline Engineer to the Risk Management Engineer for assignment of points under this LOF factor.
** Mitigation points are assigned in consideration of 6.0(A), Crossings Factor. 6.0(A) includes rupture potential. Probabilities of rupture (PRs) due to seismic fault crossings are listed in Attachment 1. The number 300 is a non-dimensional multiplier used to weight fault crossings, as set by the WROF Committee. The variable Z is the ratio of factor weightings between 6.0(A) and 6.0(E) (Crossing Factor Weighting/Ground Movement Mitigation Factor Weighting). Sample calculation: Hayward Fault (if crossing were mitigated), PR = 31%, Z=.3/.05=6, Points = 6×(300×0.31) = 558 and Contribution = -(0.05×6×300×0.31) = -27.9.

F) **Girth Weld Condition Factor** (20% weighting)
As a measure of the pipeline segment's ability to resist external forces, points are assigned as follows:

Criteria		Points	Contrib.
Pre-1962 girth welds within area of ground acceleration	0.5g or greater	120	24
	0.2g or greater, but less than 0.5g	80	16
All others		0	0

Attachment 1: FaultCrossings_2011.xls

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Attachment 2: Levee_crossings_2011.xls

MITIG	MAINTORG	PIPELINE	SEGMENT	MP1	MP2	Probability of Rupture (PR) %	F-F-S Review or Retrofit	FAULTCLASS	CROSS NUMBER	PLE COMMENT
0	DSAC	210A	118.1	18.97	19.47	2.00		5	1	Pipe on n/s of [redacted] betwee [redacted] and [redacted] Line feeds [redacted] and [redacted] and [redacted] refineries. May be able to isololate break and keep everything online. MINOR IMPACT
0	DNCO	177A	215.1	170.57	171.00	9.00		2	1	Parallel to Line 21B, which has not been mitigated. Supplies gas to all of Marin County, all of Mendocino County, and most of Sonoma County - significant impact
0	DNCO	126B	107.6	5.09	5.13	9.00		2	1	
0	DNCO	177A	217.5	172.15	172.62	9.00		2	1	Pipe on n/s o [redacted] between [redacted] and [redacted] Line feeds [redacted] and [redacted] and [redacted] refineries. May be able to isololate break and keep everything online. MINOR IMPACT
0	DNCO	126B	105	2.73	4.00	9.00		2	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The [redacted] area has about 40,000 customers plus the power plant. A failure of only Line
0	DNCO	126B	105	2.73	4.00	9.00		2	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The [redacted] area has about 40,000 customers plus the power plant. A failure of only Line
0	DNCO	126B	105	2.73	4.00	9.00		2	1	
0	DNCO	126B	105	2.73	4.00	9.00		2	1	L-303 is part of the Bay Area Loop system. The other BAL lines (114 & 131) parallel 303 at the [redacted] fault.
0	DNCO	126A	104.8	5.40	5.43	9.00		2	1	
0	DEBY	105B	115	10.34	11.64	31.00	1/1/1966, Job # 161804	1	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The [redacted] area has about 40,000 customers plus the power plant. A failure of only Line
0	DNCO	177A	237	182.00	183.14	9.00		2	1	L-306 orginally was installed to feed [redacted] This plant is no longer operating. The main purpose for the line is to back up Sempre's gas sysytems in the central coast. It is unknown when the power plant w
0	DNCO	177A	237	182.00	183.14	9.00		2	1	
0	DNCO	177A	237	182.00	183.14	9.00		2	1	Single feed to the town of [redacted] - 5,000 or so customers - moderate impact
0	DNCO	177A	237	182.00	183.14	9.00		2	1	Parallel to 12" Line 177A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The [redacted] area has about 40,000 customers plus the power plant. A failure of only L
0	DNCO	177A	237	182.00	183.14	9.00		2	1	Parallel to 12" Line 177A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The [redacted] area has about 40,000 customers plus the power plant. A failure of only L
0	DNCO	126A	102	3.08	4.00	9.00		2	1	
0	DNCO	126A	102	3.08	4.00	9.00		2	1	
0	DNCO	126A	102	3.08	4.00	9.00		2	1	
0	DSAC	210B	124	18.85	19.38	2.00		5	1	109 & 132 Run parallel and Zig Zag across fault. Funding for Geological study to be requested for 2010.
0	DPEN	132	178.05	37.80	38.39	21.00	No, 1992 EQE Study of the effect of the 1906 San Francisco Earthquake on L-109 & L-132 does not cover these fault crossings. 1/1/1964 ins	1	1	
0	DPEN	132	178.05	37.80	38.39	21.00	No, 1992 EQE Study of the effect of the 1906 San Francisco Earthquake on L-109 & L-132 does not cover these fault crossings. 1/1/1964 ins	1	1	Parallel to Line 21A, which has not been mitigated. Supplies gas to all of Marin County, all of Mendocino County, and most of Sonoma County - significant impact) Funds for seismic study to be requesting in 2012
0	DNCO	021E	180	117.24	117.46	13.00		1	1	
0	GTRA	114	157.9	33.61	33.77	2.00		5	1	Pipe on n/s of [redacted] between [redacted] and [redacted] Line feeds [redacted] and [redacted] and [redacted] refineries. May be able to isololate break and keep everything online. MINOR IMPACT
0	DSAC	210C	103.7	21.04	22.16	4.00		3	1	
0	DSAC	210C	103.7	21.04	22.16	4.00		3	1	
0	DSAC	210C	103.7	21.04	22.16	4.00		3	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The [redacted] area has about 40,000 customers plus the power plant. A failure of only Line
0	DSAC	210C	103.7	21.04	22.16	4.00		3	1	Pipe along [redacted] and [redacted]. from [redacted] to [redacted] Serves customers in [redacted] area, San Pablo Station, and [redacted] Refinery. Line basically parallels SP-3 from Fran
0	DNCO	126A	103.3	4.09	4.92	9.00		2	1	
0	DNCO	126A	103.3	4.09	4.92	9.00		2	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The [redacted] area has about 40,000 customers plus the power plant. A failure of only Line
0	DNCO	126A	103.3	4.09	4.92	9.00		2	1	
0	DNCO	126A	103	4.00	4.09	9.00		2	1	
0	GHOL	301G	105.3	2.34	2.75	7.00		1	1	
0	DDIA	SP3	122	179.28	179.66	4.00	Yes, 1/1/1990, Job # 4545489	3	1	

0	DCCO	181B	103.6	1.14	2.10	21.00		1	1	
0	G300N	306	115.6	26.71	38.00	21.00	Installed 1/1/1962, Job # 148721	2	1	
0	G300N	306	115.6	26.71	38.00	21.00	Installed 1/1/1962, Job # 148721	2	1	
0	DNCO	021E	203.8	137.36	137.38	13.00		2	1	
0	G300S	313	119	33.29	34.34	2.00		5	1	
0	G300S	313	119	33.29	34.34	1.00		5	1	
0	G300S	313	119	33.29	34.34	1.00		5	1	
0	DDIA	3004-01	102	0.00	0.92	4.00		3	1	Parallel to 12" Line 177A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of only L
0	DDIA	3004-01	102	0.00	0.92	4.00		3	1	
0	DSAC	210B	127.3	20.22	21.00	4.00		3	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of only Line
0	DSAC	210B	127.3	20.22	21.00	4.00		3	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of only Line
0	GHOL	103	113	9.03	10.00	21.00		1	1	Single feed to the town of Re - 5,000 or so customers - moderate impact
0	GHOL	103	113	9.03	10.00	21.00		2	1	
0	DPEN	109	181.3	36.51	36.67	21.00	No, 1992 EQE Study of the effect of the 1906 San Francisco Earthquake on L-109 & L-132 does not cover these fault crossings. 1/1/1964 ins	1	1	Parallel to 6" Line 126A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of Line 17
0	DPEN	0210-01	105	0.31	0.63	21.00		1	1	Pipe on n/s of Re between Re and Redacte Line feeds Redacted and Re and Redacte refineries. May be able to isololate break and keep everything online. MINOR IMPACT
0	GHOL	300B	397	466.00	470.41	7.00		1	1	
0	GHOL	300B	397	466.00	470.41	7.00		2	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of only Line
0	GTRA	131	135	27.05	28.00	3.00		3	1	
0	GTRA	131	135	27.05	28.00	3.00		3	1	
0	DDIA	191-1	103.1	14.23	14.71	3.00		5	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of only Line
0	G300N	306	115.1	17.82	26.19	21.00	Installed 1/1/1962, Job # 148721	1	1	To resolve this issue we may need to relocate10 miles of pipe. Refer to PSRS 15143
0	GHOL	301A	105.52	2.24	2.75	7.00	Update Job # 176359-71, Pipe installed 1/1/1951	1	1	To resolve this issue we may need to relocate10 miles of pipe. Refer to PSRS 15143
0	DSJO	0833-01	101	0.03	2.27	7.00		2	1	
0	DNCO	126B	119.11	5.98	6.31	9.00		2	1	To resolve this issue we may need to relocate10 miles of pipe. Refer to PSRS 15143
0	G300S	313	105	12.63	16.00	1.00		5	1	
0	G300S	313	118	32.00	33.29	1.00		5	1	
0	DNCO	177A	238.5	183.75	183.80	9.00		2	1	
0	DPEN	0213-02	201.3	0.00	0.48	21.00		1	1	
0	DPEN	0213-02	201.3	0.00	0.48	21.00		1	1	Parallel to 6" Line 126A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of Line 17
0	G300S	300B	205	175.17	180.10	1.00		5	1	
0	GBUR	400	138	47.17	48.64	3.00		3	1	Parallel to 12" Line 177A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of only L
0	DDIA	191-1	103.29	19.08	19.25	4.00		3	1	
0	DNCO	126A	108	6.34	7.00	9.00		2	1	
0	DNCO	126A	108	6.34	7.00	9.00		2	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of only Line
0	DNCO	126B	123	6.86	7.00	9.00		2	1	L-306 orginally was installed to feed Morro Bay Power Plant. This plant is no longer operating. The main purpose for the line is to back up Sempre's gas sysytems in the central coast. It is unknown when the power plant w
0	G300N	300A	207.2	227.67	229.63	6.00		2	1	
0	G300N	300A	207.2	227.67	229.63	6.00		1	1	Parallel to 12" Line 177A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of only L

0	G300S	300A	139.9	116.92	120.95	12.00		5	1	Parallel to 12" Line 177A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The [redacted] area has about 40,000 customers plus the power plant. A failure of only L
0	GHOL	301D	211	1.00	1.72	21.00		1	1	
0	G300S	300B	153.5	113.68	116.28	2.00		5	1	
0	GHOL	310	119	14.87	17.27	21.00		2	1	Pipe along [redacted] and [redacted] from [redacted] to [redacted] Serves customers in [redacted] area, San Pablo Station, and [redacted] Refinery. Line basically parallels SP-3 from Fran
0	DPEN	109	182	36.67	36.73	21.00	No, 1992 EQE Study of the effect of the 1906 San Francisco Earthquake on L-109 & L-132 does not cover these fault crossings. 1/1/1964 ins	1	1	Parallel to Line 21A, which has not been mitigated. Supplies gas to all of Marin County, all of Mendocino County, and most of Sonoma County - significant impact). Funds for seismic study to be requesting in 2012
0	GTRA	303	120.15	24.71	25.22	2.00		5	1	To resolve this issue we may need to relocate10 miles of pipe. Refer to PSRS 15143
0	DMIS	2408-11	113	4.99	5.18	2.00		5	1	
0	GHOL	300A	356.11	461.62	461.80	7.00		2	1	
0	G300N	300A	226.2	255.91	256.21	2.00		4	1	
0	G300N	300A	226.2	255.91	256.21	2.00		4	1	
0	DNCO	126B	106	4.00	4.60	9.00		2	1	
0	DNCO	126B	106	4.00	4.60	9.00		2	1	L-114 is part of the Bay Area Loop system. The other BAL lines (303 & 131) parallel 114 at the [redacted] fault. The 2007 replacement was a WRO project and did NOT address the fault crossing.
0	DNCO	126B	106	4.00	4.60	9.00		2	1	
0	G300S	300A	139.7	114.67	116.48	2.00		5	1	
0	G300S	300B	160	130.41	131.37	2.00	Built 1/1/1952, Update Job #7036664-02, 6/18/2001	5	1	
0	G300S	300B	160	130.41	131.37	2.00	Built 1/1/1952, Update Job #7036664-02, 6/18/2001	5	1	
0	G300N	300B	247.0	228.01	228.91	6.00		2	1	To resolve this issue we may need to relocate10 miles of pipe. Refer to PSRS 15143
0	GTRA	303	117	18.27	18.84	3.00		3	1	
0	GTRA	303	117	18.27	18.84	3.00		3	1	L-131 is part of the Bay Area Loop system. The other BAL lines (114 & 303) parallel 131 at the [redacted] fault.
0	G300S	300B	158	129.88	130.36	2.00		5	1	
0	G300S	300A	152.1	130.43	130.97	2.00	Built 1/1/1950, Update Job #7036664-02, 6/29/2001	5	1	
0	G300S	300A	152.1	130.43	130.97	2.00	Built 1/1/1950, Update Job #7036664-02, 6/29/2001	5	1	
0	G300S	313	102	4.02	7.99	2.00		5	1	
0	G300S	300B	155	116.72	121.44	12.00		5	1	
0	GHOL	300B	394	463.75	464.46	7.00		1	1	
0	G300N	300B	247.1	228.91	228.94	6.00		1	1	109 & 132 Run parallel and Zig Zag across fault. Funding for Geological study to be requested for 2010.
0	DNCO	126B	104	2.17	2.73	9.00		2	1	
0	DDIA	3004-01	100.3	2.28	2.31	4.00		3	1	
0	GBUR	400	140	48.65	64.99	3.00		3	1	L-131 is part of the Bay Area Loop system. The other BAL lines (114 & 303) parallel 131 at the [redacted] fault.
0	DKRN	311	118	31.97	38.49	6.00		2	1	Parallel to 12" Line 177A and Line 126A. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The [redacted] area has about 40,000 customers plus the power plant. A failure of only Line
0	GHOL	310	118	14.61	14.82	21.00		1	1	
0	GBUR	400	156	74.66	78.29	2.00		5	1	
0	GBUR	400	156	74.66	78.29	2.00		5	1	
0	GBUR	400	156	74.66	78.29	2.00		5	1	
0	GBUR	400	156	74.66	78.29	2.00		5	1	
0	G300S	300A	149.7	129.03	130.36	2.00		5	1	
0	G300S	300A	149.4	127.93	129.03	2.00		4	1	
0	G300S	300B	157.4	127.50	129.88	2.00		4	1	
0	DMIS	2408-11	102.5	1.25	1.89	2.00		5	1	
0	DMIS	2408-11	102.6	1.94	2.51	2.00		5	1	
0	DKRN	6603-01	109.5	0.33	3.96	1.00		5	1	
0	DKRN	6603-01	109.5	0.33	3.96	1.00		5	1	
0	DKRN	6603-01	109.5	0.33	3.96	1.00		5	1	
0	DKRN	6603-01	109.5	0.33	3.96	1.00		5	1	
0	DDIA	SP3	122.2	179.66	179.85	4.00	Yes, 1/1/1990, Job # 4545489	3	1	
0	GHOL	300B	396.5	465.41	466.00	7.00		1	1	L-303 is part of the Bay Area Loop system. The other BAL lines (114 & 131) parallel 303 at the [redacted] fault.
0	GBUR	401	158	47.34	48.12	3.00		3	1	Parallel to 12" Line 177A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The [redacted] area has about 40,000 customers plus the power plant. A failure of only L
0	G300N	300B	268.2	256.28	256.64	2.00		4	1	

0	G300S	314	141	40.29	43.14	1.00		5	1	
0	GBUR	401	180	57.99	58.69	3.00		3	1	Parallel to 12" Line 177A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Red area has about 40,000 customers plus the power plant. A failure of only L
0	DMIS	2408-11	109	4.29	4.35	2.00		5	1	
0	GBUR	401	219	77.79	78.27	2.00		5	1	
0	DKRN	372	101	0.00	3.70	1.00		5	1	
0	DKRN	311-1	118	31.97	38.51	6.00		2	1	Parallel to 12" Line 177A and 4" Line 126B. The majority of the load is covered by Line 177A, which feeds the Humboldt Bay Power Plant. The Re area has about 40,000 customers plus the power plant. A failure of only L
0	GHOL	300A	351.41	455.20	457.81	7.00		1	1	109 & 132 Run parallel and Zig Zag across fault. Funding for Geological study to be requested for 2010.
0	GTRA	114	152.2	26.93	27.67	3.00		3	1	
0	GHOL	300A	351.53	458.34	459.58	7.00		1	1	L-303 is part of the Bay Area Loop system. The other BAL lines (114 & 131) parallel 303 at the Reda fault.
0	GHOL	300A	351.44	457.95	458.13	7.00		1	1	To resolve this issue we may need to relocate10 miles of pipe. Refer to PSRS 15143
0	GHOL	300A	351.425	457.81	457.89	7.00		1	1	
0	DNCO	021A	130	27.32	29.27	21.00	Mitigated with sloped trench through the fault traces - Geosciences Department involvement 1988 - GM 4692521	2	1	
0	DNCO	126B	103	1.43	2.16	9.00		2	1	
0	GBUR	401	218	77.00	77.78	2.00		5	1	
0	GBUR	401	217	76.10	77.00	2.00		5	1	
0	GBUR	401	217	76.10	77.00	2.00		5	1	
0	GHOL	301H	115	1.69	1.75	21.00		1	1	L-114 is part of the Bay Area Loop system. The other BAL lines (303 & 131) parallel 114 at the Reda fault. The 2007 replacement was a WRO project and did NOT address the fault crossing.
0	DNCO	021B	117	15.00	16.94	21.00		2	1	Gas Transmission line 103 is a 1930 vintage 12 inch steel welded line. This line is constructed with poor quality welds and outdated, low quality main line valves. The line travels across the Redac fault line and thro
0	DNCO	021B	117	15.00	16.94	21.00		2	1	
0	GHOL	301A	108	5.00	8.00	3.00	176359-71	3	1	
0	GHOL	301A	108	5.00	8.00	3.00	176359-71	3	1	
0	GHOL	301A	108	5.00	8.00	3.00	176359-71	3	1	
0	DKRN	375A	103	1.00	2.00	2.00		4	1	
0	DNCO	125	109	0.00	0.00	9.00		2	1	
0	DNCO	125	110.8	0.00	0.00	9.00		2	1	
0	DNCO	125	103.3	0.00	0.00	9.00		2	1	
0	DNCO	125	100.6	0.00	0.00	9.00		2	1	
0	DNCO	125	104.81	0.00	0.00	9.00		2	1	
0	DDIA	DF7711	100	0.00	0.00	4.00		3	1	
0	DSAC	GCUST588	103	0.00	0.46	4.00		3	1	
1	GMIL	303	136.2	40.95	41.09	31.00	F-F-S Review 2008, Job #: 407548	1	1	
1	GMIL	303	136.2	40.95	41.09	31.00	F-F-S Review 2008, Job #: 407548	2	1	
1	DEBY	SP3	155.7	197.07	197.45	31.00	Yes, 1/1/1994, Job # 4224457	1	1	
1	DEBY	SP3	155.7	197.07	197.45	31.00	Yes, 1/1/1994, Job # 4224457	1	1	
1	DEBY	SP3	155.7	197.07	197.45	31.00	Yes, 1/1/1994, Job # 4224457	2	1	
1	GMIL	131	167.21	48.72	48.74	31.00	Yes, 9/7/2004, Job # 7045165	1	1	
1	GMIL	107	157.2	29.65	29.81	31.00	F-F-S Review 2008, Job #: 407548	1	1	
1	GMIL	107	157.2	29.65	29.81	31.00	F-F-S Review 2008, Job #: 407548	2	1	
1	DSAC	210A	122.4	20.24	20.80	4.00	Yes, 1/13/2004, Job # 7033657	3	1	
1	DSAC	210A	122.4	20.24	20.80	4.00	Yes, 1/13/2004, Job # 7033657	3	1	
1	GTRA	131	157.4	42.38	42.42	7.00	Yes, 2/12/03, Job # 7036856	2	1	
1	GHOL	301A	110.6	11.27	11.39	21.00	Yes, 2001 Uprate Job #: 7029905-01, Pipe Installed 1/1/1967,	1	1	
1	GTRA	303	128.6	34.65	34.40	7.00	Yes, 10/19/2006, Job # 7047685	2	1	
1	GTRA	107	141.3	22.30	22.34	7.00	Yes, 11/24/2003, Job # 7045166	2	1	
1	GHOL	301G	111.3	11.05	11.23	21.00	Yes, 6/16/2001 Job #: 7029905-01	1	1	

Route	Segment	MP1	MP2	Type	Date_ Insta	PGA	Diameter	Location	Latitude	Longitude
114	106	3.18	3.80	Backbone	1942	0.35	12.750	Redacted	Redacted	Redacted
114-2	101	3.18	3.80	Backbone	1942	0.35	12.750			
400-3	101.1	295.91	296.40	Backbone	1961	0.35	26.000			
195-1	101	0.00	1.24	Local Trans	1954	0.30	16.000			
168-1-3	104	0.28	0.32	Gathering	1961	0.30	8.625			
168-1-3	103	0.12	0.28	Gathering	1961	0.30	12.750			
401	568	293.47	294.21	Backbone	1992	0.35	42.000			
400	471	293.86	294.34	Backbone	1961	0.35	26.000			
400	471.1	294.34	296.18	Backbone	1961	0.35	26.000			
400-3	101.2	296.40	298.28	Backbone	1961	0.35	26.000			
400-3	103	298.32	299.44	Backbone	1961	0.35	26.000			
196A	112.9	8.48	8.56	Local Trans	1941	0.30	16.000			
196A-1	401	8.48	8.56	Local Trans	1941	0.30	8.630			
196A	120	11.53	11.58	Local Trans	1941	0.30	16.000			
131	115	7.39	7.75	Backbone	1946	0.35	12.750			
316A	113	1.00	1.09	Gathering	1965	0.30	4.500			
401	574.1	297.82	298.04	Backbone	1992	0.35	42.000			
316A	114	1.10	1.19	Gathering	1965	0.30	4.500			
131Y	105	0.69	0.70	Local Trans	1989	0.30	12.750			
131Z	105	0.68	0.68	Local Trans	1989	0.30	10.750			
400	473	296.22	297.38	Backbone	1961	0.35	26.000			
401	574	297.38	297.82	Backbone	1992	0.35	42.000			
316	102	0.30	0.43	Local Trans	1965	0.30	8.630			
057B	102.3	2.01	2.03	Storage	1974	0.25	22.000			
057B	102.6	2.03	2.05	Storage	1974	0.25	22.000			
196A	112.8	8.47	8.48	Local Trans	1941	0.30	16.000			
057A-MD1	103.1	0.66	0.91	Storage	1961	0.25	10.750	Line closest to Turner Cut Station		

316	103	0.43	1.90	Local Trans	1965	0.30	10.750	Redacted	Redacted	Redacted
401	577	300.83	301.39	Backbone	1992	0.30	42.000			
057B	105	3.27	3.52	Storage	1974	0.25	22.000			
196A	109.5	6.65	6.85	Local Trans	2004	0.30	8.625			
197B	107	4.52	4.71	Local Trans	1941	0.30	12.750			
197A	105.3	3.93	4.00	Local Trans	1957	0.30	10.750			

PACIFIC GAS AND ELECTRIC COMPANY

GAS OPERATIONS

PUBLIC SAFETY & INTEGRITY MANAGEMENT

PG&E

Risk Management Procedure

Procedure No. RMP-05
Revision 7
Manufacturing and Construction Threat Algorithm 7

Gas Integrity Management Program
for PG&E and Standard Pacific Gas Line, Inc.

Prepared By: Redacted Date: 7/11/2012
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Concur: Redacted Date: 7/10/2012
Redacted Risk Management Supervisor

Concur: Redacted Date: 7/13/2012
Redacted Integrity Management Engineering Manager

Concur: Date: 7-10-12
Bennie Barnes, Director, Transmission Integrity Management

Concur: Date: 7-27-12
Sanford Hartman, Vice President, Managing Director, Law

Approved By: Date: 7/29/2012
Roland Trevino, Vice President, Public Safety & Integrity Mgmt

Rev. No.	Date	Description	Prepared By	Approved By	Approved Director of Integrity Management and Technical Support
0	11/13/01	Initial Issue	Redacted	Redact ed	SEE ABOVE
1	11/25/03	Revised as Shown			Redact ed
2	9/28/05	Revised as Shown			
3	10/28/05	Revised as Shown			
4	12/28/09	Revised as Shown		SEBE	RPF
5	12/28/10	Revised as Shown		Redacte	SEBE

Rev No	Date	Description	Prepared by	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
6	3/26/12	Revised weighting in Risk Calculation	Redacted	SEBE	N/A	SLHB	RIT4

Rev No	Date	Description	Prepared by	Risk Management Supervisor	Integrity Management Engineering Manager	Director, Transmission Integrity Management	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
7	7/29/12	Revised as Shown	Reda	Redact ed	Redact	B2BY	SLHB	RIT4

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1.0 PURPOSE

The purpose of this procedure is to establish the manufacturing and construction threat algorithm as part of the determination of Likelihood of Failure for PG&E's Gas Transmission and Distribution Integrity Management Program, described in RMP-06 and RMP-15. 7

The manufacturing and construction threat algorithm set forth in this document also considers welding and fabrication related threats as described in ASME B31.8S.

2.0 SCOPE

2.1 Transmission

This guideline applies to all of PG&E's gas transmission pipeline facilities and is to be used in conjunction with RMP-01, Risk Management Procedure. The algorithms described in this procedure are used for transmission pipelines and associated appurtenances, per RMP-01. The results are communicated to the Gas Transmission Integrity Management Program (TIMP), whose risk management processes are designed to meet the requirements of 49 CFR 192 Subpart O. The TIMP group performs a risk assessment to identify and prioritize risks for transmission pipelines per RMP-06.

2.2 Distribution

The algorithm described in this procedure is also used for distribution pipelines and associated appurtenances operating over 60 psig. The results are communicated to the Gas Distribution Integrity Management Program (DIMP), whose risk management processes are designed to meet the requirements of 49 CFR 192 Subpart P. The DIMP group performs a risk assessment to identify and prioritize risks for distribution pipelines per RMP-15.

3.0 INTRODUCTION

As required by RMP-01, RMP-06, and RMP-15, this procedure (RMP-05) supports the calculation of risk due to potential manufacturing and construction threats.

RMP-01 describes Risk as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). A relative risk assessment model is used to establish risk for all pipeline segments within the scope of RMP-01.

LOF is defined as the sum of the following threat categories:

- External corrosion (EC)
- Internal corrosion (IC)
- Stress corrosion cracking (SCC)
- Third party damage (TPD) 7
- Weather-related and outside forces (WROF)

- Manufacturing (M)
- Construction, including welding/fabrication-related risks (C)
- Equipment (E)
- Incorrect operations (IO)

  Where Manufacturing and Construction are handled together, they are abbreviated M&C.

  See RMP-15 for equivalent identified distribution threats, per 49 CFR 192.1007.

For each threat category, the appropriate steering committee identifies the significant factors that influence the LOF for that threat. (For a discussion of steering committees, see RMP-01.)

4.0 ROLES AND RESPONSIBILITY

The Integrity Management Group is responsible for managing risk within the scope of this procedure. The Integrity Management Group shall establish and manage the risk of each pipeline facility using methodologies that are

- consistent with industry practice
- acceptable to regulatory agencies
- appropriate for PG&E's gas facilities
- in conformance with this procedure

Specific responsibilities for ensuring compliance with this procedure are as follows:

Title	Reports to	Responsibilities
Risk Management Supervisor	Integrity Management Engineering Manager (IMEM)	• Supervise completion of work (schedule/quality) • Monitor compliance with procedure and take corrective actions as necessary • Analyze and communicate risk assessment results • Ensure training of assigned individuals
Risk Management Engineers	Risk Management Supervisor	• Perform calculations per procedure • Analyze and communicate risk assessment results • Identify need for changes

5.0 TRAINING AND QUALIFICATIONS

5.1 Training

Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training	How Often
Risk Management Supervisor	Procedure review of RMP-01 and RMP-05	• Upon initial assignment • Once each calendar year
M&C Steering Committee Chairman	Procedure review of RMP-01 and RMP-05	• Upon initial assignment • Once each calendar year • As changes are made to the procedure
M&C Steering Committee Members (Subject Matter Experts)	Review RMP-05 and Steering Committee requirements of RMP-01	• Once each calendar year at the time of the steering committee meeting
Risk Management Engineers	Per RMP-06 and RMP-15 requirements; review RMP-05	• Upon initial assignment • Once each calendar year • As changes are made to the procedure

5.2 Qualifications

See RMP-06 and RMP-15 for qualification requirements.

6.0 MANUFACTURING AND CONSTRUCTION THREAT ALGORITHM

Scoring for the M&C threat algorithm shall be calculated per the direction of the M&C Steering Committee. The Committee has determined that the factors listed as A through G of this section are significant for determining LOF due to manufacturing and construction issues.

Before applying the algorithm, the Risk Management Engineer shall evaluate the list of factors and determine whether any factors should be added, removed or modified. Changes to factors, point values, and other aspects of the risk algorithm are performed per RMP-01 and the Management of Change (MOC) process prescribed in RMP-06.

The Risk Management Engineer assigns points to each pipeline segment in accordance with the factor tables below. Points are assigned using all available data including manufacturing and construction records and results of inspections and testing.

The LOF for M&C is calculated by:

1. Assigning points to each factor based on maintenance and operating records, assessment results, local site features and conditions, and pipeline attribute information.
2. Multiplying the assigned points by the weighting for the factor, as established by the M&C Steering Committee. This product is the contribution for the factor.
3. Summing the factor contributions. This sum is the LOF for M&C.

Other risk factors to transmission and distribution above 60 psig pipeline segments may be considered by the M&C Committee based upon new available information and included in the algorithm. These determinations are regularly reviewed and subject to change per RMP-01.

Following are the factors for M&C. If the total points assigned are negative, then default to zero for total score.

A) **Pipe Seam Design Factor** (30% weighting)
Welds made prior to 1970 using the ERW welding process are assumed to be made using low frequency unless otherwise noted.
In the table, JE is Joint Efficiency.
Points are assigned as follows:

Criteria		Points	Contrib.
Furnace Butt Weld (FBW) (JE = 0.6)		100	30
Single Submerged Arc Weld SSAW (JE = 0.8)		60	18
Low Freq. ERW (JE = 1.0)		90	27
A.O. Smith or Flash Weld (JE =0.8)		90	27
Lap Weld (JE=0.8)		90	27
High Freq. ERW (JE = 1.0)		20	6
Double Submerged Arc Weld (DSAW) (JE = 1.0)	Pre-1962	20	6
	1962 and newer	10	3
Seamless		10	3
Spiral, pre-1990 (JE = 0.8)		90	27
Spiral, 1990 and newer (JE=1.)		20	6
Other		100	30
Unknown Weld type made prior to 1970*		100	30
Unknown Weld type made in 1970 or later		20	6

* Default

B) **Girth Weld Factor** (15% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Pre-1930 girth welds (both arc and oxyacetylene, regardless of seismic zone)**	100	15
Pre-1947 girth welds within area of ground acceleration $\geq$ 0.2g	100	15
Shielded pre-1960 Bell-Spigot/BBCR*	40	6

* Shielded Metal Arc Welds (SMAW) made prior to 1960, or girth weld joints made with Bell-Spigot or Bell-Bell Chill Ring (BBCR) joints.
** Default

C) **Material Flaws or Unique Joints Factor** (20% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Wrinkle Bends in Pipe w/ OD < 12”	100	20
Wrinkle Bends in Pipe w/ OD > 12”	50	10
Dresser Couplings or Expansion Joints	100	20
Hard Spots *	100	20
Pre-1962 miter bends	90	18
None	0	0

* Hard Spots points shall be assigned based on manufacturer and age, per RMP-16.

D) **Pipe Age Factor** (10% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
Pre-1970 pipe*	100	10
1970 and newer pipe	10	1

* Default

E) **Operating Stress Factor** (20% weighting)
Points are assigned as follows:

Criteria	Points	Contrib.
60% of SMYS or greater	100	20
50% of SMYS or greater, up to 60%	80	16
40% of SMYS or greater, up to 50%	50	10
30% of SMYS or greater, up to 40%	30	6
20% of SMYS or greater, up to 30%	10	2
Less than 20% SMYS	5	1

F) **Manufacturing and Construction Leak Rate Factor** (5% weighting)
Pipe segments are judged according to installation job and properties. See footnotes for this table.
Points are assigned as follows:

Criteria	Points	Contrib.
More than 1 leak[2,3]	200	10
1 leak[1,3]	160	8
No leaks	0	0

[1]Any leak on a pipe segment shall be assigned 160 points. In addition, any pipe on the same installation job number with similar pipe properties shall also be assigned 160 points.
[2]If more than one leak occurs on the same job number with similar segments, all pipes from that job shall be assigned 200 points.
[3]If a leak occurs on a segment with no job number, all similar pipe within 20 miles shall be assigned the same point weightings.

G) **Test Pressure (TP) vs. Pipe Strength* Factor** (20% weighting)
Pressure tests performed earlier than 1950 are not credited.
Points are assigned as follows:

<table>
<tr><th colspan="2">Criteria</th><th>Points</th><th>Contrib.</th></tr>
<tr><td rowspan="2">TP is equal to or greater than 90% PS and…</td><td>Test is less than or equal to 5 years old</td><td>-200</td><td>-40</td></tr>
<tr><td>Test is more than 5 years old</td><td>-150</td><td>-30</td></tr>
<tr><td colspan="2">TP is 80% or greater, but less than 90% PS</td><td>-100</td><td>-20</td></tr>
<tr><td colspan="2">TP is less than 80% PS</td><td>-50</td><td>-10</td></tr>
<tr><td colspan="2">No pressure test,
or TP/MOP is less than 1.1**</td><td>150</td><td>30</td></tr>
</table>

* Pipe Strength (PS) is equal to (SMYS)(2)(t)(Joint Efficiency)/(OD).
** Default

PACIFIC GAS AND ELECTRIC COMPANY

GAS OPERATIONS

PUBLIC SAFETY & INTEGRITY MANAGEMENT

RISK MANAGEMENT PROCEDURE

Procedure No. RMP-16
Revision 0
Threat Identification

Gas Transmission Integrity Management Program
for PG&E and Standard Pacific Gas Line, Inc.

Prepared By: Redacted Date: 8/14/2012
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Concur: Redacted Date: 8/10/12
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Roland Trevino, Vice President, Public Safety & Integrity Management

Threat Identification

Revision 0

Pacific Gas and Electric

Standard Pacific Gas Line, Inc.

			Prepared by	Approved by	Approved by	Approved by	Approved by
Rev. No.	Date	Description	Risk Management Supervisor	Integrity Management Engineering Manager	Director, Transmission Integrity Management	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
0	8/14/12	Initial Issue	Redacted	Redacted	B2BY	SLHB	RIT4

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1.0 PURPOSE

The purpose of this procedure is to provide the requirements for determining identified threats to covered segments. This procedure is written to meet the requirements of 49 CFR 192 Subpart O. It provides instructions, guidance, and requirements that align with ASME B31.8S-2004.

2.0 SCOPE

The procedure is applicable to all covered segments.

3.0 INTRODUCTION

This procedure describes a threat identification process that includes reviewing data to determine which of the nine (9) threat categories (representing 22 causes) identified by ASME B31.8S are applicable to each covered segment. The process includes data collection, data integration and threat identification. Interacting threats such as cyclic fatigue are also addressed as part of the process. The procedure described in RMP-06 is then applied to identified threats for each covered segment in order to determine the necessary integrity assessments and preventive and mitigative (P&M) measures.

The nine (9) threat categories identified by ASME B31.8S are:

1. External corrosion (EC)
2. Internal corrosion (IC)
3. Stress corrosion cracking (SCC)
4. Manufacturing related defects (M)
5. Construction, including welding/fabrication-related (C)
6. Equipment failure (E)
7. Third party damage (TPD)
8. Incorrect operations (IO)
9. Weather-related and outside force (WROF)

   Where Manufacturing and Construction are handled together, they are designated as M&C

4.0 ROLES AND RESPONSIBILITIES

Specific responsibilities for ensuring compliance with this procedure are as listed in the following table.

TABLE 1. ROLES AND RESPONSIBILITIES

Title	Reports to	Responsibilities
Integrity Management Risk Manager (IMRM)	Director of Transmission Integrity Management	- Assure this procedure is implemented effectively - Approve documents, plans and exceptions
Risk Management Supervisor (RMS)	IMRM	- Supervise Risk Management Group - Approve identified threats for each HCA
Risk Management Engineer (RME)	RMS	- Perform threat identification per procedure
Subject Matter Expert (SME)	RMS	- Provide expertise in specific area of operation or engineering - Be a 3rd party contractor that may fill any or all or the roles listed above

5.0 TRAINING AND QUALIFICATIONS

Specific training and qualifications to ensure compliance with this procedure are described in RMP-06.

6.0 PROCESS

The process of threat identification consists of the following steps:

1. Data Collection
2. Data Review
3. Data Integration
4. Threat Identification

6.1 Data Collection

Comprehensive pipeline and facility knowledge are essential to understanding the threats that can affect a covered segment. No single source of information is sufficient to determine the threats that affect a covered segment; therefore, information is gathered from numerous sources. Data for both covered and non-covered segments shall be considered during the threat identification process. At a minimum, the following shall be considered for both covered and non-covered segments:

- Past incident history
- Corrosion control records
- Continuing surveillance records
- Patrolling records
- Maintenance history
- Internal inspection records
- All other conditions specific to each pipeline

Data identified per Table 2 and Table 3 shall be collected as part of the threat identification process. Table 2 contains general data elements. Table 3 identifies the data elements as they pertain to various threats.

Where the Company, as a default, assumes a threat is present for all covered segments, data related to that particular threat may not be collected for the purposes of threat identification.

TABLE 2. DATA ELEMENTS FOR PRESCRIPTIVE PIPELINE INTEGRITY PROGRAM
ASME B31.8S, Table 1

Category	Data
Attribute data	Pipe wall thickness
	Diameter
	Seam type and joint factor
	Manufacturer
	Manufacturing date
	Material properties
	Equipment properties
Construction	Year of installation
	Bending method
	Joining method, process and inspection results
	Depth of cover
	Crossings/casings
	Pressure test
	Field coatings method
	Soil, backfill
	Inspection reports
	Cathodic protection used
	Coating type
Operational	Gas quality
	Flow rate
	Normal maximum and minimum operating pressures
	Leak/failure history
	Coating condition
	CP system performance
	Pipe wall temperature
	Pipe inspection reports
	OD/ID corrosion monitoring
	Pressure fluctuations
	Regulator/relief performance
	Encroachments
	Repairs
	Vandalism
	External forces
Inspection	Pressure tests
	In-line inspections
	Geometry inspection tools
	Bell hole inspections
	CP inspections (CIS)
	Coating condition inspections (DCVG)
	Audits and reviews

TABLE 3. DATA ELEMENTS BY THREAT
Per ASME B31.8S, Appendix A

Category	Data	Applicable Threats
Attributes	Diameter	EC, IC
	Wall thickness	EC, IC
	Pipe material	M&C
	Manufacturing process	M
	Seam type	M
	Joint factor	M
Construction	Year of installation	EC, IC, SCC, M
	Year of installation of failed equipment	E
	Coating type	EC, SCC
	Distance to compressor station	SCC
	Soil characteristics/ properties	EC
	Depth of Cover	C
	Welding procedures	C
	Post-construction girth weld reinforcement	C
	Wrinkle bend identification (including bend radii and degree of angle change)	C
	Coupling identification	C
	Post-construction coupling reinforcement	C
	NDT information on welds	C
	Seal/packing information	E
Operations	Operating stress level	EC, IC, SCC
	Operating pressure history	IC, M&C
	Operating flow rate	IC
	Operating temperature	IC, SCC, C
	Leak history	EC, IC, TPD
	Potential for outside forces	C
	Regulator or relief set point drift	E
	Vandalism incidents	TPD
	Incidents involving previous damage	TPD
	Failures caused by incorrect operations	IO
	Number of incorrect operation events	IO
	Regulator valve, relief valve, flange gasket, and O-ring failure information	E
Monitoring	One call records	TPD
	Encroachment records	TPD
	Years w/adequate CP	EC
	Years w/questionable CP	EC
	Years w/o CP	EC
	Corrosion detection devices	IC
	Gas, liquid or solid analysis	IC
Inspection	Pipe inspection reports	EC, IC, C, TPD
	Past hydrostatic pressure test information	EC, IC, SCC, C
	Coating condition	EC, SCC
	ILI for dents and gouges	TPD
	MIC detected	EC
	Procedure review information	IO
	Audit information	IO

6.2 Data Sources

Data used in threat identification process shall be collected from both internal sources and external sources. Internal sources include design, inspection and construction documentation, and current operational and maintenance records. External sources include the USGS and first responder input. The internal and external data sources used by the Company include:

- Process and instrumentation drawings (P&ID)
- Pipeline alignment drawings
- Original construction inspector notes/records
- Pipeline aerial photography
- Facility drawings/maps
- As-built drawings
- Material certifications
- Survey reports/drawings
- Safety related condition reports
- Operator standards/ specifications
- Industry standards/ specifications
- O&M procedures
- Emergency response plans
- Inspection records
- Test reports/records
- Incident reports
- Compliance records
- Design/engineering report
- Technical evaluations
- Manufacturer equipment data
- First responder input
- Existing Management Information System (MIS) databases
- Geographical Information System (GIS) databases
- Results of prior threat assessments
- Subject Matter Experts (SMEs)
- Inspection, examination, and evaluation data from integrity management implementation
- Operating history
- SCADA records
- Current mitigation activities
- Process and procedure reviews
- Maintenance records
- Patrol reports
- GIS A Forms and H Forms
- Gas Transmission Incident Reports
- Jurisdictional agency reports and databases including: ground acceleration, fault crossing, slope stability, liquefaction potential, hydrology, levee crossings, and soil resistivity
- Performance metrics, including pipeline inspections and assessments, immediate and scheduled repairs, and leaks, failures and incidents.

6.3 Data Review

Collected data shall be reviewed to determine if there are sufficient data to evaluate for the presence of each threat. Where insufficient data have been collected, the Company shall determine where additional data can be collected. Depending on the importance of the data, additional inspection actions for field data collection efforts may be used. If additional data are not available and/or cannot be obtained, then conservative assumptions shall be used in the threat identification decision trees.

The quality and consistency of the data shall be verified as a part of the data review process. Consistency of data includes the usage of common units and/or a common reference system. The age of data shall be considered, especially for time-dependent threats. Where data sets are conflicting, the Company shall investigate to determine which data set is accurate.

6.4 Data Integration

The data elements gathered from the various sources shall be aggregated and integrated. The Company shall use a common reference system of route number and mile point to allow data elements from various sources to be combined and accurately associated with common pipeline locations.

Data from GIS and other sources are then combined to evaluate each covered segment.

6.5 Threat Identification

Threat identification is performed for the nine threat categories that are identified in Table 4. The Company has developed a threat identification processes for each threat, detailed in Section 7.

TABLE 4. ASME B31.8S THREAT CATEGORIES

Time-Dependent	1	External Corrosion	Corrosion occurring on the external surface of the pipeline
	2	Internal Corrosion	Corrosion occurring on the internal surface of the pipeline
	3	Stress Corrosion Cracking	Cracking of a material produced by the combined action of corrosion and tensile stress (residual or applied)
Stable	4	Manufacturing	Defects to the pipe body and/or longitudinal seam resulting from the manufacturing process, including hard spots.
	5	Construction	Welding and fabrication defects, including wrinkle bends, buckles, stripped threads, and mechanical couplings
	6	Equipment Failure	Damage or failure of equipment associated with the pipeline
Time-Independent (includes Human Error)	7	Third Party Damage	Third party inflicted damage that results in immediate failure, vandalism, and previously damaged pipe (Also includes damages by 1^{st} and 2^{nd} parties)
	8	Incorrect Operations	Damage that occurs as a result of incorrect operation of the pipeline or associated equipment
	9	Weather-Related and Outside Force	Damage occurring as a result of weather-related or outside force (e.g., ground movement, floods, etc.)
Unknown		Unknown	Damage resulting from unknown causes

7.0 THREAT IDENTIFICATION

Threat identification determines whether each of the nine threat categories identified per ASME B31.8S are present on each covered segment. The Risk Management Engineers shall use the data collected as described in Sections 6.1 through 6.4 and the process identified in the appendices of this document to determine the presence of active threats.

7.1 External Corrosion (EC)

Appendix A-1 contains the threat identification process for EC. The threat of external corrosion is assumed to exist for all covered segments.

7.2 Internal Corrosion (IC)

Appendix A-2 contains the threat identification process for IC. The following assumptions shall be applied when using the IC threat identification process:

- Leaks or ruptures refer to any internal corrosion related failures that have occurred since installation.
- SME judgment and system knowledge will be used to determine the extent of IC influence and corrosive gas sources.
- Data related to the presence of liquids or corrosive environments greater than 2 years old shall be considered historical. Inspection data less than or equal to two years old shall be considered current.

7.3 Stress Corrosion Cracking (SCC)

Two processes are used to identify SCC on a covered segment. The processes are described in Appendix A-3 for high-pH SCC and Appendix A-4 for near-neutral-pH SCC.

When using the SCC threat identification process, the following assumptions shall be applied:

- Fusion-bonded epoxy, two-part epoxies or equivalent performing coatings are not susceptible to SCC.
- If an inspection report identifies SCC but does not distinguish the type, then both forms of cracking should be assumed to exist.

These threat identification processes are supplemented by data gathering at all integrity management excavations. NDE inspections evaluate the presence of SCC regardless of the threat identification result. This information is used to validate that the threat identification assumptions are appropriate and confirms that the presence or non-presence of SCC is consistent with the threat determination process.

If the presence of SCC occurs at locations outside of the criteria identified in the threat identification processes, then PG&E shall adjust the criteria to reflect the operating history and conditions at the location where SCC occurred.

7.4 Manufacturing Threat (M)

Two processes are used to identify the potential for manufacturing threats on a covered segment. The processes are described in Appendix A-5 for Manufacturing Defect (Seam) Threat and Appendix A-6 for Manufacturing Defect (Body of Pipe) Threat.

Company considers pipe with a joint factor of less than 1.0, low frequency welded ERW pipe or flash welded pipe per ASME B31.8S Appendices A4.4 as manufacturing seam defects. These types of pipes are considered under the manufacturing defect (seam) threat and adheres to the provisions of 49 CFR 192.917(e)(4).

Covered segments that have a potential manufacturing threat per Appendix A-5 or A-6 shall be further evaluated for stability per Section 7.4.1. Where a manufacturing defect (seam) threat is identified to be unstable, a seam assessment is required. Where a manufacturing defect (body of pipe) threat is identified, the threat shall be managed through P&M measures described in RMP-06 and RMP-17.

Stability of the manufacturing threat shall be monitored on an ongoing basis. The manufacturing and construction threat on the covered segment shall be re-evaluated per Section 7.4.1 whenever the following conditions occur:

- Operating pressure increases over the maximum operating pressure experienced during the five years preceding HCA identification per FAQ 231.
- MAOP increases
- The stresses leading to cyclic fatigue increase
- Previous manufacturing and construction leaks and incidents on the covered segment or similar non-covered segments

7.4.1 Stability of Potential Manufacturing Defects

Per 49 CFR 192.917(e)(3):

> *"An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment."*

FAQ 219 provides further guidance that:

> *"Any manufacturing or construction defect that survive the Subpart J pressure test are considered to be stable and not subject to failure, unless other threats adversely affect the stability of the residual manufacturing and construction defects. An operator is expected to conduct its threat identification analysis in sufficient detail to identify if other interacting threats could adversely affect the stability of residual manufacturing and construction defects, as required by ASME B31.8S, Section 2.2, and establish its assessment plans accordingly."*

Consequently, PG&E has established additional threat identification analysis to determine the stability of potential manufacturing and construction defects on its covered segments. This process, called an Engineering Critical Analysis (ECA), is outlined in Appendix B. It considers:

- Pipe diameter
- Pipe wall thickness
- API 5L Grade or other grade specification
- Year of pipe manufacture
- Pipe seam type
- Test pressure (Subpart J Test, commissioning Hydrotest or gas test)
- MAOP
- 5-Year MOP (maximum operating pressure experienced during the 5 years preceding identification of HCA)
- Operating pressure history
- Pressure excursions above the 5-Year MOP

- Planned MAOP changes
- Interactive threats such as fatigue

Per RMP-06, covered pipeline segments that have been found to have an unstable manufacturing seam threat shall be prioritized as high risk segments per 192.917(e)(3)(4). The baseline assessment or subsequent reassessment shall be scheduled depending on the overall risk ranking and be scheduled not to exceed three years of when the Company determined that the defect is unstable.

The integrity assessment shall be performed using an assessment technology with a proven application capable of assessing seam integrity and seam corrosion anomalies.

7.5 Construction Threat (C)

Per ASME B31.8S, Appendix A Section A5.3:

> *"The existence of construction related threats alone does not pose an integrity issue. The presence of threats in conjunction with the potential for outside force significantly increases the likelihood of an event. The data must be integrated and evaluated to determine where these construction characteristics coexist with external or outside force potential."*

Consequently, the threat identification process in Appendix A-7 has been developed to determine where potential construction threats may be subjected to outside forces for the threat to present.

For the purposes of evaluating each covered segment, significant ground movement is defined as any of the following:

- A fault crossing and a seismic event (magnitude >6.0) coupled with ground faulting
- A seismic event with ground acceleration ≥ 0.5 g
- Levee crossings in the delta list from the enterprise risk management (ERM) study that are susceptible to failure with ground acceleration ≥ 0.2g
- Known liquefaction area and a seismic event with ground acceleration ≥ 0.2g
- Known slope instability area and a seismic event with ground acceleration ≥ 0.2g
- Known landslides or washouts that are activated by intense or long duration rainfall (monitoring as part of RMI-04A)
- Pipe exposed due to excavation

Where these conditions co-exist per the process described in Appendix A-7 the covered segment shall be considered to have a construction threat and be addressed through P&M measures.

Stability of the construction threat shall be monitored on an ongoing basis for changes in the following conditions. If changes occur, the stability shall be evaluated per Section 7.5.1 whenever the following conditions occur:

- Operating pressure increases over the maximum operating pressure experienced during the five years preceding HCA identification per FAQ 231.

- MAOP increases
- The stresses leading to cyclic fatigue increase
- Previous manufacturing and construction leaks and incidents on the covered segment or similar non-covered segments

7.5.1 Stability of Potential Construction Defects

PG&E has established a threat identification analysis to determine the stability of potential manufacturing and construction defects on its covered segments. This process, called an Engineering Critical Analysis (ECA), is outlined in Appendix B.

Per RMP-06, covered pipeline segments that have been found to have an unstable construction threat shall be prioritized as a high risk segment per 192.917(e)(3)(4). The baseline assessment or subsequent reassessment shall be scheduled depending on the overall risk ranking and be scheduled not to exceed three years of when the Company determined that the defect is unstable. The integrity assessment shall be performed using an assessment technology with a proven application capable of assessing potential construction defects.

7.6 Equipment Failure Threat (E)

Appendix A-8 contains the threat identification process for the threat of E. Equipment is defined in this context as pipeline facilities other than pipe and pipe components. The threat of equipment failure is assumed to exist for all covered segments; however, the level of threat is assigned through implementation of the threat identification process. The following guidance notes are to be used when using the equipment failure threat identification process:

- An equipment failure is defined as any leak or unplanned stoppage of operation attributed to equipment.
- A "leak" is defined as an unintentional escape of gas from the pipeline. A non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak. (Per PHMSA F7100.1-1 Rev.01/11)
- Possible locations of equipment failures per ASME B31.8S – 2004 include pressure control and relief equipment, gaskets, O-rings, and seal/pump packing. Additional locations of equipment failures are possible.
- Manufacturers of valves, gaskets, and seals that have experienced failure(s) or not met design life of the equipment should receive more frequent inspection across Company's system.
- Set point drift traditionally occurs from thermal expansion of the valve due to a difference in temperature at calibration and operation.
- The threat of E is addressed through the PG&E's maintenance and operations procedures including:
  - Documenting and tracking material problem and failure reports through PG&E's Material Problem Report (MPR) system and
  - Documenting key system events in the Gas Event Reporting Tool

Where a high or medium threat level is assigned during the threat identification process, the Company shall perform additional preventative and mitigative (P&M) measures. Additional

P&M measures where a high threat level has been assigned include performing a root cause analysis (RCA) if a rupture or fire (related to equipment failure) has occurred in the last five years and planning inspections for equipment that has not been inspected or has not been inspected in more than five years. Where a medium threat level is assigned, the Company shall monitor and look for trends in the data related to equipment failure. Where a low threat level is assigned, the Company shall maintain equipment-related procedures.

7.7 Third Party Damage Threat (TPD)

Appendix A-9 contains the threat identification process for TPD. The threat of TPD is assumed to exist for all covered segments.

7.8 Incorrect Operations Threat (IO)

Appendix A-10 contains the threat identification process for the threat of IO. IO is defined as any activity, or omission of an activity, by company personnel that could directly or indirectly adversely affect the operation and integrity of the pipeline. The threat of IO is assumed to exist for all covered segments; the threat level of an IO event is assigned through implementation of the threat identification process. Where a high or medium threat level is assigned during the threat identification process, the Company shall perform additional P&M measures. Additional P&M measures where a high threat level has been assigned include:

- If maintenance is not performed according to operations and maintenance (O&M) procedures, develop and implement a performance management plan.
- If O&M procedures are not correct and up to date, update and revise procedures.
- If maintenance is not performed by qualified staff, develop a program to train and reassess staff.
- Perform an RCA if a rupture has been attributed to incorrect operations within the last five years.

Where a medium threat level is assigned, the Company shall monitor and look for trends in the data related to incorrect operations events. Where a low threat level is assigned the Company shall maintain incorrect operations procedures.

7.9 Weather-Related and Outside Force Damage Threat (WROF)

Appendix A-11 contains the threat identification process for the threat of weather-related and outside forces. Each path of the threat identification process shall be followed.

8.0 INTERACTING THREATS

49 CFR Part 192 requires operators of natural gas pipelines in high consequence areas (HCAs) to identify and evaluate all potential threats to each covered segment. Potential threats include the 9 threat categories listed in ASME-B31.8S-2004. In addition to these individual threats, operators must also consider the potential for threats to interact to create potentially more severe conditions than would be indicated by only one of the threats acting alone.

The Company has a process in place to evaluate the potential for interacting threats. This is described in Sections 8.1 and 8.2. Interactive threats are defined as more than one threat occurring on a section of pipeline at the same time that together are more severe than occurring separately.

8.1 Interactive Threats

The Company shall use Table 5 to determine the potential threat interactions that could potentially have a more adverse effect. Table 5 defines a threat as non-interactive (Category 1), or interactive (Category 2), or potentially interactive under certain conditions (category 1*). The approach does not try to determine a relative risk score for each of the interacting threats, but provides guidance for the application of additional mitigative measures.

Threats are considered to interact if the presence of both threats on a pipeline segment is perceived to increase the likelihood of failure more than the sum of the two threats acting alone.

TABLE 5. INTERACTIVE THREATS

		A	B	C	D	E	F	G	H	I	J
	Threat	Internal Corrosion	SCC	Manufacturing defects incl. defective pipe	Damaged Pipe (dents, buckles)	Girth Weld /Fab	Equipment	Third party mech damage	Incorrect Operations	Weather Related and Outside Force	Low Frequency ERW Pipe Threat
1	External Corrosion	1	1	1*	1	1	1	1	2	1	1*
2	Internal Corrosion		1	1*	1	1	2	1	2	1	1*
3	SCC			1	2	1	1	2	2	2	1
4	Manufacturing defects incl. defective pipe				2	1	1	1	1	1	N/A
5	Damaged Pipe (dents,buckles)					2	1	1	1	2	2
6	Girth Weld/Fab						1	1	1	2	1
7	Equipment							1	2	2	1
8	Third party mech damage								2	1	1
9	Incorrect Operation									1	1
10	Weather Related and Outside Force										1

Where there is conditional interaction of threats the Company shall review leak records to see if that threat combination has resulted in any previous failures; if any previous failures have occurred, the threat combination shall be considered interacting. Where interacting threats are identified, P&M measures shall be used to address the interacting threats.

Cyclic fatigue interaction is not considered in Table 5. Section 8.2 provides a procedure for consideration of cyclic fatigue interactions.

8.2 Cyclic Fatigue

Cyclic fatigue is an example of an interacting threat resulting from the presence of features that are sensitive to cyclical stresses that are exposed to operating conditions where cyclical stresses could be present. Features that are sensitive to cyclical stress include:

- Longitudinal weld cracks
- Dents
- Mechanical damage
- Large areas of corrosion[1]
- Environmental cracking
- Wrinkle bends, miters, or buckles
- Unrestrained piping
- Pipe spans
- Cantilevered masses (unsupported valves or other equipment)
- Structural discontinuities (e.g., abrupt weld toe geometries or weld bead profiles, large differences in material strength between weld and base metal, branch openings, adjacent thick and thin shell segments)

Cyclic stresses include vibration, periodic external loading, large temperature changes, or frequent large internal pressure fluctuations. Locations where cyclic stresses may occur include:

- Compressor stations
- Above-ground piping with high gas flow rates
- Pipe spans exposed to fluid currents (wind or water) flowing perpendicular to the pipe
- Piping experiencing thermal expansion
- Structural vibrations (e.g., bridges) associated with above-ground piping, unrestrained piping, or spans

Appendix C contains the process for evaluating fatigue. The following assumptions shall be applied when using the fatigue evaluation process:

- Identification of events where cyclic stress was a root cause. If there has been an event, both the feature/defect that was affected by cyclical stress and the source of the cyclical stress are identified.
- Determination of the uniqueness of events. If events have occurred, each event is reviewed to determine if either the feature/defect or loading condition was unique or if other similar features/defects and loading conditions exist. Remediation programs are

[1] The screening criteria for evaluating whether a corroded area could be susceptible to cracking are: Length greater than the equivalent of $(20Dt)^{0.5}$, where D is diameter and t is wall thickness, and an average depth of more than 50% wall thickness. The length criterion is borrowed from the Original B31G equations for evaluating remaining strength due to metal loss, and is used in this context to describe a corroded length that is long enough that no reinforcement is provided by the surrounding metal.

developed where systemic concerns exist (see Section 8.1.1 for additional details regarding remediation programs).

- Identification of features in the HCA segment that might be sensitive to cyclical stress. These features are identified above. Additionally the existence of the following pipe types is identified:
  * Pipe manufactured by A.O. Smith (flash-welded) or Youngstown Sheet & Tube (direct-current ERW)
  * Low-frequency ERW pipe
  * Submerged arc welded pipe that may have been loaded in such a way as to produce transportation fatigue cracks.
- Identification of sources of cyclical stress. These sources are described above and include:
  * Pressure cycles
  * Observable vibration or movement of above-ground piping or spans (structural vibration)
  * Temperature fluctuations
  * Wind or water currents.
- Determination of the threat from operational pressure fluctuations, using Equation 1:

[illegible] 1.21 [illegible]

Equation 1

where

* N is the number of full maximum operating pressure cycles (i.e., maximum operating pressure to zero to maximum operating pressure)
* F is the design factor or the ratio of the maximum operating pressure to the pressure corresponding to 100% SMYS
* SMYS is the specified minimum yield strength (ksi)
* OD is the outside diameter (inches)
* WT is the wall thickness (inches)

N is compared to the estimated number of lifetime full maximum operating pressure cycles to be experienced as determined by:

* Using job records indicating when line clearances occurred and a conservative estimate of smaller operational cycles that may be equivalent to full maximum operating pressure cycles, or
* Using rainflow-cycle counting and accumulation of full maximum operating pressure cycles using the Palgren-Miner Rule. ***Note*** the representative period of operational history used for rainflow-cycle counting may not reflect line clearances for maintenance activities, so a combination of job records research and rainflow-cycle counting may be used based upon SME discretion.

If N is less than the estimated number of lifetime full maximum operating pressure cycles that the segment will experience, then pressure-cycle-induced fatigue is considered a potential threat and further analysis is necessary.

Note: Equation 1 is based upon a regression analysis of fatigue-life calculations for a range of pipe D/t rations, grades, operating stress levels, and represents the cycles to failure (taken as 90% wall thickness) for a 50% through-wall, $2(Dt)^{0.5}$ longitudinal flaw using published crack-growth rate parameters (API 579) and the Paris Law for calculating crack growth.

- If features susceptible to cyclical stress are present and cyclical stresses that could initiate and/or propagate a crack exist, then a remediation plan shall be developed (see Section 8.1.1 regarding remediation plans).
- If features susceptible to cyclical stress are present, but cyclical loading conditions are not present, the operating conditions shall be monitored to detect changes that could lead to a potential fatigue threat.
- If sources of cyclical threat were identified, it shall be determined whether the cyclical stresses could affect features such as girth welds or other features that could concentrate stress. This is performed through a site-specific fatigue analysis that considers the amplitude and frequency of the cyclical stress, and the resistance of potentially susceptible features (such as girth welds) to fatigue-crack initiation.

8.2.1 Remediation Plan

A remediation plan shall be developed as determined by the cyclic fatigue evaluation process described above. The remediation plan should include performing an integrity assessment to evaluate features that have been identified as susceptible to cyclical stresses for that covered segment. The integrity assessment shall be performed as described in RMP-06.

9.0 THREATS REQUIRING INTEGRITY ASSESSMENTS

Integrity assessments as described in RMP-06 are required to assess for certain identified threats. Other processes, including P&M measures, may be used to address other identified threats.

The Company requires an integrity assessment for the following threats when they are identified as a threat according to Section 7 of this procedure:

- EC
- IC
- SCC
- M (unstable, high-risk)
- C (unstable, high-risk)

The Company uses P&M measures or other processes to address the following threats:

- M (stable)
- C (stable)
- E
- TPD
- IO
- WROF

Sections 7.4 and 7.5 of this procedure shall be used to determine the stability of M&C threats.

While TPD is normally assessed using P&M measures, an integrity assessment may be required based on the results of the risk assessment. RMP-03, Third Party Damage Threat Algorithm, describes the determination of the likelihood of failure (LOF) score related to TPD. RMP-06, Risk Management Procedure, provides the requirements for performing an integrity assessment based on the LOF score.

P&M measures that may be used to address various threats are identified in RMP-06 and RMP-17, Long Term Integrity Management Program. Other processes that may be used to assess for various threats include, but are not limited to:

- Surveys to consider such factors as land movement, pipe movement, and outside forces,
- Procedure reviews and audits, including welding and operations and maintenance procedures
- ECAs

10.0 DOCUMENTATION

The data used for threat identification process shall be documented in the Risk and Threat database.

The results of the threat identification process shall be documented in the Baseline Assessment Plan (BAP) and also upload into GIS.

11.0 REFERENCES AND SUPPORTING DOCUMENTS

1. RMP-06, Gas Transmission Integrity Management Program
2. RMP-17, Long Term Integrity Management Program
3. Final Report 12-012, “Procedure for Evaluating the Stability of Manufacturing and Construction Defects”, Kiefner & Associates, Inc., 2012.
4. Final Report 11-110, “Procedure for Evaluating the Fatigue Threat”, Kiefner & Associates, Inc., 2011.
5. Final Report 11-129, “Assessment of Potential Threat Interactions”, Kiefner & Associates, Inc., 2011.

12.0 ACRONYMS

ASME American Society of Mechanical Engineers

BAP Baseline Assessment Plan

CFR Code of Federal Regulations

CIS Close Interval Survey

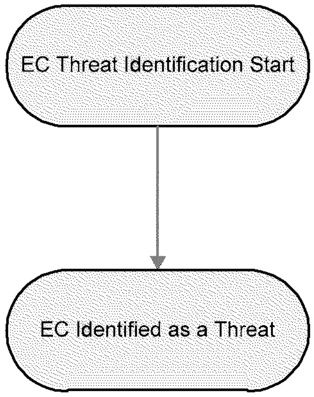
CP Cathodic Protection

DA Direct Assessment

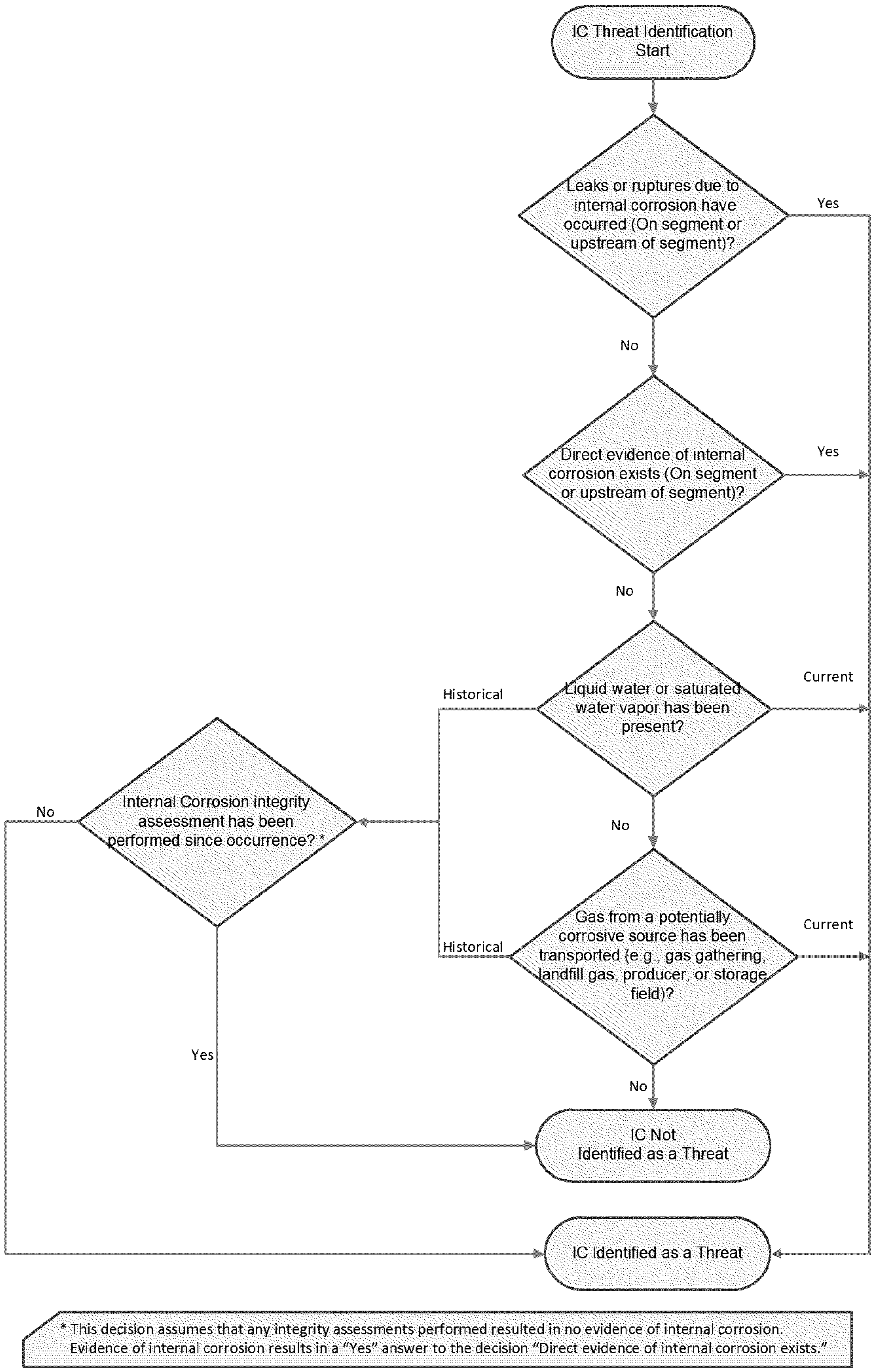
ECA	Engineering Critical Analysis
GIS	Geographic Information System
HCA	High Consequence Area
ILI	In-Line Inspection
O&M	Operations and Maintenance
P&M	Preventive and Mitigative
RCA	Root Cause Analysis
RMP	Risk Management Procedure
SME	Subject Matter Expert

APPENDIX A. THREAT IDENTIFICATION DECISION TREES

A-1: EXTERNAL CORROSION THREAT



A-2: INTERNAL CORROSION THREAT



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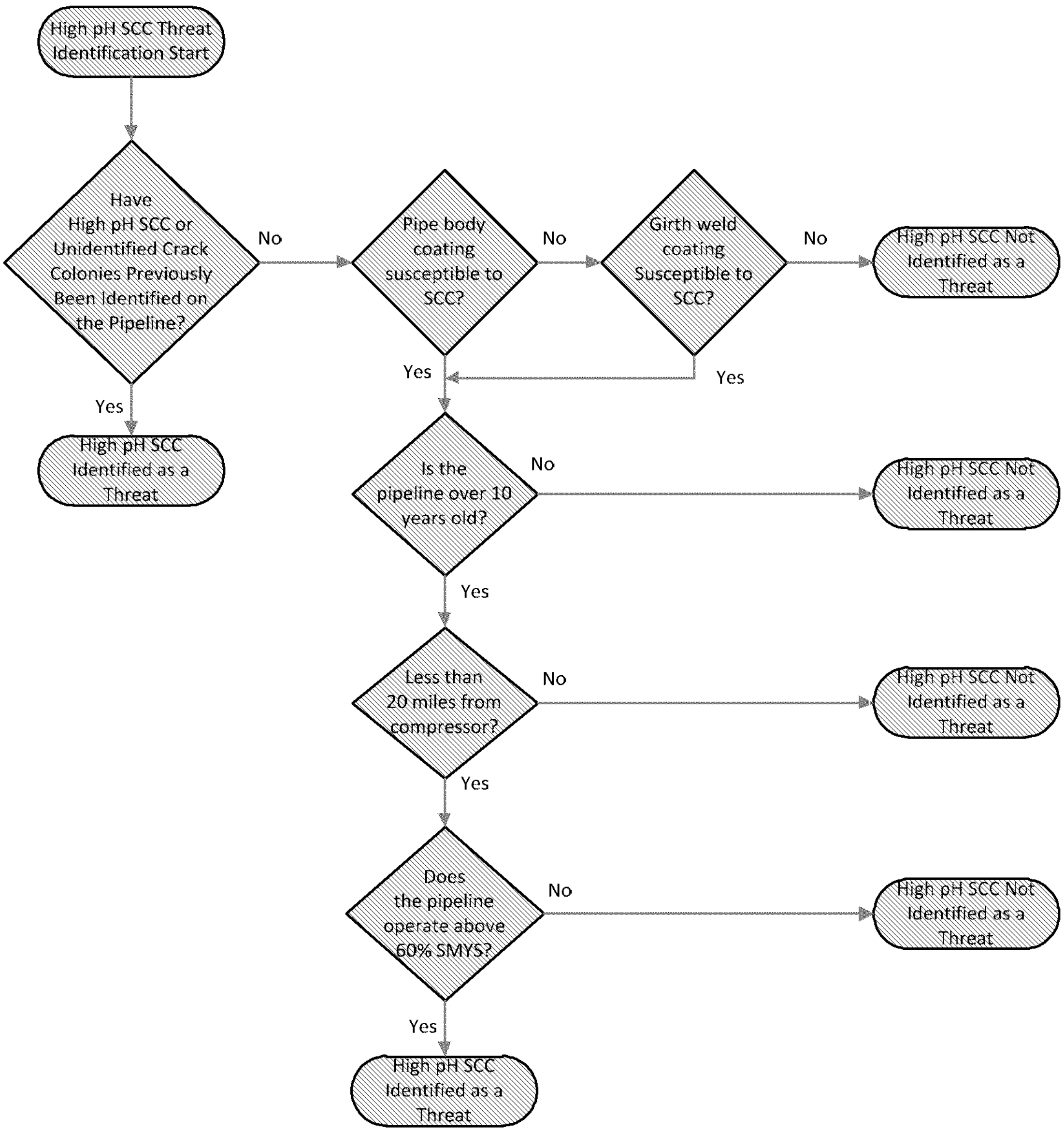
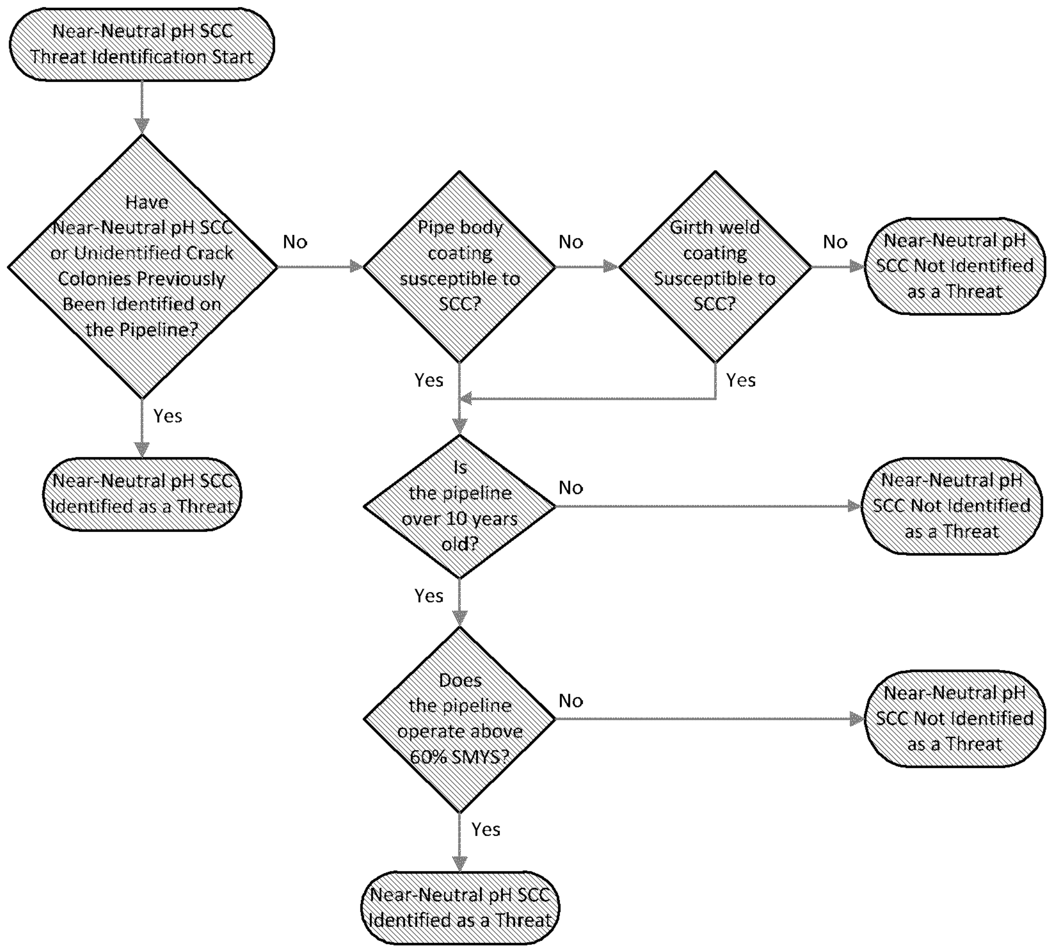
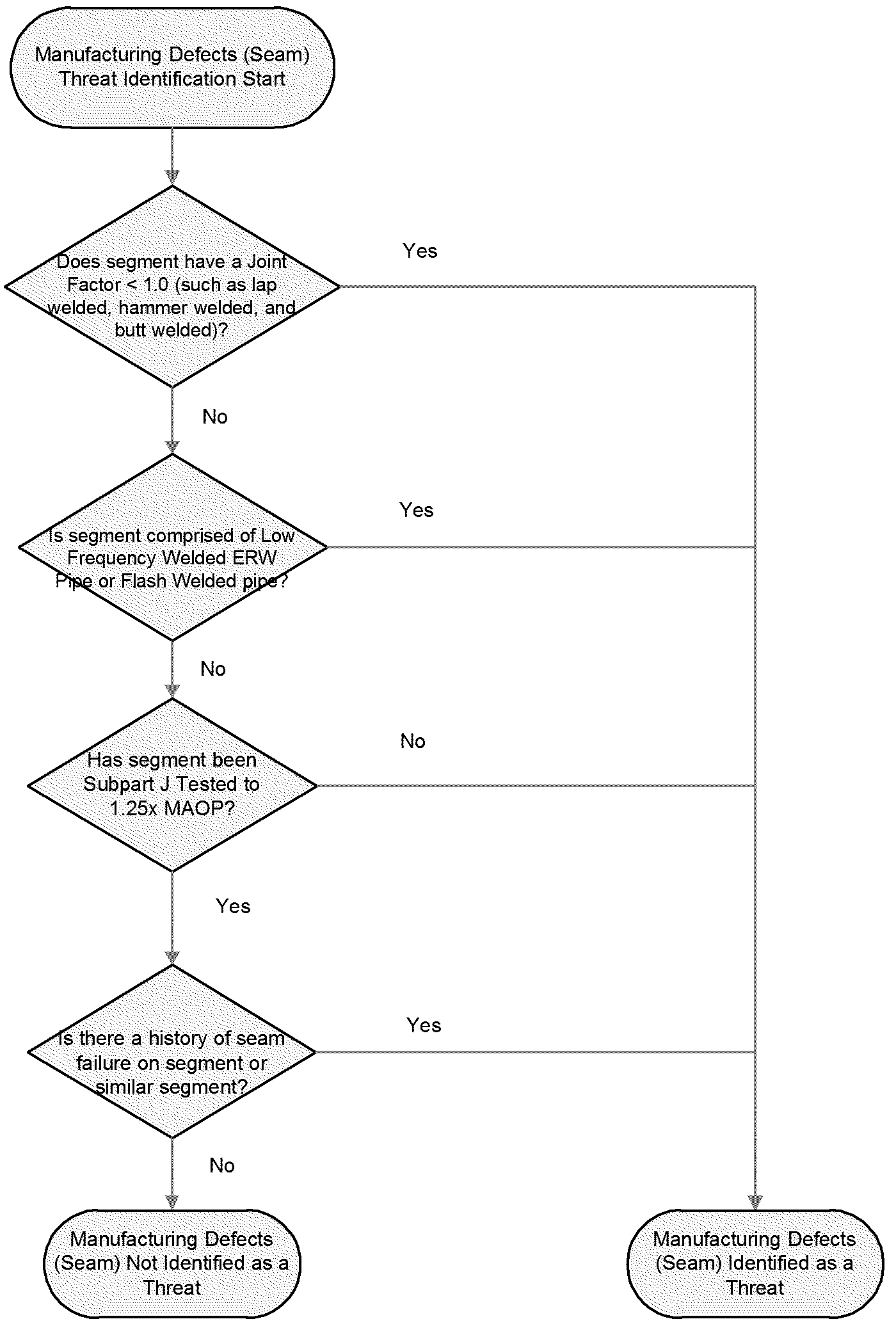
A-3: HIGH PH STRESS CORROSION CRACKING THREAT



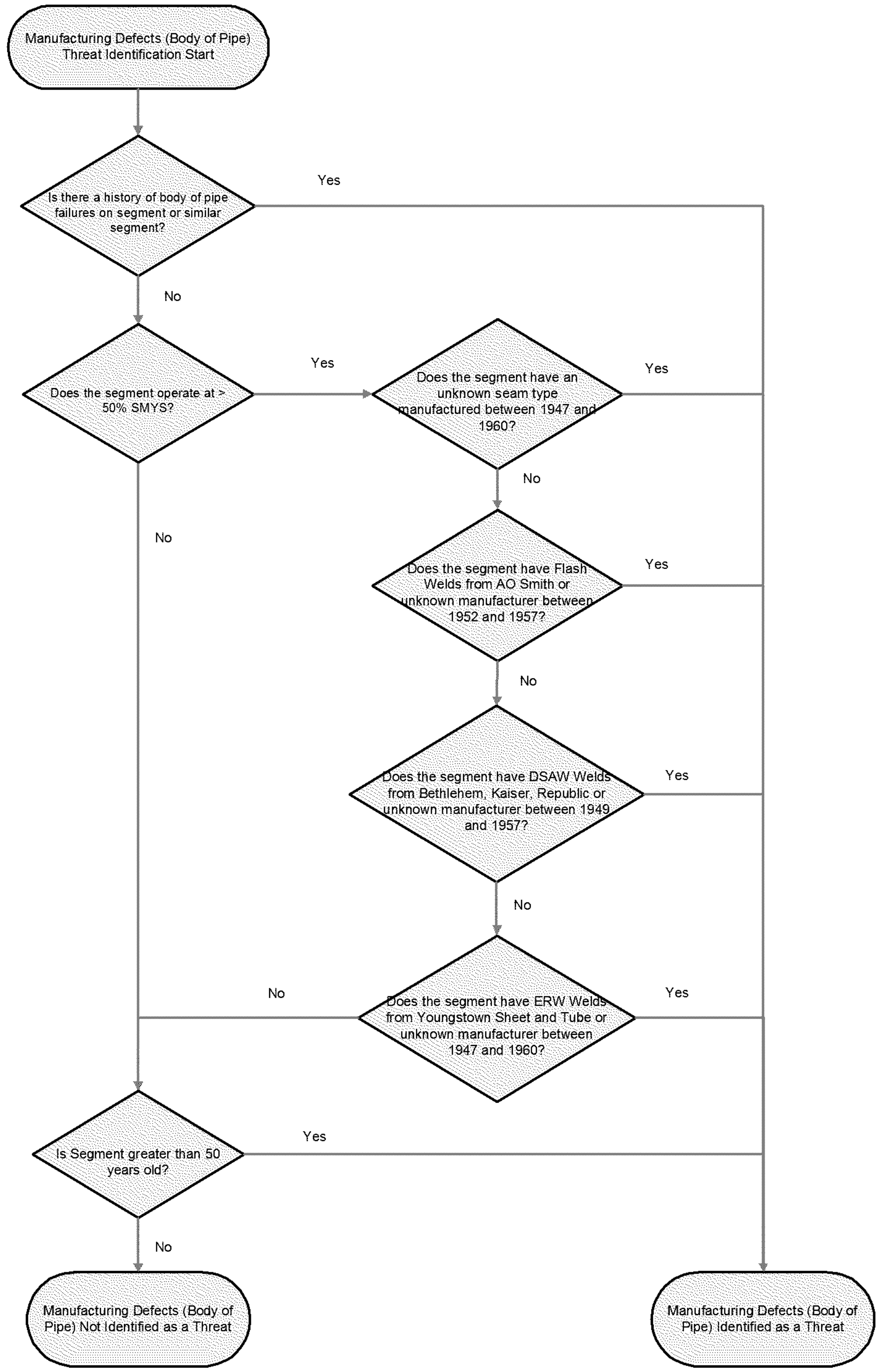
A-4: Near-Neutral pH Stress Corrosion Cracking Threat



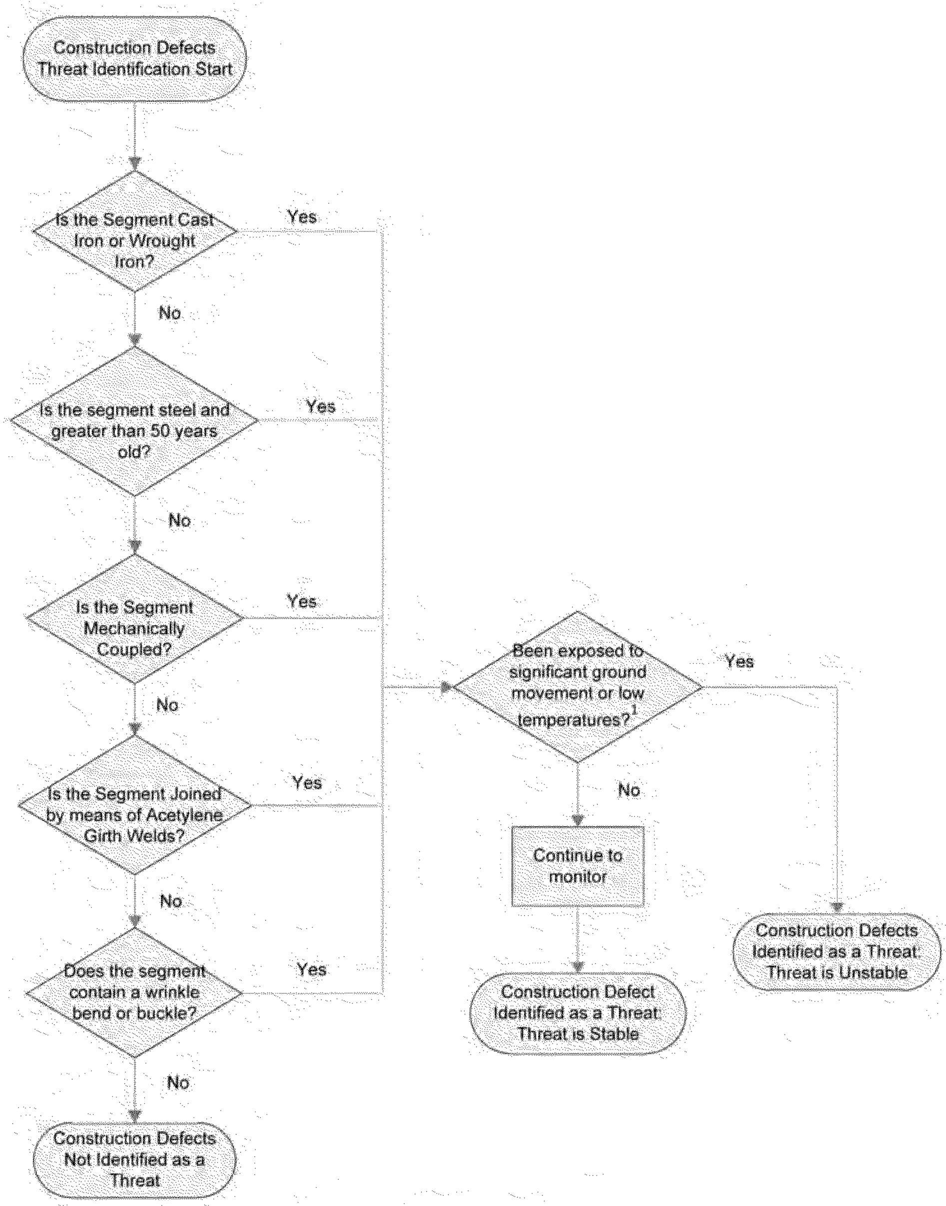
A-5: MANUFACTURING DEFECT (SEAM) THREAT



A-6: MANUFACTURING DEFECT (BODY OF PIPE) THREAT

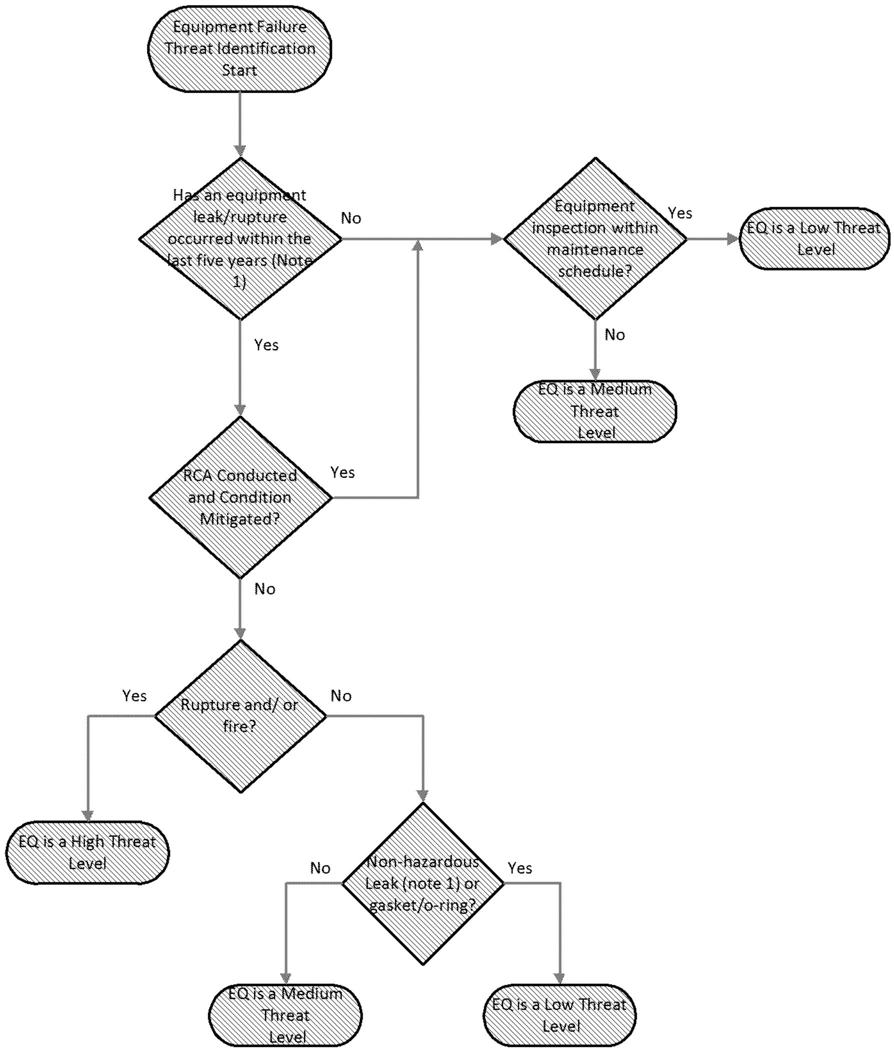


A-7: CONSTRUCTION THREAT



[1] Defined as:
(i) A Fault crossing and a seismic event (Magnitude >6.0) coupled with ground faulting or
(ii) A seismic event with ground acceleration ≥ 0.5g or
(iii) Levee Crossings in the Delta list from the enterprise risk management (ERM) study that are susceptible to failure and with ground acceleration ≥ 0.2g or
(iv) Known liquefaction area and a seismic event with ground acceleration ≥ 0.2g or
(v) Known slope instability area and a seismic event with ground acceleration ≥ 0.2g or
(vi) Known landslides or washouts that are activated by intense or long duration rainfall (monitored as part of RMI-04A)
(vii) Pipe exposed due to excavation

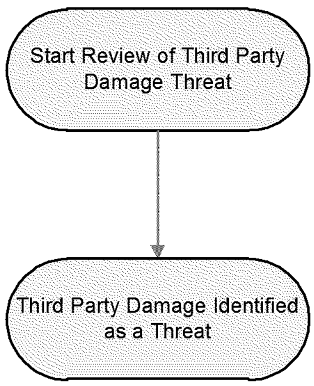
A-8: EQUIPMENT THREAT



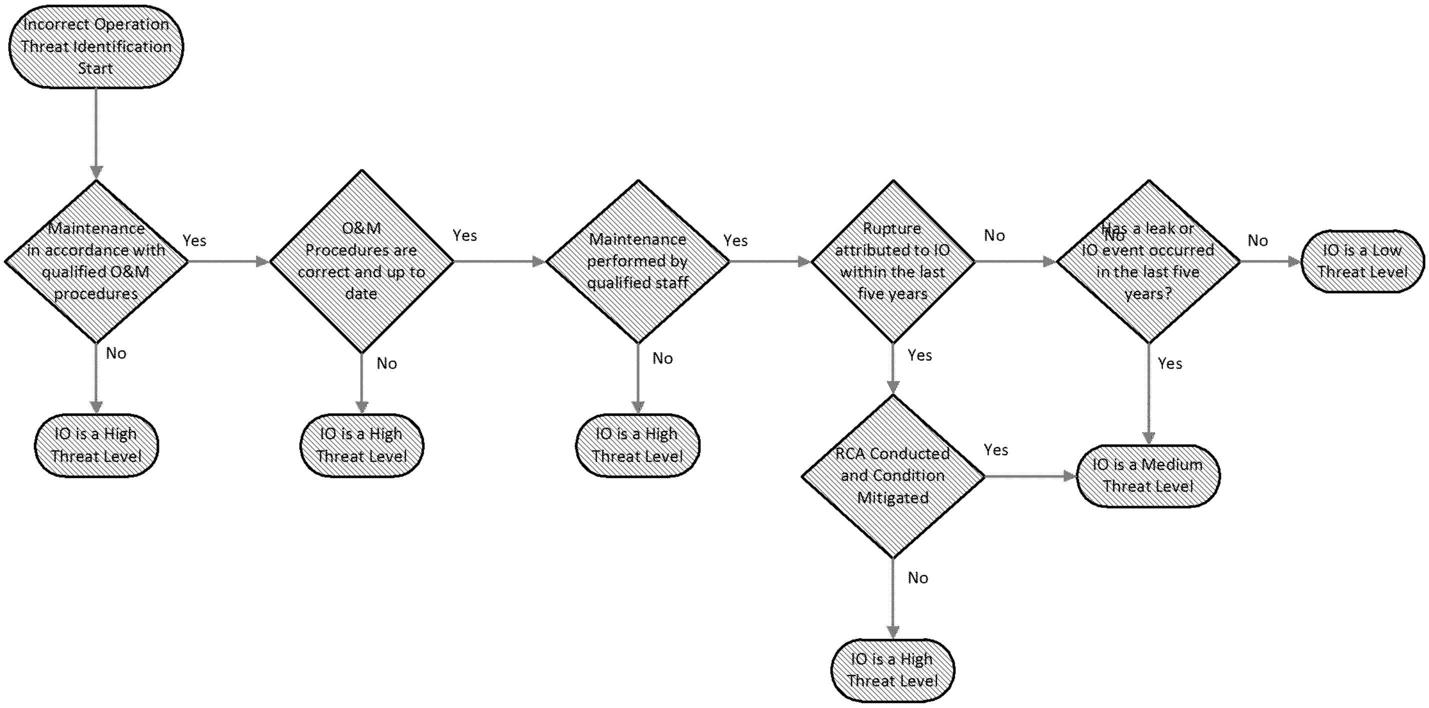
Guidance:

- PG&E considers the threat of equipment failure to always exist. This threat identification flowchart is meant to determine the likelihood of an equipment failure event.
- If information is not available, then the most conservative decision should be taken at each decision point.
- "Equipment is defined in this context as pipeline facilities other than pipe and pipe components" (ASME B31.8S – 2004).
- An equipment failure is defined as any leak or unplanned stoppage of operation attributed to equipment.
- Possible locations of equipment failures per ASME B31.8S – 2004: pressure control and relief equipment, gaskets, O-rings, and seal/pump packing. Additional locations of equipment failures are possible.
- Data to collect per ASME B31.8S - 2004: year of installation of equipment, regulator valve information, relief valve information, flange gasket information, regulator set point drift (outside of manufacturer's tolerances), relief valve set point drift, O-ring information, and seal/packing information. Information relating to any equipment failure should also be collected.
- Manufacturers of valves, gaskets and seals that have experienced failure(s) or not met the design life of the equipment should receive more frequent inspection across PG&E's system.
- Set point drift traditionally occurs from thermal expansion of the valve due to a difference in temperature at calibration and operation. Valves that have experienced set point drift should receive more frequent inspection across PG&E's system.
- **Note 1:** A "leak" is defined as an unintentional escape of gas from the pipeline. A non-hazardous release that can be eliminated by lubrication, adjustment, or tightening, is not a leak. (Per PHMSA F 7100.1-1 Rev. 01/11)

A-9: THIRD PARTY DAMAGE THREAT



A-10: INCORRECT OPERATIONS THREAT



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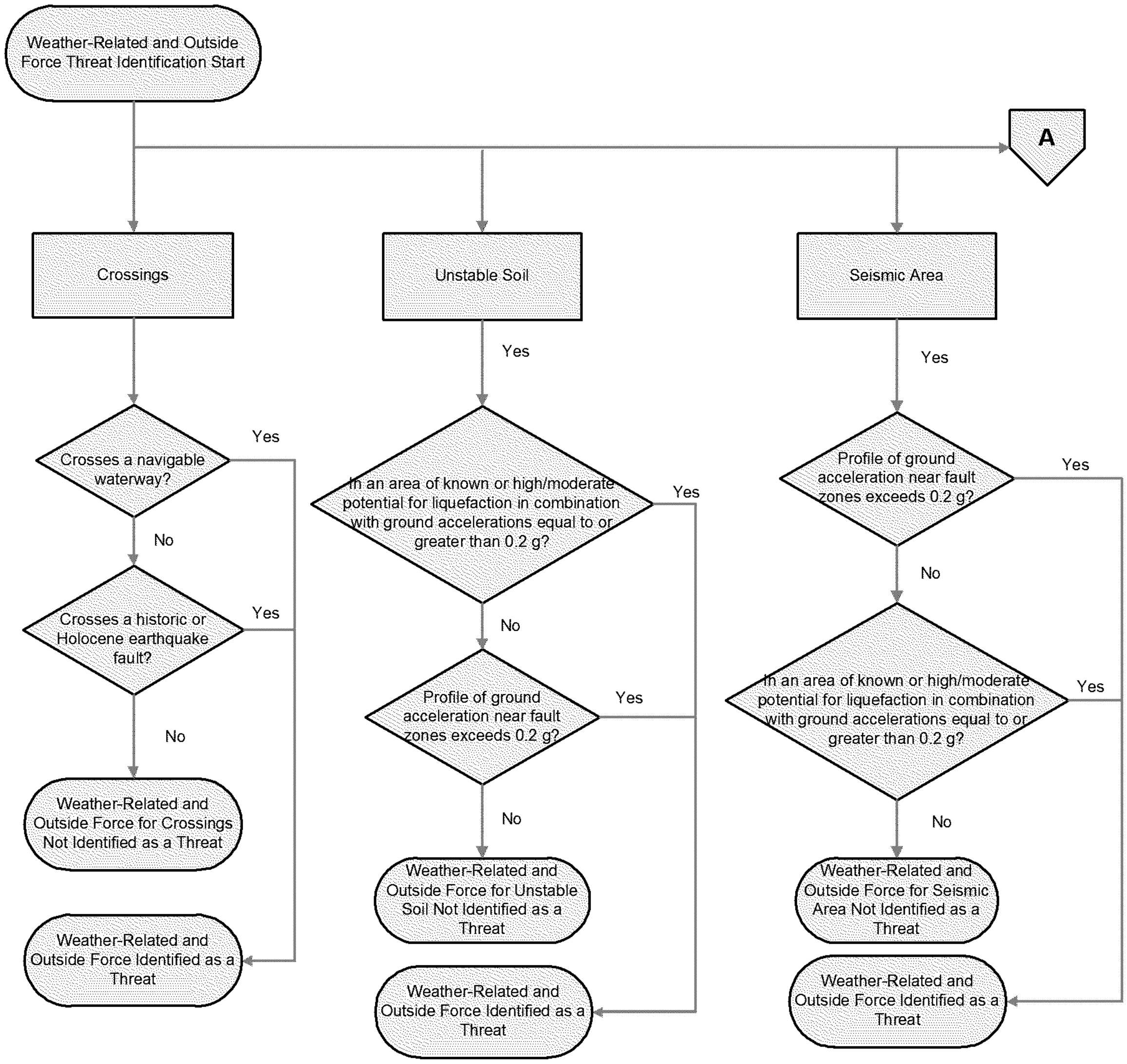
A-11: Weather-Related and Outside Forces Threat



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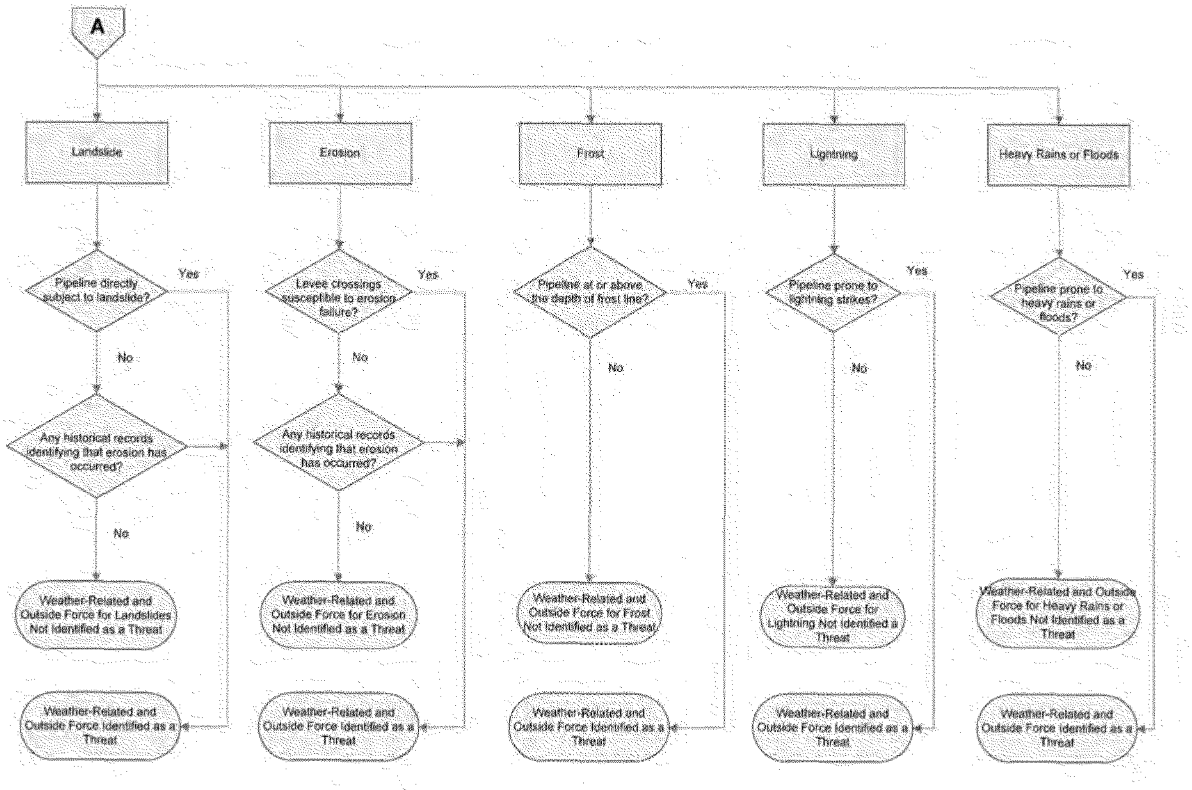
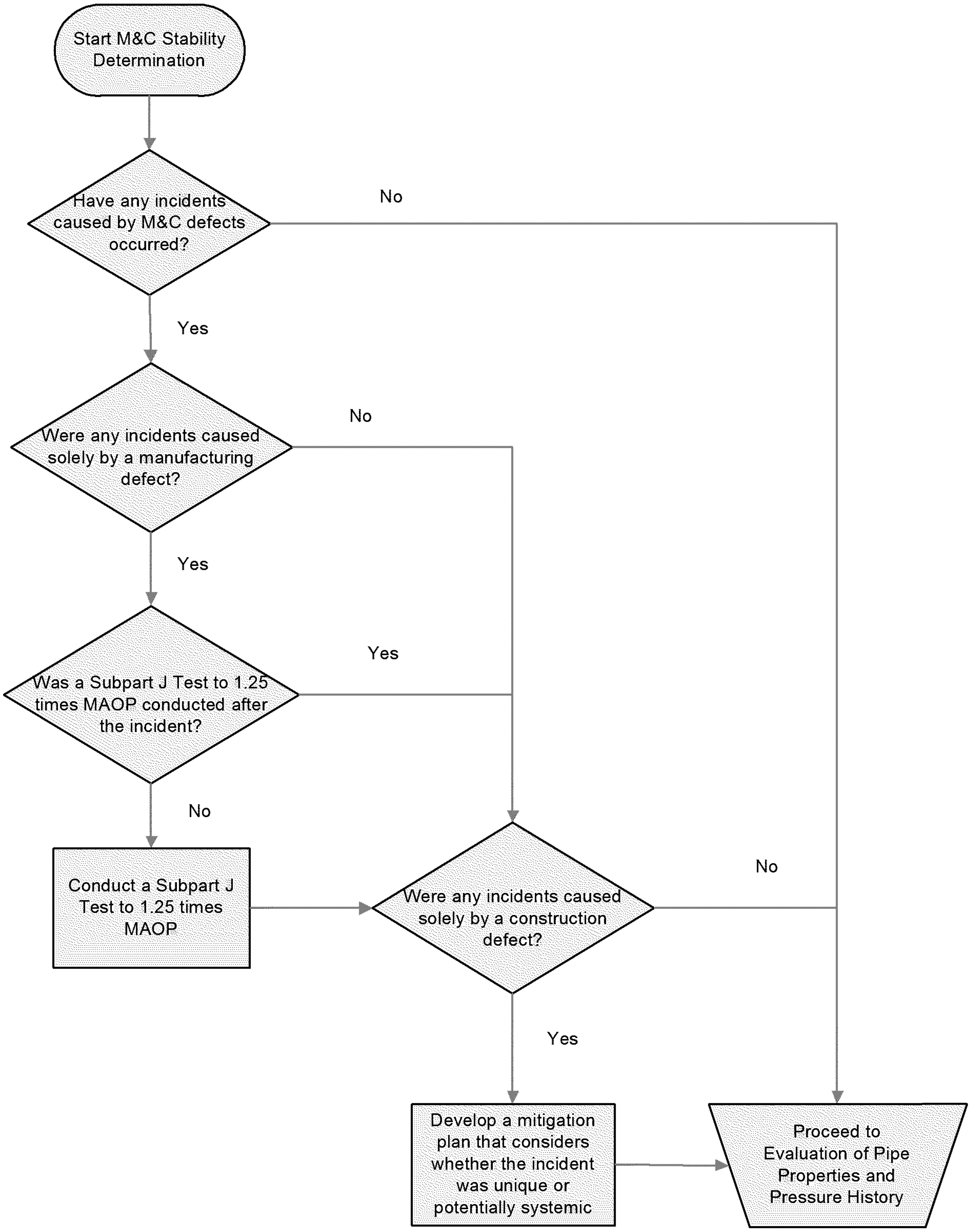
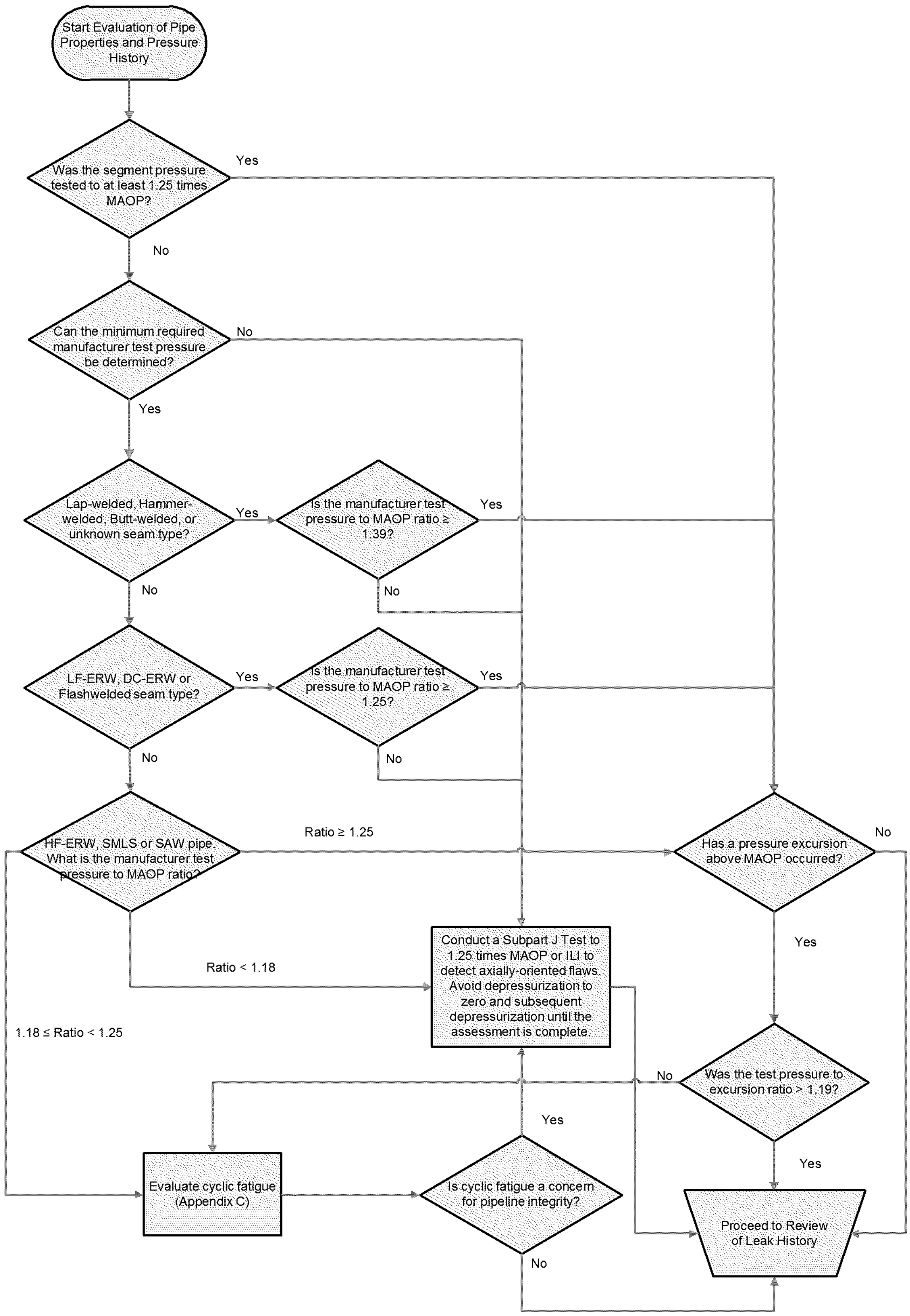

A
Landslide
Erosion
Frost
Lightning
Heavy Rains or Floods
Pipeline directly subject to landslide?
Levee crossings susceptible to erosion failure?
Pipeline at or above the depth of frost line?
Pipeline prone to lightning strikes?
Pipeline prone to heavy rains or floods?
Yes
No
Any historical records identifying that erosion has occurred?
Any historical records identifying that erosion has occurred?
Weather-Related and Outside Force for Landslides Not Identified as a Threat
Weather-Related and Outside Force for Erosion Not Identified as a Threat
Weather-Related and Outside Force for Frost Not Identified as a Threat
Weather-Related and Outside Force for Lightning Not Identified a Threat
Weather-Related and Outside Force for Heavy Rains or Floods Not Identified as a Threat
Weather-Related and Outside Force Identified as a Threat

APPENDIX B. MANUFACTURING AND CONSTRUCTION DEFECT STABILITY EVALUATION


Start M&C Stability Determination
Have any incidents caused by M&C defects occurred?
No
Yes
Were any incidents caused solely by a manufacturing defect?
No
Yes
Was a Subpart J Test to 1.25 times MAOP conducted after the incident?
Yes
No
Conduct a Subpart J Test to 1.25 times MAOP
Were any incidents caused solely by a construction defect?
No
Yes
Develop a mitigation plan that considers whether the incident was unique or potentially systemic
Proceed to Evaluation of Pipe Properties and Pressure History



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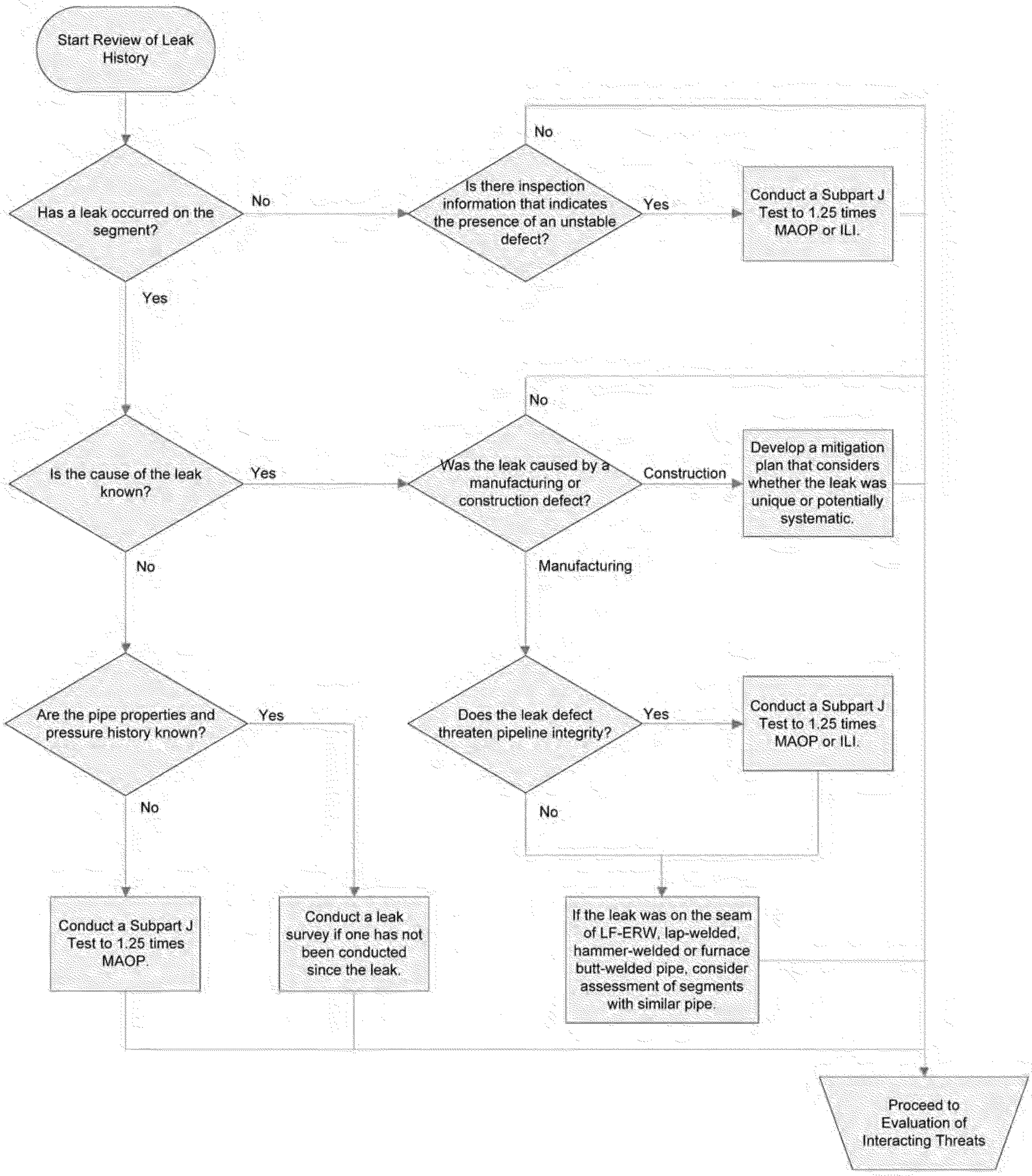

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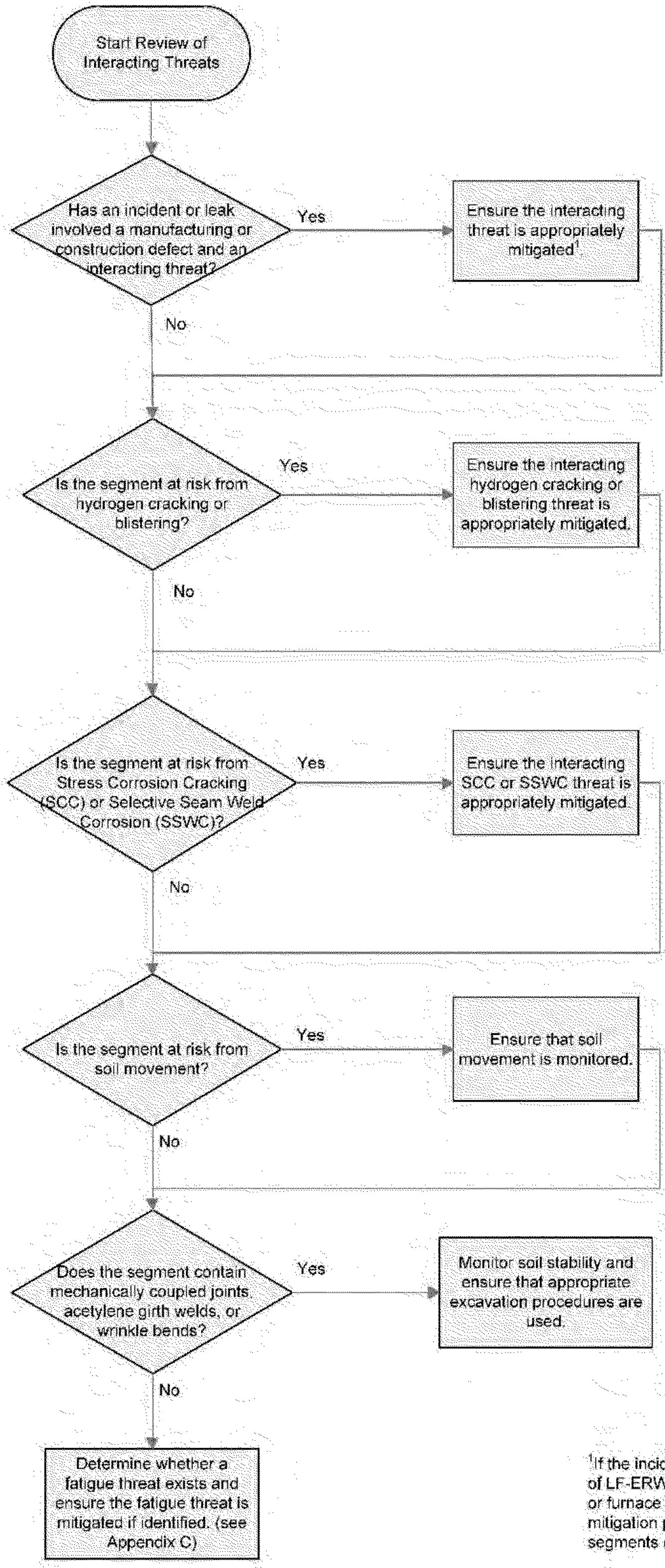
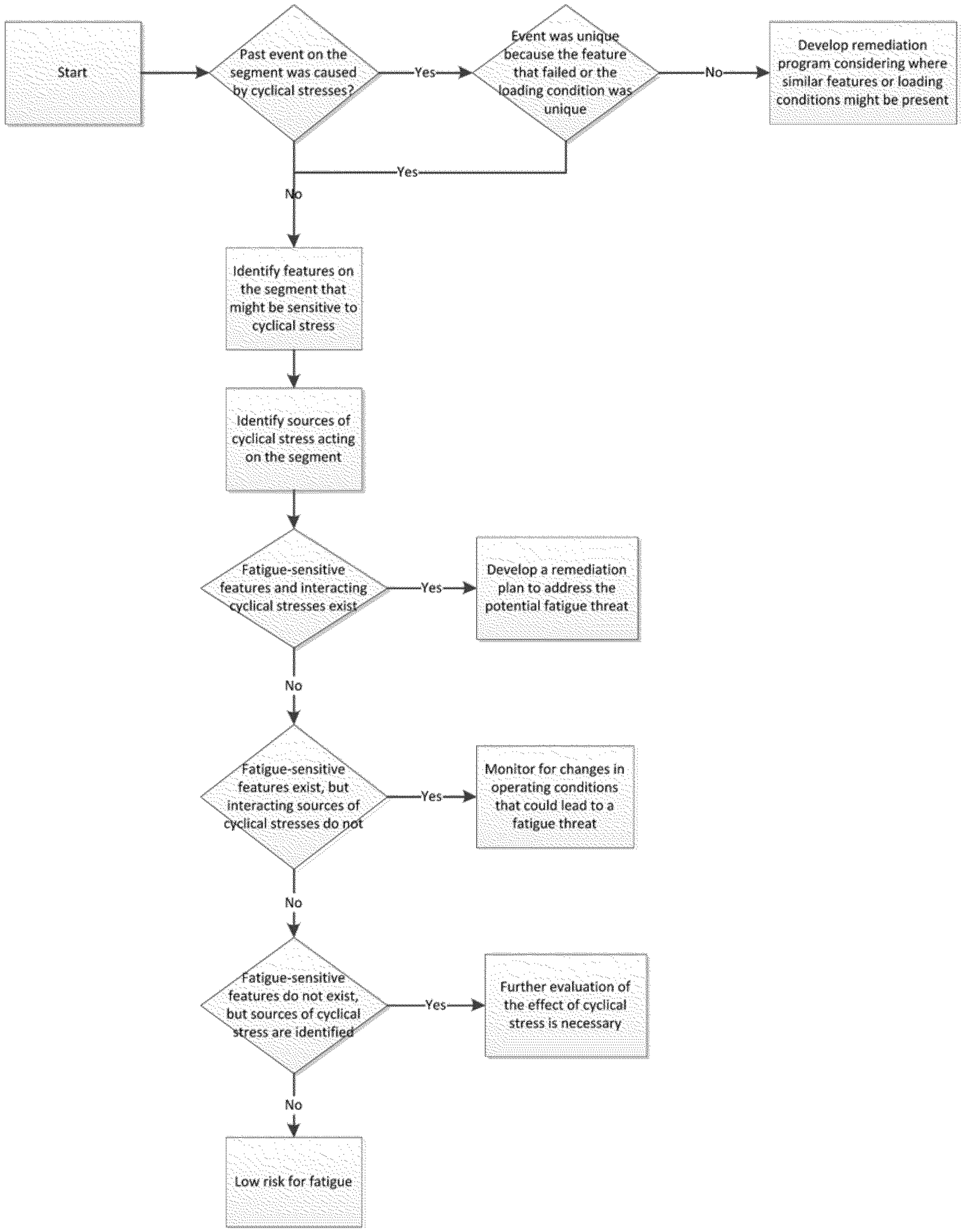


[1]If the incident or leak involved the seam of LF-ERW, lap-welded, hammer-welded or furnace butt-welded pipe, then the mitigation plan should include evaluating segments containing similar pipe.

APPENDIX C. CYCLIC FATIGUE EVALUATION PROCESS

Cyclic Fatigue Evaluation Decision Tree



PACIFIC GAS AND ELECTRIC COMPANY

GAS OPERATIONS

PUBLIC SAFETY & INTEGRITY MANAGEMENT

Risk Management Procedure

Procedure No. RMP-19
Revision 0
Incorrect Operations and Equipment Failure Threat Algorithm

Gas Integrity Management Program
for PG&E and Standard Pacific Gas Line, Inc.

Prepared By: Redacted Date: 8/10/12
Redacted Risk Management Supervisor

Concur: Redacted Date: 8/14/12
Redacted, Integrity Management Engineering Manager

Concur: Date: 8/14/12
Bennie Barnes, Director, Transmission Integrity Management

Concur: Date: 8/14/12
Sanford Hartman, Vice President, Managing Director, Law

Approved By: Roland Trevino Date: 8/14/2012
Roland Trevino, Vice President, Public Safety & Integrity Management

			Prepared by	Approved by	Approved by	Approved by	Approved by
Rev. No.	Date	Description	Risk Management Supervisor	Integrity Management Engineering Manager	Director, Transmission Integrity Management	Vice President, Managing Director, Law	Vice President – Gas Engineering & Operations
0	8/14/12	Initial Issue	Redacted	Redacte	B2BY	SLHB	RIT4

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1.0 PURPOSE

The purpose of this procedure is to establish the incorrect operations and equipment failure threat algorithms for the determination of Likelihood of Failure for PG&E's Gas Transmission and Distribution Integrity Management Program, described in RMP-06 and RMP-15.

2.0 SCOPE

2.1 Transmission

This guideline applies to all of PG&E's gas transmission pipeline facilities and is to be used in conjunction with RMP-01, Risk Management Procedure. The algorithms described in this procedure are used for transmission pipelines and associated appurtenances, per RMP-01. The results are communicated to the Gas Transmission Integrity Management Program (TIMP), whose risk management processes are designed to meet the requirements of 49 CFR 192 Subpart O. The TIMP group performs a risk assessment to identify and prioritize risks for transmission pipelines per RMP-06.

2.2 Distribution

The algorithms described in this procedure are also used for distribution pipelines and associated appurtenances operating over 60 psig. The results are communicated to the Gas Distribution Integrity Management Program (DIMP), whose risk management processes are designed to meet the requirements of 49 CFR 192 Subpart P. The DIMP group performs a risk assessment to identify and prioritize risks for distribution pipelines per RMP-15.

3.0 INTRODUCTION

As required by RMP-01, RMP-06, and RMP-15, this procedure (RMP-19) supports the calculation of risk due to potential incorrect operations and equipment failure threats.

RMP-01 describes Risk as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). A relative risk assessment model is used to establish risk for all pipeline segments within the scope of RMP-01.

LOF is defined as the sum of the following threat categories:

- External corrosion (EC)
- Internal corrosion (IC)
- Stress corrosion cracking (SCC)
- Third party damage (TPD)
- Weather-related and outside forces (WROF)
- Manufacturing (M)
- Construction, including welding/fabrication-related risks (C)

- Equipment (E)
- Incorrect operations (IO)

Where Manufacturing and Construction are handled together, they are abbreviated M&C.

See RMP-15 for equivalent identified distribution threats, per 49 CFR 192.1007.

For each threat category, the appropriate steering committee identifies the significant factors that influence the LOF for that threat. (For a discussion of steering committees, see RMP-01.)

4.0 ROLES AND RESPONSIBILITY

The Integrity Management Group is responsible for managing risk within the scope of this procedure. The Integrity Management Group shall establish and manage the risk of each pipeline facility using methodologies that are

- consistent with industry practice
- acceptable to regulatory agencies
- appropriate for PG&E's gas facilities
- in conformance with this procedure

Specific responsibilities for ensuring compliance with this procedure are as follows:

Title	Reports to	Responsibilities
Risk Management Supervisor	Integrity Management Risk Manager	• Supervise completion of work (schedule/quality) • Monitor compliance with procedure and take corrective actions as necessary. • Analyze and communicate risk assessment results • Ensure training of assigned individuals
Risk Management Engineers	Risk Management Supervisor	• Perform calculations per procedure • Analyze and communicate risk assessment results • Identify need for changes

5.0 TRAINING AND QUALIFICATIONS

5.1 Training

Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training	How Often
Risk Management Supervisor	Procedure review of RMP-01 and RMP-19	• Upon initial assignment • Once each calendar year
Incorrect Operations and Equipment Failure Steering Committee Chairman	Procedure review of RMP-01 and RMP-19	• Upon initial assignment • Once each calendar year • As changes are made to the procedure
Incorrect Operations and Equipment Failure Steering Committee Members (Subject Matter Experts)	Review RMP-19 and Steering Committee requirements of RMP-01	• Once each calendar year at the time of the steering committee meeting
Risk Management Engineers	Per RMP-06 and RMP-15 requirements; review RMP-19	• Upon initial assignment • Once each calendar year • As changes are made to the procedure

5.2 Qualifications

See RMP-06 and RMP-15 for qualification requirements.

6.0 INCORRECT OPERATIONS THREAT ALGORITHM

An Incorrect Operation (IO) is defined as any activity, or omission of an activity, by company personnel, that could adversely affect the safety or reliability of the pipeline. Incorrect operation events include, but are not limited to:

- Over-pressure events
- Work procedure errors
- Human performance factors

Scoring for the IO threat algorithm shall be calculated per the direction of the Incorrect Operations Steering Committee. The committee has determined that the factors listed as A through G of this section are significant for determining LOF due to IO. Other factors in risk to transmission and distribution above 60 psig pipeline segments may be considered by the Incorrect Operations Steering Committee, based upon newly-available information, and included in the algorithm. These determinations are regularly reviewed and subject to change per RMP-01.

The LOF for IO is calculated by:

1. Assigning points to each factor based on maintenance and operating records, assessment results, and pipeline attribute information.
2. Multiplying the assigned points by the weighting for the factor, as established by the Incorrect Operations Steering Committee. This product is the contribution for the factor.
3. Summing the factor contributions. This sum is the LOF for IO individually.

Before applying the algorithm, the Risk Management Engineer shall evaluate the list of factors and determine whether any factors should be added, removed or modified. Changes to factors, point values, and other aspects of the risk algorithm are performed per RMP-01 and the Management of Change (MOC) process described in RMP-06.

The Risk Management Engineer assigns points to each pipeline segment in accordance with the factor tables below. Points are assigned using all available data including manufacturing and construction records and results of inspections and testing.

Where multiple criteria apply, the criterion with the highest point value is used. The factors for IO are as follows.

A) **Historic Leaks Due to Incorrect Operations Factor**(25% weighting)
Pipeline segments with a history of operating leaks in the last 5 years due to incorrect operation exhibit a greater susceptibility for the occurrence of future leaks of a similar nature.
Points are assigned as follows:

Criteria	Points	Contrib.
History of operating leaks	100	25
No such history*	0	0

* Default

B) **Historic Incorrect Operations Event, Not Resulting in a Leak Factor**(25% weighting)
Pipeline maintenance divisions with a history of incorrect-operations-related events in the last 5 years exhibit a greater susceptibility for the occurrence of future events of a similar nature.
Points are assigned as follows:

Criteria	Points	Contrib.
6 or more events	100	25
5 events	90	22.5
4 events	80	20
3 events	70	17.5
2 events	60	15
1 event	50	12.5
No event*	0	0

* Default

C) **Training Factor**(12% weighting)
Training is important to the prevention of work procedure errors. A training program should establish minimum requirements for subject matter appropriate to personnel roles or responsibilities, and should include testing and periodic re-training to verify continued subject matter knowledge. Training elements that should be considered include:

* control and operations
* maintenance procedures
* emergency drills
* leak detection

Points are assigned as follows:

Criteria	Points	Contrib.
Effective training programs are not in place	100	12
Training exist, but inconsistences with implementation are documented*	80	9.6
All training elements addressed in program	0	0

* Default

D) **Supervisory Control and Data Acquisition (SCADA) Factor** (10% weighting)

SCADA is a pipeline control system that gathers information such as pipeline pressures and flow rates from remote locations, and regularly transmits this information to a central control facility for monitoring, analysis and remote control, as needed, of pipeline components, such as opening and closing of valves. SCADA systems can reduce the potential for

* Over-pressure event
* Work procedure errors
* Human performance factors

Points are assigned as follows:

Criteria	Points	Contrib.
No SCADA system exists*	100	10
SCADA in place for entire pipeline system	0	0

* Default

E) **Operational Security Factor** (8% weighting)

Operational Security devices are intended to prevent human error by ensuring that only qualified and knowledgeable personnel have access. Operational security can be a simple device or a complex system. Examples:

* lock-out devices
* key-lock programs
* computer permission requirements

Points are assigned as follows:

Criteria	Points	Contrib.
Operational security does not exist*	100	8
Operational security exists	0	0

* Default

F) **Safety Systems Factor** (5% weighting)

Safety systems are mechanical, electrical, pneumatic, or computer-controlled devices that are applied to prevent pipeline over-pressurization due to human error. Examples: relief valves and switches that close valves or shut down equipment as required.

Points are assigned as follows:

Criteria	Points	Contrib.
No safety systems present*	100	5
Control room monitoring with multiple safety systems in place	0	0

* Default

G) **Procedures** (15% weighting)
Accurate and current technical procedures should be in place and followed by personnel when performing maintenance and inspection on operating equipment. Procedures ensure consistency of personnel qualifications, technology application, results and documentation across an organization. Points are assigned as follows:

Criteria	Points	Contrib.
Effective maintenance procedures are not in place	100	15
Maintenance procedures exist, but inconsistences with implementation are documented*	80	12
Maintenance procedures exist	0	0

* Default

7.0 EQUIPMENT FAILURE THREAT ALGORITHM

Per ASME B31.8S – 2004, "Equipment is defined in this context as pipeline facilities other than pipe and pipe components." An equipment failure is defined as any leak or malfunction attributed to equipment that could affect the safety or reliability of the pipeline. A "leak" is defined as an unintentional escape of gas from the pipeline. A non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak. (Per PHMSA F 7100.1-1 Rev. 01/11)

Possible locations of equipment failures, per ASME B31.8S – 2004, include

- pressure control
- relief equipment
- gaskets
- O-rings
- seal/pump packings

Equipment threats can typically be addressed by examination and evaluation of the specific piece of equipment, component, or pipe joint.

Scoring for the Equipment Failure (E) threat algorithm shall be calculated per the direction of the Equipment Failure Steering Committee. The committee has determined that the factors listed as A through D of this section are significant for determining LOF due to equipment threat. Other factors in risk to transmission and distribution above 60 psig pipeline segments may be considered by the Equipment Failure Steering Committee, based upon newly-available information, and included in the algorithm. These determinations are regularly reviewed and subject to change per RMP-01.

The LOF for E is calculated by:

1. Assigning points to each factor based on maintenance and operating records, assessment results, and pipeline attribute information.
2. Multiplying the assigned points by the weighting for the factor, as established by the Equipment Failure Steering Committee. This product is the contribution for the factor.
3. Summing the factor contributions. This sum is the LOF for E individually.

Before applying the algorithm, the Risk Management Engineer shall evaluate the list of factors and determine whether any factors should be added, removed or modified. Changes to factors, point values, and other aspects of the risk algorithm are performed per RMP-01 and the Management of Change (MOC) process described in RMP-06.

The Risk Management Engineer assigns points to each pipeline segment in accordance with the factor tables below. Points are assigned using all available data including manufacturing and construction records and results of inspections and testing.

Where multiple criteria apply, the criterion with the highest point value is used. The factors for E are as follows:

A) **Regulator Valve Leak/Malfunction (Control Equipment)** (25% weighting)
Regulator valves in the pipeline have the potential to fail and adversely affect the safety and reliability of the pipeline.
Points are assigned as follows:

Criteria	Points	Contrib.
More than one regulator valve leak or failures in the last five years	100	25
One regulator valve leak or failures in the last five years	60	15
No previous leaks or failures*	0	0

* Default

B) **Relief Valve Leak (Relief Equipment)** (12% weighting)
Relief valves in the pipeline have the potential to fail and adversely affect the safety and reliability of the pipeline.
Points are assigned as follows:

Criteria	Points	Contrib.
More than one relief valve leak or failure in the last five years	100	12
One relief valve leak or failure in the last five years	60	7.2
No previous leaks or failures*	0	0

* Default

C) **Gasket or O-Ring Leak** (41% weighting)
Gaskets installed in the pipeline have the potential to fail and adversely affect the safety and reliability of the pipeline.
Points are assigned as follows:

Criteria	Points	Contrib.
More than one gasket leak or failure in the last five years	100	41
One gasket leak or failure in the last five years	60	24.6
No previous leaks or failures*	0	0

* Default

D) **Other Equipment Failure** (22% weighting)
Any piece of equipment attached to the pipeline has the potential to fail and adversely affect the safety and reliability of the pipeline. Examples of other equipment include seals and pump packings.
Points are assigned as follows:

Criteria	Points	Contrib.
More than one leak or failure of other equipment in last five years	100	22
One leak or failure of other equipment in last five years	60	13.2
No previous leaks or failures*	0	0

* Default