PACIFIC GAS AND ELECTRIC COMPANY
GAS TRANSMISSION AND DISTRIBUTION
GAS ENGINEERING
GAS INTEGRITY MANAGEMENT AND TECHNICAL SUPPORT

Risk Management Procedure

Procedure No. RMP-06

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

Rev. No.	Date	Description	Prepared by Integrity Management Program Manager	Approved by Manager, System Integrity		Approved by Director, GSM&TS	Approved by Vice President – Gas Transmission and Distribution, President/CEO Standard Pacific Pipelines, Inc.
0	12/9/04	Initial Issue	[redacted]	[redacted]		[redacted]	[redacted]
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			Prepared by	Approved by	Approved by	Approved by	Approved by
Rev. No.	Date	Description	Integrity Management Program Manager	Manager, Integrity Management	Director Integrity Management and Technical Support	Senior Director, Gas Engineering	Vice President – Gas Transmission and Distribution, President/CEO Standard Pacific Pipelines, Inc
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5		See Change Forms for detailed descriptions					

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List of Illustrations

Introduction

This procedure represents the Gas Transmission Integrity Management Program (IMP) documentation for Pacific Gas and Electric Co and Stanpac Inc, herein referred to as "Company." This procedure has been designed to provide the best methods and implementation to ensure the safety of gas transmission pipelines located where a leak or rupture could do the most harm. This procedure is the controlling document for the Gas Transmission Integrity Management Program (IMP). Unless otherwise noted herein, where there are conflicts between this procedure and other procedures or instructions for this program, this procedure shall take precedence.

Corporate Philosophy

"To deliver services at the lowest possible cost without compromising safety or environmental compliance"

Integrity Management Program Ownership

The Integrity Management (IM) Program (RMP-6) shall be the responsibility of the Manager of Integrity Management and Technical Support. Minor changes to the program can be implemented upon the authorization of the Manager by a signed exception report or a revision to this procedure. However, a new version of the program shall be issued as necessary and approved by the Manager of Integrity Management, the Director of Integrity Management and Technical Support, the Senior Director of Gas Engineering, and the Vice-President of Gas Transmission and Distribution and the President/CEO of Standard Pacific Gas Line Inc. This process will ensure continued awareness and commitment to the Integrity Management Program. The signing authority for other Risk Management Procedures (RMP's) shall be noted in those documents but are normally approved by the Manager of Integrity Management. Risk Management Instructions (RMI's) are meant to supplement procedures and to provide more detailed guidance on one method of meeting procedural requirements. RMI's are normally approved by the Integrity Management Program Manager. Exceptions are those RMI's intended for widespread company use. Those RMI's shall be approved by the Manager of Integrity Management. RMI's are not meant to document the only acceptable method of meeting procedural requirements nor do they supersede procedural requirements.

Covered Facilities

This Transmission IM Program is applicable to all gas transmission lines operated by the Company. It does NOT apply to those facilities that are used for gas gathering or gas distribution.

All of company pipelines operating over 60 psig are steel, however not all of them meet 49 CFR Sect 192.3's definition of a transmission line. The Company's interpretation of this definition was used to review all pipelines operating over 60 psig and determine which pipelines are covered by the rule. This delineation was noted in GIS by using the Transmission Definition (TRANSDEF) field in the Transmission Main layer. For details of Transmission Definition refer to Appendix A.

Organization of IM Program

This program documentation is divided into elements applicable to each of the requirements as stated in Section 192.911 of the Subpart O-Pipeline Integrity Management. Each element is supported by documentation of the general process(es) used by the Company to comply with the requirements of that element. Procedures that give specifics of how each step of the process is conducted are provided, either as appendices or via a reference or link given to access documentation that is separate from this plan.

This IM Program is meant to provide a framework for the Company's program for integrity management, but does not repeat every element of the program that is already in place or is described by procedures with existing, readily available documentation. Where the Company has previously established and documented procedures for any part of

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the element, this is stated and the location of that documentation is noted. A listing of these documents as referenced throughout this IMP is presented in each Section as applicable

Correlation with Other Company Programs

This document shows how new programs are integrated with established Company programs to address the Integrity Management Program. Among these Company programs are:

- Gas Transmission Risk Management Program
- Public Safety Information Program (PSIP)
- First Responder Training
- Gas Transmission Facility Geographic Information System (GIS)
- Enterprise Risk Management (ERM)

Use of Industry References

Several industry regulations and standards are referenced continually throughout this document. The table below lists these references and the acronym or shortened notation used to designate that reference.

Complete Reference	Listed as:	Notes:
CFR Part 192 Subpart O Sections 192.901 through Appendix E	Section or Appendix number e.g. 192.903 (1) or 192 Appendix E	Where only a section or appendix number is given, it shall be presumed that this references Subpart O
ASME/ANSI B31.8S-2004	B31.8S	Particular sections follow the general designation i.e. B31.8S 4.4
NACE RP 0502-2002	NACE RP 0502	Particular sections follow the general designation i.e. RP-0502 5.5

Training and Qualification Requirements

The provisions of this procedure shall be applied under the direction of competent persons who, by reason of knowledge of the integrity management program in the pipeline industry are qualified to review Risk and Threat Analysis on transmission piping systems. The specific qualifications are described below.

Manager of Integrity Management: Shall be a degreed engineer and have gas transmission pipeline experience to provide oversight to personnel conducting Integrity Management Program process. Training: 1. Review RMP-06 and BAP during approval process: NACE CP1 and RSTRENG training are desired.

Integrity Management Program Manager (IMPM): The Supervising Engineer of Risk Management shall be the IMPM. The IMPM shall be a licensed and degreed engineer with a minimum of 5 years of experience (or equivalent) performing integrity management in the pipeline industry. The IMPM shall document who the Sr. Risk Management Engineer, Risk Management Engineer , and Gas Transmission Pipeline Public Awareness Program Manager are. Training: 1.Review of RMP-06 each calendar year, NACE CP1 & 2 and RSTRENG training are desired.

Sr. Risk Management Engineer (SRME): The SRME shall be a degreed engineer with experience performing integrity management in the pipeline industry.
Training: 1. Review of RMP- 06 each calendar year, NACE CP1 & 2 and RSTRENG training are desired.

Risk Management Engineer (RME): The RME shall be a degreed engineer with experience performing integrity management in the pipeline industry.
Training: 1. Review of RMP- 06 each calendar year, NACE CP1 and RTSTRENG training are desired.

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Qualifications and Training Requirements of other Groups supporting the Risk Management Program:

Gas Transmission Public Awareness Program Manager (PPAPM): The PPAPM shall have experience with PG&E's third party public communications and awareness training, and land owner notification program.
Training: 1. Review RMP-06, Sec. 9 as there are revisions.

Corrosion Engineer (CE): The Corrosion Engineer is the Senior Advising Corrosion Engineer and shall be a degreed engineer with experience with corrosion control in the pipeline industry.
Training: 1.Review of RMP-06 as there are revisions, 2. RSTRENG Training Course, 3. PG&E Gas Transmission Corrosion Control Training Course. NACE CP-1, NACE CP2 and NACE CP3 are desired.

GIS Team Lead: Shall be the program lead for the GIS program.
Training: RMP-06, Sec. 2 as there are revisions.

Pipeline Engineers: Shall be a degreed engineer with transmission pipeline experience.
Training: RMP-06, Sec. 2 as there are revisions.

Estimating and Mapping Supervisor: Shall understand the ESC mapper's process for updating as built drawings into the GIS program.
Training: RMP-06, Sec. 12 as there are revisions.

Mappers: Shall be an ESC mapper with GIS program experience
Training: RMP-06, Sec. 2 as there are revisions.

Director of Integrity Management and Technical Support:
Training: Review of RMP-06 during approval process.

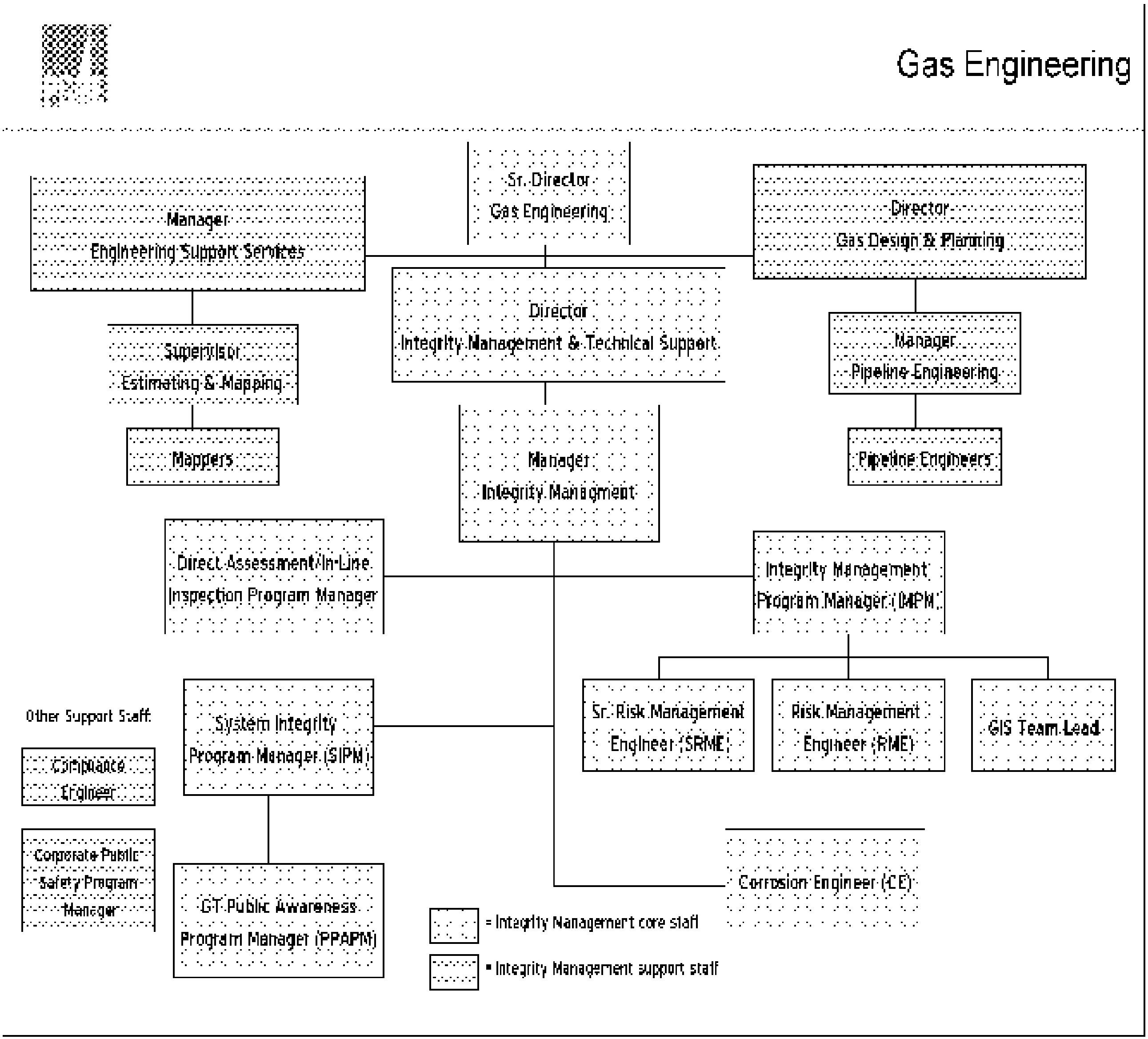
Senior Director of Gas Engineering: Shall have authorization to approve BAP.
Training: Review of RMP-06 during approval process.

In-Line Inspection /Direct Assessment Program Manager: Qualifications listed in RMP-09 and RMP-11
Training: RMP-06, Sec. 5, 10, 12, 14 as there are revisions.

Compliance Engineer: Shall have experience with Internal Audits.
Training: RMP-06, Sec. 10 as there are revisions.

SAFETY HEALTH AND CLAIMS DEPARTMENT
Corporate Public Safety Program Manager: Shall have experience in the company's safety program and knowledgeable with the public safety information program.
Training: RMP-06, Sec. 9

Program Organization Chart



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1. HCA Identification

1.1. Scope
192.903

The integrity management regulation was designed to address areas of a pipeline that are located in high consequence areas (HCAs). HCAs are areas where a leak or failure could have a serious effect on populations. This section describes the HCA identification process for Company pipelines.

1.2. Background

Chosen Method for HCA Identification

In order to effectively manage risk, pipeline segments located within high consequence areas (HCAs) must first be identified. HCAs can be identified using two methods. Either method or a combination of both may be used. At present, the Company has chosen to use Method 2 as defined in 49 CFR Part 192.903 (2).

192.903 (2)

Method 2: The area within a potential impact circle (PIC) containing

- An identified (Id) site or
- 20 or more buildings intended for human occupancy

Identified Sites

192.903 (b)

See RMP-08 for more information on Identified Sites.

192.903 (2)
192.903 (a)

The Company has chosen to identify its HCAs according to **Method 2**. The Company's Pipeline layer in its GIS contains an HCA_ID field starting with one of five alpha characters designating that HCA analysis has been performed on the transmission pipeline segment and the result of the analysis. The alpha characters are A, B, I, N, and Z are summarized below. Refer to RMP-08 for detailed definitions.

A HCA due to 20 or more structures within the PIC
B HCA due to both identified sites and 20 or more structures within the PIC
I HCA due to identified site within the PIC
N Non-HCA
Z – Non-HCA confirmed after closer visual examination by another engineer

1.3. Processes for HCA Identification

192.905

The Company uses the procedure specified in RMP-08 "Identification, Location, and Documentation of High Consequence Areas (HCAs)" to identify those segments of its pipelines that are located in HCAs. PG&E Gas contains less than 1100 BTU per standard cubic foot. (Note: Consideration shall be given in the HCA identification process where BTU values exceed 1100 BTU per standard cubic foot). A general summary of the process follows below. The details of the process may vary slightly from year to year and is documented in RMP-08, RMI-01, RMI-05 and/or the county specific report prepared to document the HCA review for that county. See below for a summary of the HCA identification process:

1. For a complete county review, where available, review land use for parcels in transmission line PIC's plus a buffer of 100 feet and identify:
   - Identified sites
   - Care facilities
   - Other occupied structures
2. Visually review the parcels with unclear or unknown land use and designate the structures for the presence of an Id Site. If a visual review is not performed on an uncoded/unclear/unknown parcel, assume it is an identified site.
3. An optional process to identify HCA's is to utilize GIS HCA script to perform HCA analysis of transmission pipeline segments.
4. For counties where parcel data is considered by the reviewer to be very poor, a visual review of the pipeline without regard to land use codes is acceptable.
5. Visually review all transmission lines to validate the GIS analysis and document the exact extent of the required assessment. Document the extent and type of HCA in the Pipeline layer.
6. Quality Assurance is required by a second engineer if in the judgment of the reviewing engineer, there is some uncertainty over whether the site is not an HCA and the engineer feels that a second engineer's review would be prudent. This occurs most frequently when the original analysis designates the area and HCA (based on the GIS script) and subsequent visual analysis shows it is a non HCA.
7. Post updates to Pipeline layer.
8. Complete county reviews looking for new HCA's are required only once every five years. Reviews in other years shall at a minimum consist of reviewing changes to country parcel data land use codes and care facilities (where available).
9. For stations, the company also uses the procedure specified in RMP-08 "Identification, Location, and Documentation of High consequence Areas (HCAs)" and RMI-05 to identify those segments that are located in HCAs

[redacted]

192.905 (c)

Newly Identified Areas

When information for an area not previously classified as an HCA is received that indicates a change in conditions, this area shall be examined using Method 2 as described above. This information could be received from various sources. The most likely sources include:

- Annual parcel and tax roll data updates
- New licensed care facility in Ca. Social Services Licensed Community Care Listing
- Field reports
- Change in Class location
- Surveillance and patrolling
- Meetings with First Responder personnel (every two years)
- New and uprated pipelines
- Realigned pipelines

Once an area is identified as a new HCA, it shall be incorporated into the Baseline Assessment Plan (Section 4) no later than one year from the date of identification using the procedures outlined in Section 2 of this plan. For additional information on the incorporation of new HCAs, see Section 17 "New HCA Identification" of this plan. The method to address piping changes that could affect HCA extents is described in section 12.

Removal of HCAs

In addition to supplying information about a potentially new HCA, field reports and field verification could also potentially remove an HCA. If an HCA whose status can not be annually re-verified using parcel data or aerial photographs, it shall be entered into the Site Review Log for follow-up to verify that it remains not an HCA.

1.4. Procedures and Instructions

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-08	Identification, Location, and Documentation of HCAs	As needed	RM File 7.8
RMP-12	Pipeline Public Awareness Plan	As needed	RM File 7.12
RMI-01	HCA Identification in Support of Annual Systemwide Risk Calculations	As needed	RM File 7.6.1
RMI-05	Station HCA Identification	As needed	RM File 7.6.1
WP 4125-04	Uprate Procedure	As needed	Technical Library

1.5. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Cadastra parcel data review – letter to RM File	RM File 7.8
Michael Baker parcel data review – letter to RM File	RM File 7.8

[redacted]

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Landuse code designations for each county	RM file 15
Letter to file for organizational explanation	RM File 7.8
Site Review Log	RM File 7.8
Letters to file on BTU of gas content	RM File 7.8

1.6. Roles and Responsibility

Summary of the responsibilities for ensuring compliance with the element covered by this Section are as follows (more detail is contained in RMP-08):

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager of Integrity Management	Implementation of RMP-08
Risk Mgmt Engineers	Integrity Management Program Manager	Parcel data review and assessment of HCA extents
Public Awareness Program Manager	Supervisor Gas System Integrity	Every two years, identified site review with First Responder personnel

1.7. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
RMP-08	Review each calendar year and update as necessary
Parcel and tax roll updates/changes	Once each Calendar Year
Licensed Community Care listing	Once each Calendar Year
New HCA assessments	Once each Calendar Year
First Responder Meetings	Every two years

2. Threat Identification: Data Integration

2.1. Scope

Potential threats to an HCA must be identified and then evaluated through a comprehensive risk analysis process. This section provides information on collecting the data that is needed to perform effective assessments.

2.2. Background

192.917

B31.8S 2.2

There are a minimum of 21 causes of gas pipeline incidents identified by the integrity management regulations and B31.8S, these are placed into nine categories, plus the category of "unknown".

Time-Dependent	1	External Corrosion	1	External Corrosion
	2	Internal Corrosion	2	Internal Corrosion
	3	Stress Corrosion Cracking	3	Stress Corrosion Cracking
Stable	4	Manufacturing Related Defects	4	Defective pipe seam
			5	Defective pipe
	5	Welding/Fabrication Related	6	Defective pipe girth weld
			7	Defective fabrication weld
			8	Wrinkle bend or buckle
	6	Equipment	9	Stripped threads/broken pipe/coupling failure
			10	Gasket O-ring failure
			11	Control/Relief equipment malfunction
			12	Seal/pump packing failure
			13	Miscellaneous
Time-Independent (includes Human Error)	7	Third Party/Mechanical Damage	14	Damage inflicted by first, second, or third parties (instantaneous/immediate failure)
			15	Previously damaged pipe (delayed failure mode)
			16	Vandalism
	8	Incorrect Operations	17	Incorrect operational procedure
	9	Weather Related and Outside Force	18	Cold weather
			19	Lightning
			20	Heavy rains or floods
			21	Earth Movements
Unknown		Unknown	22	Unknown

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Since more than one threat can occur on a section of pipe, each HCA must be examined to ascertain which of these threats possibly present an element of risk to that HCA. This Section covers the process by which data is assembled for HCAs.

Section 3 "Threat Identification: Risk Assessment" discusses the method by which the HCAs are examined for each risk factor to best determine the driving risk factors for that HCA.

2.3. Company Compliance

To ensure that the risk assessment and threat identification remains current, it is Company policy to perform risk assessment (per procedure RMP-01) for all transmission pipelines on an annual basis and threat analysis for all HCAs also on an annual basis. Procedure RMP-01 (Risk Management) and supporting procedures RMP-02 (External Corrosion Threat Algorithm), RMP-03 (Third Party Threat Algorithm), RMP-04 (Ground Movement Threat Algorithm), and RMP-05 (Design/Materials Threat Algorithm) provide the requirements for determining the relative risk ranking of all of the Company's transmission pipelines and serve as a basis for this procedure's description of data integration into the threat identification for HCAs.

The overall process by which the Company has chosen to comply with these requirements consists of the following steps:

1. Gather data
2. Review data
3. Integrate data to understand the condition of the pipe
4. Perform risk analysis
5. Identify the location-specific threats that could affect each HCA based on the nine categories as identified in Section 2.2 of B31.8S
   - External Corrosion Threat
   - Internal Corrosion Threat
   - Stress Corrosion Cracking Threat
   - Manufacturing Threat
   - Construction Threat
   - Equipment Threat
   - Third Party Threat
   - Incorrect Operations Threat
   - Weather and Outside Force Threat

This process is illustrated by the following flowchart.

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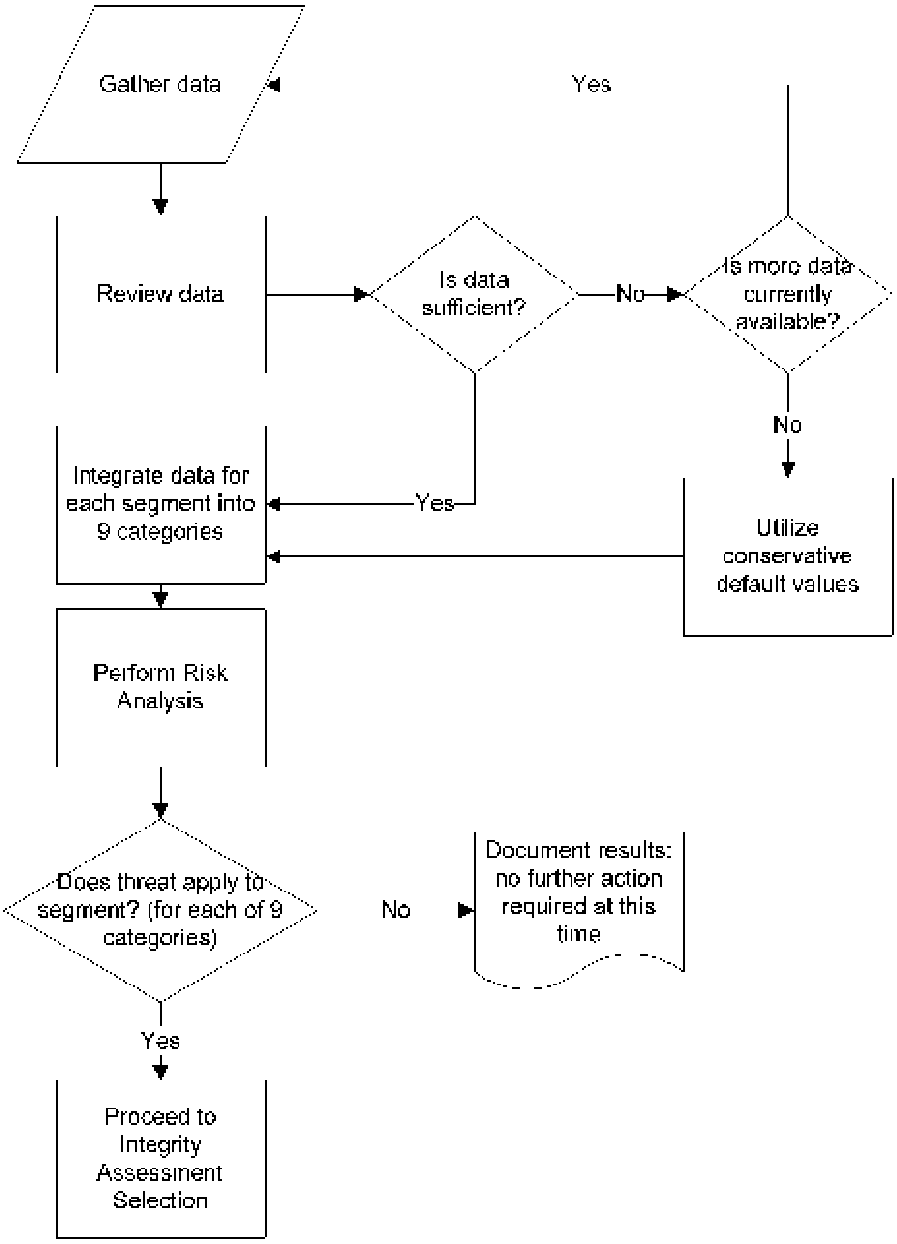
Threat Identification and Risk Analysis Process Flowchart



2.4. Gather Data

Comprehensive pipeline and facility knowledge are essential to understanding the risk drivers that can affect an HCA. No one source of information is sufficient to make a reasonable assessment of risk; therefore, this information is gathered from numerous sources and has been integrated into the Company's GIS system.

B31.8S 4

Typical Data Elements

B31.8S Appendix A

The typical data elements used in threat identification (Excluding the Equipment Threat, which is covered by a separate procedure) are shown in Appendix B of this procedure, and are documented, per HCA, in the Baseline Assessment Plan, and in the HCA Risk Calculation and Threat Analysis.

The process used for risk analysis can be found in Procedure RMP-01 (Risk Management) and supporting procedures RMP-02 (External Corrosion Threat Algorithm), RMP-03 (Third Party Threat Algorithm), RMP-04 (Ground Movement Threat Algorithm), and RMP-05 (Design/Materials Threat Algorithm). The data used for the risk assessment for each HCA is contained in the Risk Calculations for a given year (documented in the Risk and Threat spreadsheet(s)) and is summarized in Baseline Assessment Plan (see section 4.3).

Data Sources

B31.8S 4.3

Data used in threat identification 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 INGAA/AGA Vintage Pipeline report, USGS and OPS

Table 2 of B31.8S lists many of these sources. Additional sources, both internal and external, are also referenced in both the integrity management regulation and B31.8S. The B31.8S sources utilized by the Company and the additional Company-specific sources, are presented in the following table:

[redacted]

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Typical Data Sources		
	B31.8S Table 2	**Additional**
Internal	Pipeline alignment drawings	Existing Management Information System (MIS) databases Geographical Information System (GIS) databases Results of prior risk or threat assessments
	Pipeline aerial photography Facility drawings/maps As-built drawings	Subject Matter Experts (SMEs) Root cause analyses of prior failures Inspection, examination and evaluation data from integrity management implementation Operating History Current Mitigation activities
		Process and Procedure Reviews
	Operator standards/specifications Industry standards/specifications	Maintenance Records Patrol Reports
	Inspection records Test reports/records Incident reports	GIS A forms GIS H forms GIS Pipeline data Gas Transmission Incident Reports
	Manufacturer equipment data	

[redacted]

Typical Data Sources		
	B31.8S Table 2	Additional
External		Jurisdictional agency reports and databases including: Ground Acceleration Fault Crossings Slope Stability Liquefaction Potential Hydrology Levee Crossings Soil Resistivity
	First Responder Input	Marked up pipeline maps showing HCA's
		Pipeline Association for Public Awareness (PAPA) response to PG&E outreach

Data Elements Selected for Initial Analysis

For the risk analysis process, the Company has chosen pipeline attributes based upon available, verifiable information or information that can be obtained in a timely manner. The data elements used in the initial analysis are identified in Procedure RMP-01 (Risk Management) and supporting procedures RMP-02 (External Corrosion Threat Algorithm), RMP-03 (Third Party Threat Algorithm), RMP-04 (Ground Movement Threat Algorithm), and RMP-05 (Design/Materials Threat Algorithm). Documentation of each data element used in the HCA Risk Calculation and the manner in which it was incorporated into the algorithms shall be developed, signed by the Risk Management Engineer, approved by the Manager of Integrity Management, and retained in the Risk Management Files. Metadata for the source of each input type shall also be developed and retained in Risk Management Files for each annual HCA Risk Calculation.

Data for Future Analyses

Data integration for integrity management is an ongoing process. After the initial risk analysis and threat identification is made, re-analysis will be made on an annual basis. New or revised information regarding new pipe segments, pipe properties, pipe location, inspection information, and assessment information shall be incorporated into GIS on an on-going basis. This information will be integrated annually into the HCA Risk Calculation. New or revised information regarding environmental conditions surrounding the pipe such as ground acceleration, land base information, faults, slope stability, liquefaction, parcel data, high consequence structures etc. shall be updated as it becomes available, but at a minimum reviewed at intervals specified in Procedure RMP-01.

2.5 Review Data

B31.8S 4.3

The quality and consistency of the data must be verified once information is collected. The following issues shall be considered as data is reviewed for impact on the analysis results.

- Data resolution and units: consistency in units must be maintained
- Common Reference System: allows data elements from various sources to be combined and accurately associated with common pipeline locations
- When possible, utilize all actual data for an HCA
- Age of data: this is especially important to time-dependent threats

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Insufficient Data or Poor Quality Data

This Program avoids the use of data assumptions to identify applicable threats. Missing data elements are evaluated to determine the significance of their impact to the threat analysis and any necessary default values are conservatively applied. The data for each HCA is documented in GIS, the BAP, the LTIMP, the Risk and Threat Spreadsheet or project files.

2.6. Integrate Data

The data elements that have been gathered from the various sources shall be integrated into GIS and a theme shall be created for use in calculating the overall risk of each HCA. Documentation of the manner in which the information was queried from GIS for linking to the appropriate HCA shall be developed and retained in Risk Management Files for each annual HCA Risk Calculation. Appendix B details the data elements used for each HCA's risk and threat analysis.

2.7. Data Configuration

The Company currently uses the following methods for data integration:

- Pipe properties (size, specification, location, inspection data, and assessment data) are updated on an ongoing basis by the Mapping Department and are stored in GIS.
- Environment Data (ground movement attributes, proximity of identified sites, proximity of land features, etc) shall be stored in GIS and shall be updated by the Integrity Management Program Manager as new information becomes available. At a minimum it is reviewed per the requirements of Procedure RMP-01.
- Data used to perform risk calculations (a result of GIS queries of applicable themes) shall be retained with the HCA Risk Calculations. This is currently in the, the Risk and Threat Spreadsheet.

2.8. Management of Change

The Company's Management of Change process ensures that all changes to the pipeline are fully documented and tracked. This is accomplished by updating GIS on an on-going basis with new pipeline segments, incorporating relevant changes to existing pipeline information, updating environmental conditions surrounding the pipe at intervals specified in RMP-01, and recalculating risk and threat analysis annually to incorporate the changes. See Section 12 Management of Change for a description of this process.

2.9. Procedures and Instructions

This subsection contains a list of the procedures, instructions and/or other documentation used to comply with this element of the integrity management regulations

Title	Description	Update Schedule	Location
RMP-01 – Risk Management	Provides requirements for the Risk Management process, update requirements for data not updated on an on-going basis by the Mapping Department, and data elements used for determining the Consequence of Failure (COF).	Reviewed each calendar year and updated as necessary.	RM File-7.1
RMP-02 External Corrosion Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to External Corrosion (LEC) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File7.2

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RMP-03 Third Party Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Third Party (LTP) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File 7.3
RMP-04 Ground Movement Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Ground Movement (LGM) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File 7.4
RMP-05 Design/Materials Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Design and Materials algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File 7.5
RMI-02 GIS Data Queries in Support of Systemwide Risk Calculations	Provides one detailed method of performing data queries for systemwide risk calculations	As needed	RM file 7.6.1

2.10. Supporting Documents The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
HCA Risk Calculations	\\Walnuterk01\Mapping\RiskMgmt\Integrity Managment Plans\Threat Analysis*VARIOUS FOLDERS and file names*
Risk Calculation Key/Process	\\Walnuterk01\Mapping\RiskMgmt\Integrity Managment Plans\Threat Analysis*Risk Speadsheet Key.xls*
Threat Analysis	\\Walnuterk01\Mapping\RiskMgmt\Integrity Managment Plans\Threat Analysis*VARIOUS FOLDERS and file names*
GIS Manual	\\Walnuterk01\Mapping\ RiskMgmt\Procedures\Mapper Manual (revise GSAVE man).doc

2.11. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Manager of Integrity Management	Director of Integrity Management and Technical Support	Responsible for Integrity Management Program. Reviews and approves all Integrity Management and Risk Management Procedures
Integrity Management Program Manager	Manager of Integrity Management	Responsible for Risk Management Program (RMP-01, RMP-02, RMP-03, RMP-04, and RMP-05), GIS data quality and data integration, Metadata on data sources, threat identification, assessment selection (this procedure), obtaining and updating GIS to reflect HCA's from outside commercial and jurisdictional databases. Responsible for reviewing and approving Risk Management Procedures, and Integrity Management Program Procedure. Reviews and approves Risk Management Instructions.
Mapping & Records Supervisor	Design and Estimating Supervising Engineer	Responsible for maintaining accurate and current pipeline information in GIS.
Mappers	Mapping & Records Supervisor	Responsible for maintaining GIS as a current record of its pipeline facilities. Maintenance is performed by utilizing records from various sources including; Construction "As-Builts", Inspection and Leak reports, "New Construction along Pipeline" reports, and continually aligning facilities to GPS reads taken by field personnel
GIS Team Lead	Supervisor of Risk Analysis	GIS Program Development and Maintenance
Public Awareness Program Manager	Supervisor of Gas System Integrity	Have GIS updated to reflect HCA's identified by Public Safety Officials, Third Party Dig-In concerns identified by the districts, and Public Education Efforts to reduce the likelihood of Third Party damage.
Pipeline Engineers	Manager, Pipeline Engineering	Submit notification of landslide or erosion concerns.

2.12. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Threat identification	Once each Calendar Year

[redacted] GTR0003401

3. Threat Identification: Risk Assessment

3.1. Scope

Potential threats to an HCA must be identified and then evaluated through a comprehensive risk analysis process. This Section covers the process by which HCAs are examined for each threat to best determine the driving risk factors.

3.2. Background

There are a minimum of 21 causes of gas pipeline incidents identified by integrity management regulations and B31.8S, which are placed into nine categories plus the category of "unknown." See Section 2 Threat Identification: Data Integration for a description of these threats and the data elements selected to perform the initial risk analysis and threat identification.

Since more than one threat can occur on a section of pipe, each HCA must be examined to ascertain which of these threats possibly present an element of risk.

3.3. Risk Assessment

192.917 (c)

Risk assessment is performed per RMP-01. The RMP-01 methodology looks at all threats for which meaningful data is available. Including threats where meaningful data is not available will mask the significance of those threats which can be more precisely defined. As better data becomes available for threats not currently included in RMP-01, that procedure will be updated to include them. This risk assessment provides a method to prioritize HCAs for the baseline assessment schedule as well as providing the information needed for effective preventive and mitigative actions. Assessment also helps determine modified inspection intervals for continued re-assessments and whether or not alternative inspection methods are needed.

Risk assessment provides a rational and consistent method to make determinations about the integrity of a pipeline segment and allows more effective use of resources in both identifying and mitigating threats. Effective data integration combined with assessment identifies the scenarios more likely to occur and prevents focusing on improbable catastrophic events.

3.4. Risk Definition and Computations

Risk can be described as the product of "likelihood" and "consequence". Risk Analysis is performed per procedure RMP-01 for all transmission pipelines. The method described in the procedure is a relative risk ranking approach with Subject Matter Experts providing input and direction as to the algorithms used to perform the computations.

Steering Committees have been established and meet each calendar year to review the algorithms and consider changes to improve the accuracy of the algorithm results. The membership and minutes from the meetings are documented in the Risk Mgmt Library, File 4.0. The established Steering Committees include;

- Consequence Steering Committee with oversight of RMP-01 (Risk Management),
- External Corrosion Steering Committee with oversight of RMP-02 (External Corrosion Threat Algorithm),
- Third Party Steering Committee with oversight of RMP-03 (Third Party Threat Algorithm),
- Ground Movement Steering Committee with oversight of RMP-04 (Ground Movement Threat Algorithm), and
- Design/Materials Steering Committee with oversight of RMP-05 (Design/Materials Threat Algorithm)

3.5. Threat Analysis

Threat Analysis shall be performed for all covered pipeline segments integrating information from Risk Analysis for both covered and non-covered pipeline segments as follows

External Corrosion: The External Corrosion Threat was assumed to exist on all gas transmission pipelines. Information integrated into the risk calculations required to comply with RMP-02 and used to weight the relative significance of the threat include:

- Past Corrosion Surveys,
- Visual Inspection of Coating,
- Presence of Casings,
- Past ILI,
- EC Leak Experience,
- Coating Type,
- AC/DC Interference,
- Coating Age,
- MOP vs. Pipe Strength,
- Visual Inspections of Pipe,
- Pressure Testing, and
- Past ECDA (External Corrosion Direct Assessment). Also included, to meet these requirements, is pipe Outside Diameter, Wall Thickness, MOP.
- Soil Resistivity
-

Inspection data and leak experience on adjacent pipeline segments, whether HCA or not, shall be considered in the quantification of Likelihood Of Failure (LOF) due to external corrosion per the requirements of RMP-02.

Internal Corrosion: Internal Corrosion threat is known to exist if an internal corrosion leak has occurred in the vicinity of the HCA or if in the threat exists in the judgment of the Senior Corrosion Engineer. The Senior Corrosion Engineer shall perform this system-wide analysis and specify where the threat is known to exist

Internal corrosion is a possible threat for the remaining pipeline so additional data integration will occur during the pre-assessment and direct examination phases of ECDA, in order to determine if the threat exists. The additional data integration includes:

- During pre-assessment, historical records, operating history and the experience of field personnel will be researched. If pre-assessment reveals the potential for internal corrosion, ICDA will be performed to assess the HCAs affected.
- During direct examinations, ultrasonic wall thickness reads will be taken at the bottom of the pipe, if internal corrosion is discovered ICDA will be performed to assess the affected HCAs.

Stress Corrosion Cracking: The Stress Corrosion Cracking (SCC) Threat shall be assumed to exist if SCC has been experienced (determined by a leak, Pressure Test Failure, or inspection) on any pipeline segment with similar pipe properties and operating conditions or if all of the following conditions are present:

- Operating stress > 60% SMYS
- Distance from (downstream) of a compressor station < 20 miles
- Coating system other than fusion bonded epoxy (FBE)

Manufacturing Threat: The Manufacturing Threat shall be assumed to exist if the HCA meets one of the two following criteria.

1. If the pipe segment is a) Cast Iron, b) installed before 1970, c) joined with acetylene welds, d) joined with mechanical couplings, or
2. If the pipe segment has a Joint Efficiency Factor of less than 1.0 or is manufactured with Low Frequency ERW or Flash Welded Pipe (assumed to be pipe installed with ERW, Flash Weld, or Unknown Seam prior to 1970).

Construction Threat: Due to the concern for potentially non-ductile girth welds, it shall be assumed that the Construction Threat exists for all HCAs installed prior to 1947. In addition, pipelines with wrinkle bends shall be assumed that the Construction Threat exists.

Equipment Threat: This threat could result from a failure of equipment at any point in the system and is assumed to exist for all HCAs. It is addressed through the Company's maintenance and operations procedures.

Third Party Threat: The Third Party Threat shall be assumed to exist for all HCAs. Information integrated into the risk calculations documented in RMP-03 and used to weight the relative significance of the threat include:

- Feedback regarding pipelines particularly vulnerable to dig-ins
- Class Location
- Damage Prevention Measures (Standby/Aerial Patrol/None)
- Ground Cover (from inspection reports and GIS)
- Pipe Diameter
- Wall Thickness
- Line Marking
- MOP vs. Pipe Strength
- Third Party Leak History
- Public Education efforts in the area.

It should be noted that, inspection data and leak experience on adjacent segments, HCA or not, shall be considered in the quantification of Likelihood Of Failure (LOF) due to a third party.

[redacted]

Incorrect Operations Threat: The Incorrect Operations Threat was assumed to exist for all HCAs.

Weather and Outside Forces Threat: The Weather and Outside Forces Threat shall be assumed to exist if HCA meets any of the following criteria:

- Is in an area of potential ground acceleration greater than 0.2g
- Crosses a Historic or Holocene Earthquake Fault
- Crosses a navigable waterway
- Erosion has been identified
- Landslide has been identified
- Is in an area of High/Moderate or known Slope Instability
- Is in an area of Known or High/Moderate potential for liquefaction in combination with ground accelerations equal to or greater than 0.2g.
- **Levee crossings susceptible to erosion failure**

Hard Spot : The Hard Spot shall be assumed to exist if the HCA meets the following criteria:

- Operates at a stress greater than 50% SMYS (based on MOP) and has one of the following seam types:
  - Unknown seam type installed between 1947 and 1960,
  - Flash Welds from AO Smith or unknown manufacturer installed between 1952 and 1957,
  - DSAW Welds from Bethlehem, Kaiser, Republic or unknown manufacturer installed between 1949 and 1957,
  - ERW Welds from Youngstown Sheet and Tube or unknown manufacturer installed between 1947 and 1960.
  - Hard spots are not a recognized threat in 49CFR192 subpart O. The extent of PG&E's supplementary assessments or mitigations for this threat will vary from location to location and completion of an assessment or mitigation of this threat is not necessary to declare the pipeline assessment completed. Where identified, the primary mitigation will be through limiting the amount of cathodic protection to a pipe to soil potential of less than 1200 millivolts. The hard spot also shall be included in the risk algorithum.

Documentation: Results of the Threat Analysis and relevant data for each HCA shall be included in the BAP.

[redacted]

3.6. Procedures

This subsection contains a list of the procedures, instructions, and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-01 – Risk Management	Provides requirements for the Risk Management process, update requirements for data not updated on an on-going basis by the Mapping Department, and data elements used for determining the Consequence of Failure (COF).	Reviewed each calendar year and updated as necessary.	RM File-7.1
RMP-02 External Corrosion Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to External Corrosion (LEC) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File-7.1
RMP-03 Third Party Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Third Party (LTP) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File-7.2
RMP-04 Ground Movement Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Ground Movement (LGM) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File-7.3
RMP-05 Design/Materials Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to the Design/Materials threat algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File-7.4
RMI-03 Annual Systemwide Risk Calculations and IM Threat Analysis	Provides one detailed method for performing annual systemwide risk calculations	As needed	RM file 7.6.1

3.7. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
HCA Risk Calculations	\\Walnutcrk01\Mapping\RiskMgmt\Integrity Management Plans\Threat Analysis*VARIOUS LOCATIONS AND FILE NAMES*
Risk Calculation Key	\\Walnutcrk01\Mapping RiskMgmt\Integrity Managment Plans\Threat Analysis\VARIOUS LOCATIONS AND FILE

	NAMES
Threat Analysis	\\Walnutcrk01\Mapping\RiskMgmt\Integrity Managment Plans\Threat Analysis\VARIOUS LOCATIONS AND FILE NAMES

3.8. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Manager of Integrity Management	Director of Integrity Management and Technical Support	Responsible for Gas Transmission Integrity Management Program. Reviews and approves all Gas Transmission Integrity Management and Risk Management Procedures
Integrity Management Program Manager	Manager of Integrity Management	Responsible for Gas Transmission Risk Management Program (RMP-01, RMP-02, RMP-03, RMP-04, RMP-05, and this procedure), GIS data quality and data integration, Metadata on data sources, Supervises Threat Identification and Risk Analysis, Assessment Selection (this procedure). Responsible for reviewing and approving Risk Management Procedures, and Integrity Management Program Procedure.
Sr. Risk Management Engineer/Risk Management Engineer	Integrity Management Program Manager	Perform Risk Computations and Threat Analysis per procedure. Report results.

3.9. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Risk Calculations	Annually

[redacted] GTR0003407

4. Baseline Assessment Plan

4.1. Scope

192.921(d)

A Baseline Assessment Plan (BAP) provides the planned schedule for the assessment of all HCAs. This Section outlines the process and requirements for scheduling these assessments and updating the BAP.

4.2. Background

Those HCAs with the highest potential for risk are given priority. At least 50 percent of the HCAs identified in the first issue of the BAP must be completed by December 17, 2007 and the remainder from that first BAP must be completed by December 17, 2012. Reassessment dates will be assigned in accordance with Section 7 of this procedure.

[illegible]

In addition, operators must have started the initial assessment by June 17, 2004.

192.921(f)

The Baseline Assessment on newly identified HCAs must be completed within 10 years from the date the area is identified. Section 17 of this manual addresses new area identification.

[redacted]

192.919 The Baseline Assessment Plan required by CPUC GO 112 and the 49CFR192 is documented through the Company's approved BAP with annual revisions. The Integrity Management Assessment Computer System (IMACS), Assessment Mileage Table, and GIS will be used to help track the requirements of the BAP. In some cases, IMACS and GIS will be updated in advance of changes to the BAP.

The approved BAP list is a signed and approved listing containing the following:

- HCAs identified by pipeline, segment number, starting and ending mile points
- Segments requiring assessment by the California State Lands Commission. They shall be designated with the suffix L on the Trans Def code (e.g. TL, TIL, TCL, DL, etc…).
- Type of HCA: A – 20 or more structures, I – Identified site, B – Combination
- Risk assessed for each HCA
- Threats identified for each HCA
- Planned assessment method for external/internal corrosion (Direct Assessment(E) or In Line Inspection (I)or Pressure Test(P)). Stress Corrosion Cracking shall be assessed using SCCDA.
- When next assessment is planned
- When the last assessment was done

The approved BAP list is located in the RM File 7.6 as a supplement to this procedure. An updated BAP shall be issued once each year and be updated to reflect the current assessment schedule. The actual assessment date may be later than the planned date in the BAP provided other scheduling requirements are met (i.e. all segments from the intial BAP are assessed by 12/17/12, all new HCA segments are assessed within 10 years of identification, and maximum reassessment intervals as required by subpart O and this procedure are not exceeded).

Risk management procedures cover:

- Establishment of a direct assessment plan -RMP-09 "Procedure for External Corrosion Direct Assessment"
- Procedures to ensure that the assessments are done with minimal environmental and safety risks are included in the RMP-09 "Procedure for External Corrosion Direct Assessment" and RMP-11 "Procedure for In-Line Inspections"

The Integrity Management Assessment Computer System (IMACS) provides:

- Work management of scheduled integrity assessment efforts
- Summary reports of the assessment schedules, assessment methods and identified threats.
- For assessments, the completion date in IMACS shall be the date when the ILI and ECDA are complete (pig pulled from trap and the last scheduled direct examination for an ECDA/SCCDA/ICDA is done).

[redacted] GTR0003409

4.3. Company Compliance

The overall process to develop Company's BAP is as follows:

1. Identify and prioritize threats using Risk Analysis Procedure(s) results. Section 3 Threat Identification: Risk Assessment describes the procedures for threat identification and ranking.

2. Risk rank the HCAs and prioritize assessments ensuring that risk and operational feasibility are considered. Risk ranking will occur as follows:
   - Calculate the risk for each HCA per RMP-01.
   - Determine the high risk HCAs. High risk HCAs are those with:
     A risk of one standard deviation above the median (29.83). In addition, all HCAs with a risk between the median and one standard deviation are further analyzed to determine if they are high risk. Those operating at or above 50% SMYS and above the median (22.52) are defined as high risk. Those operating above 30% SMYS and with a risk greater than the median minus one standard deviation (15.21) with a poor pipe condition report or third party or external corrosion report in the last 20 years are also defined as high risk.

     In addition, where threats of a manufacturing or construction defect, including seam defects, in a covered segment are identified and any one of the following conditions occur, the segment shall be considered a high risk segment in the baseline assessment plan or in any subsequent assessment.
     (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;
     (ii) MOP increases; or
     (iii) The stresses leading to cyclic fatigue increase.
   - As of December 17, 2007 the total HCA 2004 BAP completed mileage is 509 miles or 56%. This included all the defined "high risk" segments. The remaining HCA segments from BAP2004 will be assessed by December 17, 2012. New and reassessed HCA segments will be assessed per 49CFR part 192.905(c) and 192.939 respectively. Newly identified high risk segments (see above) including HCA segments with an activated seam threat, should to the greatest extent practicable, scheduled for assessment within 7 years of being put in the BAP.

3. Determine method best suited to assess the identified threats. Where competing methods are equivalent, select the most economical.

4. Schedule assessments to meet compliance dates. These dates shall be coded into GIS using a three digit alphanumeric code as follows:

   The first alpha code shall be the assessment type, I for ILI, E for ECDA (when subject to SCC and IC threats, and the segments are to be assessed using DA, the dates for these non-EC assessments do not need to be coded into GIS), P for Pressure Test, R for Replace, S for station piping assessment, C for CIS only as required by the State Lands Commission (CIS only is typically only an acceptable method for non HCA areas). The second two digit code shall be the last two digits of the year in which the assessments is to be performed.
5. Upload the assessment information into IMACS, the Company's Integrity and Risk Management schedule tool.

6. Print summary BAP report detailing, for each year, the pipe segments to be assessed, the proposed assessment methods, and the identified threats.

7. Have summary BAP approved by appropriate Company officials; document approval process and date.

4.4. Prioritize Assessment Schedule by Risk
B31.8S 5.10

Assessments of the HCAs shall be scheduled per 4.3.2 of this procedure.

4.5. Selecting the Best Assessment Method(s)

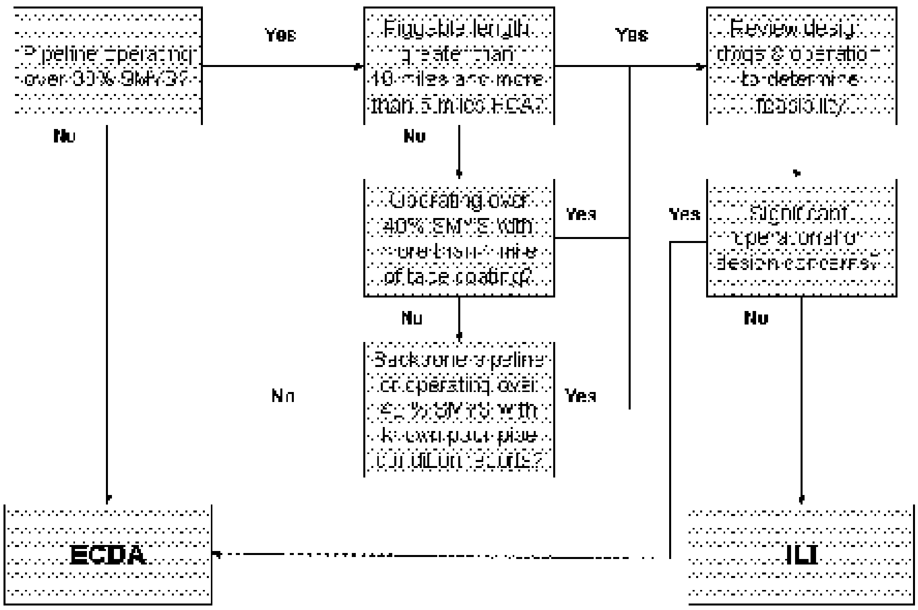
192.933 (b)

Scheduling integrity assessments for risk must also take into account the type of assessment method(s) that will be used in order to provide a BAP that is both comprehensive and practical. The methods chosen are based on the threats identified in the risk assessment procedure. More than one assessment method may be required to adequately cover the potential risks of an HCA. Guidelines as listed in Appendix A of B31.8S shall be used to make that determination.

For the two primary assessment methods the company plans to use to assess external and internal corrosion threats, ILI and DA, the following flowchart describes the high level process for selecting the appropriate method. The detailed processes for performing External Corrosion and Internal Corrosion DA are respectively contained in RMP's 09 and 10 (under development). RMP-11 provides a detailed procedure for performing an In Line Inspections (ILI).

Determining whether ILI or DA is the proper assessment tool for EC or IC on a segment is a two step process. The first step requires using the flowchart below. The results from that review will be used to initially select the assessment tool. The second step is the review made, during the course of the assessment process (Reference RMP's 09, 11 and 13), to confirm that the tool selected is still appropriate to assess the risk under consideration. This chart is primarily for first time assessments. Second time assessments will take into account the results of the first assessment and to help complement the first assessment, an alternate assessment method from that shown in this table may be selected.

Tool Selection Process
ILI vs. DA



The threat of stress corrosion cracking will primarily be assessed through the Direct Assessment process. A procedure for scheduling and prioritizing assessment digs for those segments which have a Stress Corrosion Cracking (SCC) threat is contained in RMP-13. SCC damage is also looked for at each bell hole dug as a part of the System Integrity Program, whether or not the segment being examined had been identified as having an SCC threat.

[redacted] GTR0003412

Where a pressure test is required as part of post-construction or an uprate for an existing line, the pressure test performed may be used in lieu of other methods as the assessment tool to assess internal and external corrosion, and stress corrosion cracking provided it is performed in accordance with subpart J of 49 CFR part 192. See Table III from B31.8S in Section 7.4 for requirements and limitations.

To address manufacturing threats in low frequency welded ERW pipe with pipe seams concerns, pressure testing will predominately be used as our assessment method when raising the MOP of the pipeline above the highest MOP recorded in the last 5 years. Pressure testing shall be in accordance with ASME B31.8 and subpart J of 49 CFR part 192. to at least 1.25 times the MOP. Low frequency welded ERW pipe with a manufacturing threat requiring assessment may also be assessed using a technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies, including a transverse field inspection tool.

For other threats, integrity assessment will be by addressed by prevention and mitigation actions.

4.6. Use of Prior Assessments

192.921(e)

Assessments made before December 17, 2002, may be used as baseline assessments if the integrity assessment meets the baseline requirements of Subpart O and the operator has taken subsequent remedial actions to address the conditions that are listed in §192.933. The re-assessment of these HCAs must be done **no later than** December 17, 2009. There are only a few pipelines containing HCAs whose prior assessments will be utilized. These HCAs are documented in GIS, IMACS, and Assessment Mileage Table.

4.7. Direct Assessment Plan

Depending on the threat addressed, direct assessment may be needed. See Section 5.6 for the Direct Assessment Plan.

4.8. Additional Considerations for Assessment Scheduling

The risk factors considered in scheduling shall be documented. See Sections 2 and 3 on data integration.

192.921(g)

Newly installed pipe that are HCAs or newly identified HCAs must be scheduled for assessment within 10 years from the date the pipe is installed or the new HCA identified. For new pipe, a post-installation pressure test per subpart J of 192 can be used as the baseline assessment. An operator must use the test pressures specified in Table 3 of Section 5 of B31.8S to justify an extended re-assessment interval in accordance with §192.939.

192.919(e)

The baseline assessment must be done in a manner that minimizes environmental and safety risk. Section 16 describes the Company program for ensuring this occurs.

4.9. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-09 "External Corrosion Direct Assessment Procedure" RMP-11 "Procedure for In-Line Inspections"		As needed As needed	RM File 7.9 RM File 7.11
RMP-13 "Procedure for Stress Corrosion Cracking Direct Assessment"		As needed	RM File 7.13

[redacted] GTR0003413

4.10. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Baseline Assessment Plan (BAP) List	Risk Mgmt File 7.6

4.11. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager Senior Risk Management Engineer and Risk management Engineer	Manager of Integrity Management Integrity Management Program Manager	Oversees development of BAP. Can also perform this work. Under the direction of the Integrity Management Program Manager, prepares and revises BAP.
Manager of Integrity Management	Director of Integrity Management and Technical Support	Approves BAP.
Director of Integrity Management and Technical Support	Sr. Director Gas Engineering	Approves BAP.
Senior Director Gas Engineering VP – Gas Transmission and Distribution	VP Gas Transmission and Distribution Sr. VP – Engineering and Operations	Approves BAP Provides Final Approval to BAP

4.12. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Initial BAP completed Complete baseline assessment for at least 50% of HCAs identified in original BAP including the highest risk HCA's.	Reviewed annually for additions. On-going updates as assessments results establish re-assessment intervals. December 17, 2007
Complete baseline assessment on remaining 50% of HCAs	December 17, 2012

5. Integrity Assessment including the Direct Assessment Plan

5.1. Scope

This Section describes the tools and methods selected to assess pipeline integrity and the process by which the assessment results are collected and integrated with other data.

5.2. Background

192.921

The Company will choose the method or methods best suited to assess the identified threats to the HCA. These methods may include:

1. In-line inspection tools (ILI) per RMP-11 which may include:
    - Metal loss tools for external and internal corrosion
    - Crack Detection tools for Stress Corrosion Cracking (SCC)
    - Metal loss and caliper tools for third party and mechanical damage
    - MFL tool to measure residual magnetism to assess areas with different hardness
2. Pressure testing
3. Direct assessment
    - External Corrosion Direct Assessment (ECDA): per RMP-09
    - Internal Corrosion Direct Assessment (ICDA): RMP-10
    - Stress Corrosion Cracking Direct Assessment (SCCDA) per RMP-13
    - Confirmatory Direct Assessment (CDA): under development

Other technology may be used that provides an equivalent understanding of the pipeline condition. If used, the Office of Pipeline Safety (OPS) and the CPUC must be notified 180 days before conducting the assessment. See Section 15 "Notification of Authorities" for the notification procedure.

Other processes may also be used depending on the type of threat(s) to which the pipeline is susceptible. These include surveys to consider such factors as land movement, pipe movement, outside forces, welding procedure reviews and visual inspection reports.

5.3. Company Compliance

The Company Procedures and Standards detailing the process for appropriately utilizing the approved assessment methodologies are as follows:

- ILI…RMP-11
- Pressure Testing…GS&S A-37
- ECDA…RMP-09
- ICDA RMP-10
- SCCDA RMP-13

5.4. Inline Inspection

It is the Company's desire to inspect pipelines utilizing In-Line Inspection (ILI), whenever it is physically and economically feasible. Some of the considerations used to determine feasibility include:

- Minimum length of at least 10 miles, that is predominately located in HCAs
- Less than 0.5 miles of replacement required to make the pipeline piggable
- Flow rates that enable a successful ILI
- Pipeline operation over 30% SMYS

For a high level flowchart of the decision making process see section 4.5.

[redacted]

GTR0003415

5.5. Pressure Testing

The Company does not plan to use pressure testing to assess the integrity of its pipelines, unless it is a post installation test or up-rate test for a new HCA. However, during the course of assessing data for ECDA or ILI, it may become apparent that pressure testing is the only feasible option. If so, the Company will perform a pressure test following the requirements found in Company's Gas Standards and Specifications A-37.

5.6. Direct Assessment

192.923

Direct Assessment assesses integrity by the use of a structured process to integrate knowledge of the physical characteristics and operating history of a pipeline with results of inspection, examination and evaluation. It can be used as a primary method only for external and internal corrosion, and stress corrosion cracking. It may also be used as a supplement to other methods.

External Corrosion Direct Assessment (ECDA)

192.925
B31.8S 6.4
NACE RP 0502

External Corrosion Direct Assessment is one method that may be used to determine the threat of external corrosion on the integrity of an underground pipeline. The focus of the ECDA approach is to identify locations where external defects may have formed; however, it may also detect evidence of such threats as mechanical damage. ECDA, as described in Appendix B of B31.8S can be used as an initial baseline inspection.

ECDA uses non-intrusive (above ground or indirect) examinations to estimate the success of corrosion protection. Excavations are made to confirm the ability of the indirect examinations to locate active and past corrosion and areas of significant coating damage. Then post assessments are made to determine re-inspection intervals and assess performance measures.

ECDA must meet the requirements of 192.925, of B31.8S Section 6.4 and NACE RP 0502. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information to evaluate the HCA for the threat of third party damage, and to address the threat as required by §192.917(e)(1).

The Company procedure RMP-09 details the processes and requirements for ensuring an effective ECDA. The Company participated with OPS and Keyspan Energy to produce the ECDA video that has been used to communicate the process. A summary of the process is as follows:

NACE RP 0502 Section 3

ECDA is a four-step process.

1. **Pre-assessment:** provides guidance for selection of the pipeline segment and which indirect methods to used. Also identifies ECDA regions (refer to RMP-09 for definition of ECDA Regions), areas within a pipeline segment that are suitable for the same indirect exam methods.

NACE RP 0502 Section 4

2. **Indirect Examination:** indirect aboveground electrical surveys are performed to detect coating defects and the level of cathodic protection. A minimum of two complimentary survey processes is required. The results of these surveys are weighed against established protocols to identify and prioritize locations for direct examination.

[redacted] GTR0003416

NACE RP 0502 5

NACE RP 0502 5.5.2.2

3. **Direct Examination:** excavations expose the pipe surface for metal-loss measurements, estimated corrosion growth rates, and measurements of corrosion morphology estimated during indirect examination. This step collects information to characterize any corrosion defects present and confirms the ability of non-intrusive inspections to locate active and past corrosion on a pipeline.

NACE RP 0502 Section 6

NACE RP 0502- Appendix D

4. **Post Assessment and Continuing Evaluation:** sets re-inspection intervals, provides a validation check, and provides performance measures. Intervals are determined by the number of excavations made as well as the repair activity and the operating pressure of the segment. The validation check consists of at least one additional excavation performed at the location estimated to contain the next most severe defect not previously subjected to direct examination.

Internal Corrosion Direct Assessment (ICDA)

192.927

B31.8S 6.4 and Appendix B2

Internal corrosion is most likely to occur where water first accumulates. Internal Corrosion Direct Assessment (ICDA) is a method that can assess for this threat on segments that normally carry dry gas but may have short term upsets of wet gas or free water (or other electrolytes) which may accumulate in low points or inclines. It is not to be used on segments where electrolyte is nominally present in the gas stream unless an ICDA plan is developed for that specific situation that effectively addresses internal corrosion and notification is provided in accordance with §192.921 (a)(4) or §192.937(c)(4).

The process identifies areas where fluids are likely to reside, then focuses direct examination on those areas, followed by post-assessment evaluation and monitoring.

ICDA must meet the requirements of 192.927 and B31.8S Section 6.4 and Appendix B2. The Company is currently developing its ICDA procedure. This procedure will comply with NACE requirements and will include the following steps:

ICDA is a four-step process.

1. **Pre-assessment:** gathers information to evaluate the feasibility of ICDA and a model to identify entrainment areas and ICDA regions.

2. **ICDA Region identification:** consists of the entire areas along a pipeline where internal corrosion may occur starting from the location where liquid may first enter. An ICDA Region may include one or more HCAs.

3. **Identification of locations for excavation and direct examination:** performed where electrolytes are most likely to occur and at least one excavation in an HCA.

4. **Post-assessment evaluation and monitoring:** validates the ICDA process using one or more additional digs at predicted water accumulation sites with inclination angles greater than the critical angle.

Stress Corrosion Cracking Direct Assessment (SCCDA)

Stress Corrosion Cracking Direct Assessment is one method that may be used to determine the threat of stress corrosion cracking on the integrity of an underground pipeline. The focus of the SCCDA approach is to identify locations where SCC may have formed; however, it may also detect evidence of such threats as mechanical damage.

Direct Assessment as a Supplemental Method

192.923(c)

If Direct Assessment is used as a supplemental assessment method, it must follow the requirements of 192.931. See Section 8 Confirmatory Direct Assessment for more information.

5.7. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-09 RMP-10	External Corrosion Direct Assessment Procedure Dry Gas Internal Corrosion Direct Assessment	As Needed As Needed	RM File 7.9 RM File 7.10
RMP-11	In-Line Inspection Procedure	As Needed	RM File 7.11
RMP-13	Procedure for Stress Corrosion Cracking Direct Assessment	As Needed	RM File 7.13
GS&S A-37	Hydrostatic Testing Procedure	As Needed	Tech Info library

5.8. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Field Engineer Process	

5.9. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Direct Assessment (DA) Program Manager	Manager, System Integrity	Ensure HCAs are assessed on time and following the process specified in RMP-09
Corrosion Engineer	Corrosion Engineering Supervisor	Performs all engineering related to the DA process. Reviews indirect assessment results, specifies locations for direct assessment, performs root cause evaluations, and performs post-

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		assessment.
In-Line Inspection (ILI) Program Manager	Manager, System Integrity	Ensure HCAs are assessed on time and following the process specified in RMP-11.
Integrity Management Program Manager	Manager, System Integrity	Schedule Integrity Assessments, re-assessments and integrate data into GIS

5.10. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Develop ICDA procedure	
Develop CDA procedure	

6. Remediation

6.1. Scope

Remediation is defined as action taken by the operator to mitigate the danger of a potential integrity concern. Remediation includes pressure reduction and/or repair and preventive measures that halt a potential integrity problem so it does not proceed to failure. This Section describes repair criteria that address issues identified by integrity assessment and data analysis. Preventive and mitigative measures are addressed in Section 9.

6.2. Background

192.933

The Company shall take prompt action to evaluate all discovered anomalies and remediate those that may threaten a pipeline's integrity.

The Company must be able to demonstrate that the remediation of a condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline until the next scheduled re-assessment.

If the Company is unable to respond within the prescribed time limits for any condition, operating pressure will be reduced or other measures taken to ensure the safety of the HCA. This reduction in pressure for an anomaly of concern cannot exceed 365 days unless the Company provides a technical justification that the continued pressure restriction will not jeopardize public safety or environmental protection. (reference RMP-11). The technical justification shall be documented and retained in the company's RM Files for audit.
All repairs must be per ASME B31.8 requirements.

6.3. Company Compliance

The Company's established repair procedures and schedules are specified in the procedures developed for the different inspection methods:

- ECDA – RMP-09
- ILI – RMP-11
- SCCDA-RMP-13

6.4. Discovery of a Condition

192.933 (b)

Discovery of a condition is defined as that date when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must obtain sufficient information about a condition no later than 180 days after an integrity assessment, unless the operator can demonstrate that the 180-day period is impractical.

For the following assessment techniques, "discovery of condition" occurs when:

- **ECDA** the direct examination phase of the anomaly is completed.

- **ILI** the Company receives documentation that there are anomalies meeting CFR 49, Part 192, Section O, Table 5.4.1 description of "Immediate repair conditions". This could occur in the preliminary and/or the final report from the ILI vendor.
- **SCCDA**-Following completion of the Magnetic Particle inspection and evaluation of any crack clusters found.

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6.5. Classification of Anomalies

Certain types of anomalies must be scheduled for repair and/or mitigation on a prioritized schedule, triggered by the dates of discovery. The prioritization shall include provisions for repair of the most dangerous defects in HCAs first, followed by the lesser anomalies, until all repairs and remediation activities have been completed. These classifications are detailed in RMP-09 and RMP-11.

6.6. Scheduling Remediation

Company shall prioritize the evaluation and remediation of conditions and set its repair schedule to remediate the most critical conditions first. All reports from integrity assessments shall be promptly reviewed and immediate repair conditions scheduled. Other conditions shall be reviewed within180 days and a response plan (repair schedule) developed.

The repair schedule shall include the methods and timing of the response.

The schedule for remediation follows the guidelines for repair conditions in B31.8S Section 7 unless special requirements apply. If Company cannot meet this schedule, Company shall:

- Justify the reasons why it cannot meet the schedule
- Demonstrate that the delay will not jeopardize public safety

If Company cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure, then the OPS and the CPUC must be notified per 192.949. See Section 15 Notification of Authorities for instructions on the notification process.

Additional Scheduling Considerations

Different responses in scheduling may be indicated depending on the type of integrity assessment conducted. B31.8S discusses these; they are listed in B31.8S table 3 and in Section 7.4 of this procedure.

6.7. Repair Methods

B31.8S Table 4 lists repair and prevention/detection methods that are acceptable for each of the nine threat categories.

Those repair methods typically used by Company include:

- Pipe replacement
- Sleeves and patches
- Composite sleeves
- Grinding
- Fill welds
- Direct deposition welding

[redacted]

6.8. Procedures This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-09	ECDA Procedure	Update as needed	RM File 7.9
RMP-11	ILI Procedure	Update as needed	RM File 7.11
RMP-13	SCCDA Procedure	Update as needed	RM File 7.13
UO Standard S4134	Selection of Steel Gas Pipeline Repair Methods	Intentionally left blank	Technical Information Library

6.9. Supporting Documents The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
See RMP-09 and RMP-11	See above

6.10. Roles and Responsibility Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
See RMP-09, RMP-11 and RMP-13	Not Applicable	Not Applicable

6.11. Calendar The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Review this section	Integrity Management Program Manager

[redacted]

GTR0003422

7. Continual Evaluation and Assessment

7.1. Scope

192.937

This Section outlines the schedules used for re-assessment, the periodic evaluation of HCA integrity according to criteria specified in the regulation, and the assessment methods.

7.2. Background

192.939

After the Baseline Assessment is complete (Based on BAP of 12/17/04), an operator must continue to assess all HCAs according to the intervals listed in 192.939 and periodically re-assess ensure continuing integrity.

Where prior assessments to 12/17/02 were used to meet BAP requirements, re-assessment must be performed no later than December 17, 2009.

All HCAs must be re-assessed by some method no later than seven years (5 years for DA'd segments operating at or over 50% SMYS where all anomolies have not been remediated) after the baseline assessment, or sooner if indicated by evaluation.

The presence of time-dependent modes of deterioration from some conditions makes repeated inspection imperative. Company has developed a process for continual integrity assessment and evaluation to maintain the integrity of HCAs. All activities performed in conjunction with Company's Integrity Management Program are an integral part of this cycle. These activities, modified and updated throughout each cycle, form a dynamic process with ongoing improvements.

Company will ensure that ongoing assessment intervals for HCAs do not exceed the seven-year requirement (5 years for DA'd segments operating at or over 50% SMYS where all anomolies have not been remediated) established in the rule. However, certain threats to specific pipeline operating conditions, such as external and internal corrosion may require a reduced examination and evaluation interval. If assessment results or other associated risk factors indicate the need, higher risk areas shall receive more frequent evaluation and an adjustment to the seven-year interval.

At the conclusion of each assessment, a Long Term Integrity Management Plan (LTIMP) shall be developed based on the integrated assessment information, remediation performed, pipeline information, and environmental information to establish reassessment intervals and prevention and mitigation plans. (Remediation will have been completed as part of the assessment activities in RMP-09, RMP-11 and RMP-13.) The LTIMP shall be documented and include data considered, how the data was integrated, analysis, and recommendations. Upon approval of the LTIMP by the Manager of Integrity Management, the BAP, and IMACS shall be revised to reflect the updated plans. The LTIMP documentation shall be filed in the IM Files.

Both the regulatory requirements for re-assessment schedules (such as the maximum re-assessment interval chart) and the engineering basis (remaining half-life calculations) must be considered when establishing re-assessment intervals. (See § 7.4) In addition, the following shall be considered when determining re-inspection intervals and in recommending prevention and mitigation measures:

[redacted]

1. Previous integrity assessment results (e.g. anomaly type and size, defect growth rate, etc.)
2. Data integration and risk assessment information, including threat analysis results, as performed for the BAP and all subsequent re-assessments for the considered threat as well as for other threats
3. Pipe size, material, manufacturing information, coating type and condition, and seam type
4. Decisions about remediation, including leak and repair history
5. Product transported, including historical changes
6. Operating stress level (including potential for pressure cycle)
7. Existing or projected operation and maintenance activities, including additional preventive and mitigative activities
8. Any changes to the pipeline system design and operation, including any external changes that may have occurred since the last risk assessment
9. Local environmental factors that could affect the pipeline
10. Geotechnical hazards (earthquakes, landslides, erosion, etc.)
11. An analysis of all information and data about the integrity of the pipeline segment and the consequences of a failure
12. Scope of assessment (vs. intended scope)
13. Tool tolerance and Data Quality.
14. Consideration of providing prevention and mitigation measures to other pipeline segments (covered and non-covered) which have similar material and environmental characteristics.
15. Where preventive and mitigative measures have been deemed necessary, a schedule for implementing these measures shall be entered in IMACS. Where appropriate this schedule shall comply with Gas Standard O-16 and UO Standard S4134. Where similar segments operating in an area with similar environmental characteristics have been identified, a schedule shall also be established for their evaluation. Where active corrosion has been identified, schedules shall also be made for establishing preventive and mitigative measures.

In performing the review of assessments and establishing prevention and mitigation strategies, the following additional factors, in addition to the requirements of section 9 of this procedure, must be considered:

16. Potential for Third Party Damage (Dig-Ins, farming activity, noted as higher risk by field, foreign line crossings, USA information)
17. Inspection and Incident History (A and H Forms)
18. Cathodic Protection Records or CIS results.
19. Potential for Stray Current.
20. Risk Mitigation Strategies such as:
    a. Improving the cathodic protection,
    b. Implementing additional inspection and maintenance programs,
    c. Improving Line Marking,
    d. Additional landowner notification or public awareness efforts,
    e. Installation of Automatic Shut-off Valves or Remote Control Valves per Section 9.7 of this procedure.
    f. Installation of computerized monitoring and leak detection systems,
    g. Replacing Pipe segments with pipe of heavier wall thickness, rerouting, or providing additional cover,
    h. Providing additional training to personnel on response procedures,
    i. Conducting drills with emergency responders.

A LTIMP Checklist (as shown Appendix F) or something similar will be used to ensure that all of the appropriate data was considered, and referenced.

7.3. Ongoing Evaluation

Normal operation and maintenance activities, including field reporting, engineering, and facility mapping processes, constantly produce data in addition to inspection and mitigation activities. This data shall be analyzed and integrated in a continual process and should data indicate serious concerns that were not previously identified, the integrity assessment and mitigation activities will be revised. These continual changes to the physical and operating aspects of the pipeline must be managed through the Management of Change process, Section 12.8.

As stated in Section 2.3 and RMP-01 Section 6.5 risk analysis and threat identification will be reviewed annually. This review will identify if new high risk segments were created. If new high risk segments were created, the BAP will be reviewed and assessments re-scheduled as appropriate with their risk and applicable threats.

7.4. Assessment Intervals

Re-assessment intervals are dependent upon the operating pressure at which the HCA operates, which type of assessment method was chosen for the Baseline Assessment and the actions taken as a result of the assessment. Table E.II.2 of Appendix E of the regulation and the Maximum Reassessment Interval chart from 192.939 of the regulation detail the maximum allowed re-assessment intervals. Table 3 of B31.8S also provides additional requirements in this area for Time-Dependent Threats.

Adjustments in the chosen assessment method and/or improvements to the risk assessment method(s) in use may become necessary as more complete and accurate information on the HCAs is accumulated. The specific threats and assessment techniques for each HCA is documented in the BAP.

For pipelines operating at or above 50% SMYS, a re-assessment of five years may be required, see note 4 of Table III (table follows in this section) for requirements.

For pipelines operating below 30% SMYS, low stress assessments may be used every seven years in place of CDA.

192.939 Re-assessment Interval Chart

MAXIMUM REASSESSMENT INTERVAL

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years(**)
Confirmatory Direct Assessment	7 years	7 years	7 years
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in § 192.941

(*) A Confirmatory direct assessment as described in § 192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.
(**) Low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

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Table III B31.8S

Inspection Technique	Interval (Note 1)	>= 50% SMYS	30 - <50% SMYS	< 30% SMYS
Hydro test	5	TP to 1.25x MAOP (Note 2)	TP to 1.4x MAOP (Note 2)	TP to 1.7x MAOP (Note 2)
	10	TP to 1.39x MAOP (Note 2)	TP to 1.7x MAOP (Note 2)	TP to 2.2x MAOP (Note 2)
	15	Not Allowed	TP to 2.0x MAOP (Note 2)	TP to 2.8x MAOP (Note 2)
	20	Not Allowed	Not Allowed	TP to 3.3x MAOP(Note 2)
In-Line Inspection	5	PF > 1.25x MAOP (Note 3)	PF > 1.4x MAOP (Note 3)	PF > 1.7x MAOP (Note 3)
	10	PF > 1.39x MAOP (Note 3)	PF > 1.7x MAOP (Note 3)	PF > 2.2x MAOP (Note 3)
	15	Not Allowed	PF > 2.0x MAOP (Note 3)	PF > 2.8x MAOP (Note 3)
	20	Not Allowed	Not Allowed	PF > 3.3x MAOP (Note 3)
Direct Assessment	5	Sample of indications examined (Note 4)	Sample of indications examined(Note 4)	Sample of indications examined (Note 4)
	10	All indications Examined	Sample of indications examined (Note 4)	Sample of indications examined (Note 4)
	15	Not Allowed	All indications Examined	All indications Examined
	20	Not Allowed	Not Allowed	All indications Examined

Notes:

(1) Intervals are maximum and may be less, depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Occurrence of a time dependent failure requires immediate reassessment of the interval.

(2) TP Test Pressure

(3) PF Predicted Failure Pressure as determined from ASME B31G or Equivalent

(4) For the Direct Assessment Process, the intervals for direct examination of indications are contained with the process. These intervals provide for sampling of indications based on their severity and the results of previous examinations. Unless all indications are examined and repaired, the maximum interval for re-inspection is 5 years for pipe operating at or above 50% SMYS and 10 years for pipe operating below 50% SMYS

(5) This Table is taken from B31.8S. In PG&E documentation for pipelines operating over 60 psig, the term MAOP is reserved for the maximum allowable pressure a particular segment of pipe may be subjected to. The maximum allowable pressure for a string of segments (a pipeline) is documented as the MOP and is the value to be used when this table references the MAOP..

Table E.II.2 from Appendix E

Table E.II.2 Assessment Requirements for Transmission Pipelines in HCAs (Re-assessment Intervals are maximum allowed)						
Re-Assessment Requirements (see Note 3)						
	At or above 50% SMYS		At or above 30% SMYS up to 50% SMYS		Below 30% SMYS	
Baseline Assessment Method (see Note 3)	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method
Pressure Testing		CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	Pressure Test or ILI or DA				
		Repeat inspection cycle every 10 years	15 (see Note 1)	Pressure Test or ILI or DA (see Note 1)		
				Repeat inspection cycle every 15 years	20	Pressure Test or ILI or DA
						Repeat inspection cycle every 20 years
In Line Inspection	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	ILI or DA or Pressure Test				
		Repeat inspection cycle every 10 years	15 (see Note 1)	ILI or DA or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	ILI or DA or Pressure Test Repeat inspection cycle every 20 years
Direct Assessment	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	DA or ILI or Pressure Test				
		Repeat inspection cycle every 10 years	15 (see Note 1)	DA or ILI or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	DA or ILI or Pressure Test
						Repeat inspection cycle every 20 years

Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S
Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of PM&M
Note 3: Operator may utilize "other technology that an operator demonstrates can provide an equivalent understanding of the condition of the pipe"

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7.5. Assessment Methods

Company used a detailed process for selecting the appropriate assessment tools. The procedures for selecting re-assessment methods is generally the same as those as described in Section 4.5 Baseline Assessment Plan with the addition of confirmatory direct assessment (CDA) and electronic surveys as assessment tools. CDA and electronic surveys can be used on an HCA when the scheduled re-assessment exceeds seven years and must comply with the conditions outlined in Section 8 Confirmatory Direct Assessment. The difference in the tool selection process between the first and subsequent assessments is that findings from previous assessments shall be considered in selecting the second assessment method. This may also result in the selection of an alternate method from that method used in the first assessment

7.6. Using Low Stress Re-Assessments

192.941

This method can only be used for pipelines operating below 30% SMYS and must have had a baseline assessment per 192.919 and 192.921. The requirements for different threats are as follows:

External Corrosion Requirements

- Conduct an electric survey on cathodically protected pipe (i.e. indirect examination tool/method (procedure to be developed prior to performing to survey) at least every seven years on the HCA. The results of each survey shall be used as part of an overall evaluation of the cathodic protection and corrosion threat for the HCA and include, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
- Assess unprotected pipe or cathodically protected pipe, where electrical surveys are impractical, with:
  - Leakage surveys as required by §192.706 at four-month intervals.
  - Areas of active corrosion shall be identified and remediated every 18 months by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

Internal Corrosion Requirements

- Conduct a gas analysis for corrosive agents at least once each year
- Conduct testing of fluids removed from each storage field that may affect a HCA at least once each year

The data from these tests must be integrated at least every seven years with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records. Then appropriate remediation actions shall be defined and implemented.

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7.7. Deviation from Assessment Intervals

192.943

There may be situations when additional time is required to assess pipeline segments. Situations that could prolong assessment include:

- Internal inspection tools cannot be obtained within the required re-assessment period. Should this occur, Company must take whatever actions necessary to ensure the integrity of the segment during the interim.
- Product supply cannot be maintained if assessment is done within the required interval.

In these cases, Company will apply for a waiver from the OPS at least 180 days prior to the end of the required interval or as soon as product supply indicates the need for the waiver. A waiver application shall be filed in accordance with section 15.2 of this procedure. A copy shall also be submitted to the CPUC for their information.

7.8. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-09	ECDA procedure	Update as needed	RM File 7.9
RMP-11	ILI procedure	Update as needed	RM File 7.11
RMP-13	SCCDA Procedure	Update as needed	RM File 7.13

7.9. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Integrity Management work management system (IMACS)	Work Mgmt software
Standard S4110 Leak Survey and Repair of Gas Transmission and Distribution Facilities	Technical Information Library-online

7.10. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
See RMP-09 and RMP-11 and RMP-13	**Not applicable**	**Not applicable**

7.11. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Not applicable	

[redacted] GTR0003429

8. Confirmatory Direct Assessment

8.1. Scope

192.931

Integrity regulations allow an operator to use Confirmatory Direct Assessment (CDA) to meet the seven-year re-assessment requirement when the suggested re-assessment period for the baseline assessment method is longer than seven years.

8.2. Background

192.937 (c)(5)

Confirmatory Direct Assessment is an assessment method that can be used in limited circumstances for re-assessment. CDA follows the ECDA and ICDA plans with some exceptions.

8.3. Company Compliance

A procedure for CDA has not been developed at this time. This process will not be used unless a procedure for that process has been developed.

8.4. Allowable Uses

CDA may only be used for external corrosion and internal corrosion re-assessments.

8.5. External Corrosion Plan

CDA for external corrosion shall follow the ECDA Plan per 192.925 with the following exceptions:

- Use of only one indirect examination tool is allowed.
- All indications of immediate action must be excavated for each ECDA Region (refer to RMP-09 for a definition of ECDA Region).
- At least one high-risk indication meeting scheduled action criteria must be excavated in each ECDA Region.

8.6. Internal Corrosion Plan

CDA for internal corrosion shall follow the ICDA Plan per 192.927 with the following exception: only one excavation of high-risk location in each ICDA Region is required.

8.7. Scheduling and Repairs

If a defect revealed during CDA requires remediation prior to the next scheduled assessment, then the next assessment must be re-scheduled in accordance with the requirements of RP 0502 6.2 and 6.3.

If the defect requires immediate remediation, pressure must be reduced per 192.933 until the segment is re-assessed per 192.937.

8.8. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
CDA Procedure	To be developed.		

[redacted] GTR0003430

8.9. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
To be developed	

8.10. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
To be developed	Not applicable.	Not applicable.

8.11. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Review as necessary.	Integrity Management Program Manager.

9. Preventive and Mitigative Measures

9.1. Scope

192.935

This section addresses additional preventive and mitigative measures that Company is taking to protect High Consequence Areas in accordance with 192.935.

9.2. Background

192.935

Section 192.935 requires the development of additional preventive and mitigative measures that address the following:

- Prevention of third party damage
- Prevention of outside force damage
- Automatic shut-off valves or remote control valves
- Low-pressure pipeline measures
- Also see section 7.2 for other necessary prevention and mitigation considerations.

9.3. Company Compliance

Table 4 B31.8S

The Company has established programs that address many of the suggested preventive and mitigative measures, both from 192.935 and those suggested in Table 4 of B31.8S.

Additional new measures shall be developed or existing measures refined as part of the Company's continuing evaluation and improvement program.

The following table summarizes the established processes and procedures included in Company's preventive and mitigative measures. More comprehensive descriptions of these programs/procedures follow the table.

Current Preventive and Mitigative Processes and Procedures

Prevention/ Detection Methods	Company Compliance Description	Procedure	Location
192.935			
Use of qualified personnel for marking, locating and supervision of excavations	OQ Qualified, Mark and Locate Annual Training,	UO S4412, Damage Prevention Manual	Technical Information Library
Maintaining an excavation damage database (damage not limited to reportable incidents)	Incident report for every incident of known excavation damage and Risk Mgmt spreadsheet tracking root cause and relative likelihood of each incident		PG&E Risk Management Web Site
Monitoring of excavations	Stand-by all Gas Transmission facilities within 5 foot of any excavation	UO S4412, WP4412-06, Damage Prevention Manual, 2006 Safety Video – Excavation and Stand-By	Technical Information Library

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Prevention/ Detection Methods	Company Compliance Description	Procedure	Location
First Responder Training and Preparation	Bi-Annual First Responder Program (FRP) *Pre Fire Plan Manuals for each Compressor Station	RMP-12	District Offices & Compressor Stations
Local Emergency Responder Drills	Annual Emergency District Drills	Simulate emergency situations at the compressor station or out on the pipeline. See Emergency Manual	District compressor station or field locations
Improved/Additional Inspections and Maintenance Improved/Additional Inspections and Maintenance	Semi-annual leak survey for all Class 3 & 4 transmission lines not assessed using ILI/DA or PT Gas Transmission Earthquake Plan and Response Procedure	Standard S4110 RMI-04	Technical Information Library Risk Management Files
Improved/Additional Inspections and Maintenance	Gas Transmission Rainfall Plan and Response Instruction	RMI-04A	Risk Management Files
Automatic and Remote Valves	LTIMP Review	RMP-06	Risk Management Files
Excavate or conduct above ground surveys in areas of unmonitored encroachments Warn landowners of shallow pipe	Protect pipelines from encroachments and other unsafe activities near our facilities Natural Gas Pipelines with Elevated 3rd Party	SHC 104 Observed Hazard Notification Third Party GIB 187	Technical Information Library Technical Information Library
Table 4: B31.8S			
Patrolling			
Aerial	Quarterly patrols with increased frequency during months with active agriculture	Standard S4111	Technical Information Library/local headquarters
Foot	Quarterly patrols with increased frequency during months with active agriculture	Standard S4111	Technical Information Library for standard/local headquarters for patrol records.
One Call Systems	Utilize California's Underground Service Alert for any excavations		
Public Education	Public Safety Information Program (PSIP) events concerning pipeline hazards and utilization of USA. Property owner	RMP-12; Landowner notification program documented in hardcopy files and on server.	PG&E PSIP web site Sample landowner notification letter

[redacted] GTR0003433

Prevention/ Detection Methods	Company Compliance Description	Procedure	Location
	notifications (PSIP) provide Pipeline safety information to the public and USA.		

9.4. Risk Drivers for Establishing P&M Actions

Preventive and mitigative measures are based on the threats documented in Section 3 "Threat Identification" section of this procedure.

Section 5 B31.8S

Risk Assessment methods in Section 5 of B31.8S, outlined in the Section 0 "Integrity Assessment", identify additional measures to protect HCAs. Following are the additional measures and their application within the Company's Integrity Management Program.

9.5. Preventing Third-Party Damage

Third party damage is consistently a major cause of pipeline releases. Information on the location of excavation damage that occurs in the transmission system shall be maintained for both HCAs and non-HCAs. Additional P&M measures shall be considered in the Long Term Integrity Management Program (LTIMP) (See Section 7.2 requirements for LTIMP and Appendix F. B.5.c) and RMP-01 Section 7.1.

Company has take the following steps to help prevent third-party damage:

- Participation in Underground Service Alert (USA)
- Participation in Pipeline Association for Public Awareness
- Mandatory standby for any excavations within 5' of gas transmission facilities
- Landowner notification for portions of gas transmission facilities whose cover is less than required for a new installation (every two years)
- Landowner notification for all portions of gas transmission facilities with a history of 3rd Party damage or identified by operations personnel as vulnerable (every two years). RMP-12 section 5.2.
- Developed video documenting the process for locating, marking, stand-by and excavation around gas transmission facilities to educate our own personnel and contractor groups.
- Public presentations about 3rd party damage prevention.
- Additional pipeline markers

Many of these steps are documented in RMP-12, PG&E's Pipeline Public Awareness Plan.

9.6. Outside Force Damage

All pipelines that are at risk from outside force damage, including earth movement, floods, and suspension bridge instability, shall receive additional preventive and mitigative attention. Some of these activities may include:

- Patrolling of vulnerable facilities after a seismic event…See RMI-04
- Patrolling of vulnerable facilities after sufficient rain…See RMI-04A
- Maintaining a prioritized erosion database and GIS layer
- Replacement of pipeline with design more likely to survive event
- Relocation of the pipeline

[redacted] GTR0003434

9.7. Valves

Company follows a set of guidelines for all its pipelines concerning valve placement.

In-line Valves

Company may employ in-line valves on specific pipelines in sensitive areas to mitigate the effects of a possible release. The specific guidelines for utilizing in-line valves need to be developed and the Integrity Management Program Manager is responsible for ensuring these guidelines are implemented prior to 12/31/09.

Automatic Shut-off and Remote Controlled Valves

As part of the LTIMP and in addition to normal valve replacement, Company shall consider the addition of automatic shut-off valves (ASV) or remote control valves (RCV) if they would be an efficient means of adding protection to an HCA Per letter to RM file 8.10 dated 6/14/06 by Chih-Hung Lee. the company has concluded (based on referenced documents) that, in most cases, the uses of ASV's or RCV's as a Preventative and Mitigation measure in a HCA has little or no effect on increasing human safety or protecting pipelines. ASV or RCV may, however, help reduce shutdown time and gas releases during repair which will reduce repair cost and improve system recovery.

In comparing ASV and RCV, the company prefers RCVs over ASVs due to many issues regarding RCV. Installation of ASVs or RCVs is a mitigative measure to minimize cost after a pipeline rupture.

Certain cases require specific review as follows:

1. We do not recommend using ASV or RCV as a general mitigation measure in HCAs, however, for some specific conditions such as: bridge crossings, river crossings, earthquake fault crossings, etc. RCVs may be installed for economic and operational reasons. Consideration shall include existing isolation valves, response time following a failure, likelihood of rupture (for example the mitigative measures that have already been implemented to prevent a rupture), and proximity and type of structures or gathering areas around the pipeline.
2. A review by the unique attributes during the LTIMP process (RMP-06 Section 7.2) shall be performed to determine if additional RCV(s) or ASV(s) are warranted. Each case shall be thoroughly reviewed before any the appropriate valve is installed.

Maintenance and Operation of Valves

The Company shall follow CFR 49, Part 192, Subpart D, paragraphs 192.145 and 192.179 for the design and Subpart M, paragraph 192.745 for the maintenance of transmission line valves. The following Company procedures specify the details governing the Company's valve design and maintenance:

Valve Design:

Specification and Testing are in conformance with API Specification 6D, "Specification Pipeline Valves (Gate, Plug, Ball, and Check Valves)". (21st edition, 1994)
Related PG&E Standards
GS&S F-10, Valve Selection Requirements
GS&S F-21 Standard Ball Valve List: Carbon Steel 2" through 24"

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GS&S F-21.1 Material Specification for Carbon Steel Ball Valves
GS&S F-31 Standard Carbon Steel Gate Valve List
GS&S F-40 Plug Valve - Codes and Data

Valve Maintenance:
Valve Maintenance is conduct in accordance with PG&E UO Standard S 4220, Valve Maintenance Requirements.

9.8. Minimizing Emergency Response Time

Operations personnel can receive information about pipeline leaks through pipeline system operations alarms, third-party observations, emergency response organizations, aerial patrols, and other means. Immediate response is imperative to any given situation involving an actual or suspected pipeline leak. Response procedures have been established for responding to pipeline emergencies. Those procedures will define an action plan that includes the following:

- A definition of organizational lines of responsibility and notification for response to unintended releases
- Training of all personnel responsible for responding to unintended release events
- Immediate verification of unintended releases, if necessary
- Isolation and control of the unintended release source

9.9. Low-Pressure Pipelines in Class Locations

[illegible]
Table 9.1.1
Appendix E
Table 9.1.3
Appendix E

Except as noted below, the Company has the following processes in place to address low-pressure that are HCA and non-HCA pipelines in Class 3 & 4 locations:

- Participation in California's one-call USA
- All excavations within 5 feet of gas transmission facilities, all boring activities when any kind of boring activity is crossing perpendicular to the pipe or will come within 10 feet of the nearest side of the pipe, all blasting activity within 10 feet of the pipe, and certain agricultural activities, are monitored throughout the excavation.
- Semi-annual leak patrols will be required for all transmission pipelines in Class 3 & 4 that are not HCAs.

9.10. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-12 Pipeline Public Awareness Plan	Public awareness plan for transmission and distribution facilities	As necessary	RM file 7.12
Damage Prevention Manual Leak Survey and Repair of Gas Transmission and Distribution Facilities S4110	See Title See Title	As necessary As necessary	Technical Information Library Technical Information Library
Patrolling Pipelines and Mains S4111	See Title	As necessary	Technical Information Library
Preventing Damage to Underground Facilities S4412	See Title	As necessary	Technical Information Library

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9.11. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
RMI-04 Gas Transmission Earthquake Plan and Response Procedure	Technical Information Library
RMI-04A Gas Transmission Rainfall Plan and Response Instruction	Technical Information Library
Gas Emergency Response Plans	Technical Information Library
Semi-Annual Leak survey folders	District/Division Headquarters

9.12. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Corporate PSIP Manager	Safety Health and Claims	Corporate public communications and awareness training
PSIP Manager	Supervisor of System Integrity	In charge of public communications and awareness training, and landowner notification
Director of Integrity Management and Technical Support	Senior Director of Gas Engineering	Responsible for all standards for maintenance and operation of gas transmission facilities
Various for RMI-04 and RMI-04A	Various	See RMI's for guidance

9.13. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
None.	

[redacted]

10. Performance Plan

10.1. Scope

192.945

This Section contains Company's Performance Plan, as required by 192.945, to determine that all integrity management program objectives are being accomplished and the integrity and safety of the pipelines are being effectively improved.

10.2. Background

B31.8S 9.4

A semi-annual evaluation of the elements of Company's Integrity Management Program must be made to ensure that the program is effective in assessing integrity and protecting high consequence areas. B31.8S 9.4 outlines four performance measures that must be included in addition to the specific measures for each threat as specified by B31.8S Appendix A.

Since External Corrosion Direct Assessment (ECDA) is used, this process must be per 192.925 (see Section 0 Integrity Assessment) and be monitored to ensure that the ECDA process is effectively assessing and mitigating risk. A semi-annual report to OPS and CPUC is due per 192.951 (see Subsection 10.4 and Section 15 Notification of Authorities).

[redacted] GTR0003438

10.3. Intra-system Measures

Company has developed a performance plan to perform intra-system comparisons and program measurements which address the following:

1. Overall program measurements including:
   - Number of miles of pipeline inspected compared to the program schedule
   - Number of immediate repairs completed
   - Number of scheduled repairs completed
   - Number of leaks, failures and incidents, classified by cause
2. DA effectiveness measures including:
   - Number of excavation performed each year (application of DA)
   - Number of Immediate repairs (results of the DA)
   - Number of Scheduled repairs (results of the DA)
   - Frequency of Immediate and Scheduled Indications
   - Number of leaks on pipelines with past DA surveys (absolute criteria)
3. All threat specific metrics for each of the nine threat categories as listed:
   - **Stress Corrosion Cracking**

     Repair/Replacements due to SCC

     Number of in-service leaks or failures due to SCC
   - **Failures during Pressure Testing**

     Due to EC

     Due to IC

     Due to SCC

     Due to Manufacturing Defect

     Due to Construction Defect

     Due to Equip failure

     Due to Outside Force
   - **Construction**

     Construction Threat Leaks and Failures

     Number of girth/coupling reinf/replacements

     Number of wrinkle bends removed

     Number of wrinkle bends inspected

     Number of other welds repaired/removed

     Number of Construction defect leaks
   - **Manufacturing**

     Number of Manufacturing defect leaks
   - **Equipment**

     Equipment Leaks and Failures

     Number of regulator valve failures

     Number of relief valve failures

     Number of gasket or O-ring failures

     Number of leaks due to equipment or Other
   - **Third Party Damage**

     Number of leaks on pipe caused by third party

     Number of leaks or failures on previously damaged pipe

     Number of leaks or failure by vandalism

     Number of repairs implemented as a result of third party damage

     Number of near miss
   - **Corrosion, Internal and External**

     Number of Internal Corrosion Leaks

     Number of External Corrosion Leaks

[redacted]

- **Incorrect Operations (leaks)**
  - Number of audits/review conducted
  - Number of Severe audit findings
  - Number of Moderate audit findings
  - Number of Minor audit findings
  - Number of Operating Errors
  - Number of Clearance violations
  - Number of Incorrect Operations leaks or failures
  - Number of changes to procedures due to audits/reviews
- **Outside Force**
  - Number of Repairs/replacement/relocation
  - Number of Outside Force leaks

4. Risk algorithm validation is performed as part of RMP01-05.

These measures will be used to prepare an annual evaluation of the long term effectiveness of the integrity management program including, the effectiveness of the ECDA process.

The \\WalnutCrk01\CGT\ENG\LIBRARY\ANREPORT\IMP\200*X (where X is the digit of the current year. E.g. 2006)*\IMPmetrics*monthyear(e.g.metrics0605)*.xls spreadsheet documents these metrics and is used to provide OPS, INGAA and internal audiences with summaries of the Integrity Management Program's progress and effectiveness.

10.4. Performance Reporting

Regulatory Communications

Semi-annual reports shall be issued to the OPS that includes the four performance measures listed in Section 10.3 per B31.8S Section 9.4. A semi-annual report must be submitted to the OPS and the CPUC per 192.945, beginning August 31, 2004. Subsequent semi-annual reports shall cover the period through June 30 and December 31 of each year and are due within two months of the cutoff date. The reports must be complete through June 30 and December 31 of each year and must be submitted by two months after those dates. The report submitted in August should include data for the first half of the calendar year. The report submitted in February should include data covering the entire calendar year (i.e., updating the information in the August report).

Internal Communications

Company shall use a monthly report to communicate the progress and effectiveness of the Integrity Management Program. The monthly report shall be distributed to the Vice President of Gas Transmission and Distribution, and shall document the work planned and completed during the year. In addition the semi-annual reports to the OPS and the CPUC shall be distributed to the VP of Gas Transmission and Distribution and the Senior Director of Gas Engineering to communicate the progress and effectiveness of the Integrity Management Program.

10.5. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-09 ECDA Procedure	ECDA Process	As needed	
RMP-11 ILI Procedure	ILI Process and data gathering	As needed	

10.6. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Risk Mgmt Annual Report to CPUC	Risk Mgmt Library

10.7. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager of Integrity Management	Select performance indicators for reports, Compile and submit performance reports
ILI /DA Program Manager	Manager of System Integrity	System performance metrics related to ILI and DA
Public Safety Information Program (PSIP) Manager	Supervisor of Gas System Integrity	Incident metrics
Compliance Engineer	Senior Director of Gas Engineering	Internal Audits

10.8. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Performance Reports to OPS, CPUC and VP Gas Transmission and Distribution	Semi-annual through June 30 and December 31 of each year (due by August 31, and February 28/29 of each year)and updated as new information becomes available
Monthly status reports to VP Gas Transmission and Distribution	Monthly updates to management by the 15th of the following month
Program Evaluation	Annual

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11. Record Keeping

11.1. Scope

This Section covers the records and supporting documentation that are part of Company's Integrity Management Program.

11.2. Background

§192.947

All records and other documentation that demonstrate compliance with the requirements of the integrity management regulations must be kept for the useful life of a pipeline. Section 192.947 lists the records, at a minimum, which must be available for review during an inspection.

11.3. Company Compliance

At minimum, these records shall include documentation which addresses the following:

- Written integrity management program
- Threat identification and risk assessment
- Baseline assessment plan
- Decisions, analyses, developed processes used to implement and evaluate each element of the baseline assessment plan and integrity management program
- Personnel qualification and training
- Schedule prioritizing conditions found during any process of the integrity management program
- Actions taken to comply with direct assessment requirements
- Actions taken to comply with confirmatory direct assessment requirements
- Files for each pipeline segment in an HCA including the long term integrity management section detailing any mitigation or prevention activities initiated by the assessment and documentation for the re-assessment schedule (see Section 7.2).
- All required documentation and notifications to OPS, state authorities with which OPS has an interstate agreement, and the CPUC.

These elements often consist of more than one source of documentation and/or records. The section for each element describes any required documentation, supporting reports, etc. Risk Management Instructions (RMI's) are prepared to serve as a guideline in compliance with the Risk Management Procedures. The RMI's are guidelines and not requirements. There can be many variations to the processes given in the RMI's that fully comply with the Integrity Management Procedures. ,

11.4. Roles and Responsibility

Responsibilities for ensuring compliance for record keeping are covered in the applicable section for each element of the integrity management regulation and are summarized in the Company Integrity Management Calendar for each section.

11.5. Calendar

Dates for compliance, including any record keeping requirements, are detailed in the applicable section for each element of the integrity management regulation.

Action Item	Reviews & Updates
Intentionally left blank	

[redacted] GTR0003442

12. Management of Change

12.1. Scope

Company has several ways to track changes in pipeline systems, procedural documentation and training. These existing methods are included in this section, along with procedures and forms used for Management of Change (MOC) for the Integrity Management Program.

12.2. Background

Management of change procedures are required to identify changes to pipeline systems and consider the impact of those changes on the integrity of the pipeline. Both major and minor changes, whether temporary or permanent, shall be documented, including:

- Technical
- Physical
- Procedure

12.3. Company Compliance

Company has an overall Management of Change Procedure to ensure that changes to programs are made for good reason with Company approval. The procedure outlines how changes are made, who makes the changes, and how those changes are passed on to individuals and organizations within the Company.

Processes that Company follows to ensure changes that could potentially affect the integrity of a pipeline are tracked and transmitted are described below and throughout this procedure. Company uses standard MOC forms in addition to the other documentation and procedures as described throughout this procedure. These forms are:

- **Integrity Management Program Change Form:** This form documents the changes and technical justification for all revisions to Risk Management Procedures (RMP's) (Appendix D)
- **IM Procedure Exception Request:** This form is used to document infrequent or "one-time" variances from the procedures described in this manual.
- **Testing Schedule or Tool Change Management Form:** Used to approve any changes in the assessment-testing schedule or tool selection.
- MAOP/MOP control form (part of UO standard DS0430/S4125): Used to document and control changes in MAOP and MOP.

Integrity Management Procedure Change Process

At least once each year, changes to RMP 6 will be reviewed and approved by the Vice President Gas Transmission and Distribution and CEO of Stanpac. Interim changes to RMP 6 as well as changes to all other RMP's will be reviewed and approved by the Manager of Integrity Management.

The objective for the integrity change management process is to ensure that qualified personnel are involved in the analysis, documentation, and approval of changes to the Baseline Assessment Plan. This process ensures:

- Appropriate reviews and approval are obtained prior to making a change to the program.
- Approved changes are documented in a timely manner.
- Changes to the program are communicated to the organization in a timely and accurate manner.

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The integrity change management process governs both major and minor documentation changes to the Integrity Management Program. Any employee can request changes to the program.

Changes to this procedure shall be communicated to all affected team members and training will be conducted as soon as practicable to ensure that work is performed to the latest requirements of the procedure. The communication shall be done within 5 days of approval and training shall be completed as soon as practicable.

The Integrity Management Change process requires any person with a change request to RMP-06 to submit the request to the Integrity Management Program Manager. If the change request is generated from the ECDA Program Manager, the ILI Program Manager or a member of the Integrity Management team, then the Integrity Management Program Manager can review the text changes directly.

For example, if the PSI Program Manager has changes to the Prevention and Mitigation section RMP 6 this procedure, the changes shall be submitted directly to the Integrity Management Program Manager. If the change request is generated from another source, then the Integrity Management Program Manager will review the proposed changes with the respective specialist. The final changes to the text will receive the concurrence of the technical specialist and be approved by the Integrity Management Program Manager and others as shown above.

12.4. Communication of Changes

Communication of all changes to Company system processes and procedures shall follow the guidelines as presented in Company's Communication Plan (see Section 14).

12.5. Use of Record of Change Form

The Integrity Management Program Change Form is used to track changes and updates to this procedure (Appendix D).It will accompany each RMP being routed for signatures as part of the approval process.

12.6. Results/ Documentation

Records for Management of Change associated with Company's Integrity Management Program will be maintained in the following location:

- GIS archives
- Risk Management (RM) files
- All changes to Risk Management procedures will be highlighted in the new version and all versions will be reviewed by the Integrity Management Program Manager and approved by the Manager of Integrity Management. The current version of procedure will be stored on the intranet and all versions will be stored in the Integrity Management library.
- Changes to the schedules for integrity assessments will be documented in GIS and the BAP. These changes will be approved as part of the audit change log review process and in the BAP. IMACS will be updated with all schedule changes to ensure proper tracking of proposed assessments. Assessment Mileage Table tracks completion dates of covered segments.
- Changes to Company Standards and Specifications will be made and documented through the existing MOC process for these documents.

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12.7. Technical Changes

As integrity assessments are completed, changes to operations for the system may possibly be needed, e.g. improved cathodic protection. These changes may flow both from the system operations to the Integrity Management Program and, as a result of determinations made by integrity management processes, from the Integrity Management Program back to the system. These technical changes will be noted in the "Long Term Integrity Management Plan" section of each pipeline .

As new technologies are developed, some of these are likely to be incorporated into the BAP. These shall be communicated to appropriate staff and procedures for any new technology documented. See the Procedural Changes subsection for more information about this process, including training requirements.

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12.8. Physical Changes

Physical changes occur throughout the lifetime of a pipeline and may include the inclusion of newly identified HCA segments. Company tracks these changes by patrols, maintenance and repair procedures, one-call activity reports and construction "as-builts".

These changes are documented as follows:

- During pipeline patrols or during normal maintenance. Standard Practice 4127 requires new construction to be identified and communicated to the Mapping department for incorporation into GIS. This notification is made on Appendix C of Standard Practice 4127 and a copy is to be sent to the Integrity Management Team for new HCA review. The Integrity Management team will document the results of each review in a note in the Mapping Department's New Construction Reports File.
- Whenever new construction or repairs are made to a pipeline, or any physical changes are made or observed, these changes are communicated via job as-builts or pipeline inspection reports and include a red-lined drawing, GPS coordinates and/or a sketch of the location. The applicable information from these reports is then entered into GIS. This review process will include changes to operation diagrams.

  Construction "as-builts" are posted to GIS as they are received by the Mapping department. Annually, the Integrity Mgmt Team will review GIS for all pipelines that have been newly constructed or relocated. These are easily identified by the "Date_Created", "Yr_Install" fields and the absence of a value in the "HCA_ID" field. HCA identification and update of the BAP shall be performed within one year of pipeline installation.

- Leak reports (Standard S4110) are updated in GIS either as they occur or during the semi-annual review for the IM Program metrics and OPS annual report. Leaks from backbone transmission lines are sent directly to Gas Transmission Mapping and are entered when they are received. Leaks on local transmission lines that are maintained by Division personnel are entered when the information is gathered for the IM Program metrics or OPS annual report.

  All GIS changes made to the following pipeline properties: Route, Trans_Def, Segment_No, MP1, MP2, MOP, OD, W_THICK, JntEff, SMYS, Long_Seam, Yr_Install, Test_Date, Test_Pressure, QA, COAT_TYPE, Asmt_Plan, Class_Present, HCA_ID, (these are column headings to the attribute table in the pipeline layer of GIS) and new records are noted in the Audit_Report changes Table on the SQL Server.

  Each change noted in the Audit_Reportchanges Table shall be evaluated by a Risk Management Engineer for potential impact on the Integrity Management Program. Impacts can include, but are not limited to:

  a. The creation or elimination of HCAs caused by changes to the PIR (caused by changes in OD or MOP) or pipeline alignment (caused by improved positional accuracy or a re-route),
  b. An increase in risk caused by changes in stress, test records, or other pipeline properties, (See RMP-01, RMP-02, RMP-03, RMP-04, and RMP-05 for a complete list of attributes that may affect risk) and
  c. A change in applicable threats caused by changes in stress or other pipeline properties such as Joint Efficiency Factor, Longitudinal Seam type, Year Installed, or coating type. (See Section 3 of this RMP for a complete list.)
  d. Potentially create a change in the Transmission Definition (see Appendix A) due to service to a large volume customer. As new pipelines are identified

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in the Audit Change Table, the review shall include consideration of whether the pipeline is being added to serve a large volume customer. If so, the review will ensure that the transmission definition and HCA identification will be applied appropriately.

Where pipeline changes impact existing HCAs or produce new HCAs, revisions shall be made to GIS and annually to the BAP.. The BAP Change Status Log shall also be updated to ensure the implication for the change is evaluated. GIS. IMACS, and Assessment Mileage Table shall also be updated to reflect changes to the BAP.

The Risk Management Engineer shall note acceptance of the pipeline change in the Audit_Report changes Table by adding his or her initials in the 'review_by' column and the date of his or her review in the 'review_date' column. Supplementary Notes regarding impact of the change on the Integrity Management Program shall be included in the Audit_Reportchanges Spreadsheet to explain the basis of acceptance. GIS changes should be evaluated within six months of posting in GIS. In no case shall the evaluation extend beyond one year. Based on a review by a qualified Risk Management Engineer, the following changes identified in the Audit_Reportchanges Table may be accepted on the annual update to the IM Program provided they are subsequently included into the annual revision of the BAP:

- Any change when the changed value is the same as assumed in the current BAP,
- Changes in Wall Thickness or Outside Diameter
- Changes in SMYS or joint efficiency,
- Changes in Year Installed
- Changes in Class,
- Changes in Coating,
- Changes in Seam Type
- Changes to MOP are managed through Standard Practice S4125;
- Changes in pipe alignment
- Changes in Assessment Plan or HCA ID.

HCA Identification Change Process

Company has the responsibility of incorporating newly identified HCAs into its Integrity Management Program within one year of identification. At the current time, Company will use the audit change log as the initial method of identifying new HCA's and then annually supplement that process with a review of changed parcel/land use information, new or changed pipelines, and field/First Responder reports to identify new or changes to existing HCAs. The field/First Responder reports and pipeline changes will be reviewed as they are submitted through GIS and the parcel/land use information will be reviewed annually.

See Section 17 New HCA Identification for more details.

12.9. Procedural Changes

Existing Management of Change to Company's standard operating procedures is handled by the following:

- Operations Manual
- Standards process

Currently, Company communicates changes and updates to procedures as they are available.

Revisions are published, unless the change is a compliance issue, as with IM Program. Those updates and changes are sent out to the divisions and other personnel immediately.

12.10: Change Communication

There are four different groups that need to be informed of changes that occur depending upon the type and significance of the change. These groups are:

- Integrity Management personnel
- Other Company personnel
- Office of Pipeline Safety (OPS)
- California Public Utilities Commission – Safety Branch (CPUC)

Integrity Management Personnel Whenever any changes occur to RMP-06, formal training will be documented for the affected Integrity Management Team, Direct Assessment Team and the In-Line Inspection Team, members.

Other Company personnel Whenever any changes occur affecting the patrolling requirements or data collection requirements for field personnel or contractors, a standup meeting shall be held to review the changes.

Office of Pipeline Safety – Within 30 days of making a change that substantially affects the program's implementation or significant change to the program or schedule, the Company shall notify OPS of the change, the reason for the change and any actions taken to ensure the safety of the public is not compromised. Examples of significant changes include the following:

- Merger of Companies or major acquisition of a transmission pipeline system.
- Determination of susceptibility to SCC when previously considered unsusceptible.
- Introduction of an assessment methodology not previously used.
- Abandoning an assessment methodology previously planned for use.
- A change in the HCA mileage by 10% or more in any calendar year.

In addition, when changing a high risk pipeline's scheduled assessment from "the first five years" to "the second five years", the Company will notify OPS of the change, the reason for the change and any actions taken to ensure the safety of the public is not compromised.

Notifications must provide enough information for OPS to understand the reason for deviation/change from the actions specified in the program. When a specific pipe segment is affected, the notification must also include information about the affected pipe segment and HCA. Notifications must also include the name, title, telephone number, and e-mail address of the Manager of Integrity Management, who may be contacted if additional information is needed.

California Public Utilities Commission Notification to the California Public Utilities Commission shall be submitted as shown for the Office of Pipeline Safety. In addition, the Company will provide an annual report that will document progress and includes the current version of the current Risk Management Procedures.

Additional information concerning notification to regulatory officials can be found in Section 14 (Communication Plan) and Section 15 (Notification to Authorities).

[redacted] GTR0003448

12.11. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
Not applicable			
WP 4125-04	Uprate Procedure	As needed	Technical Library

12.12. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Integrity Management Program Change Form	Appendix D
IM Program Exception Request Form	Appendix G
Testing Schedule or Tool Selection Change Form – to be developed by Integrity Management Program Manager by 12/05	Intentionally left blank
Audit Report Change Log	SQL Server

12.13. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Vice President of Gas Transmission and Distribution/President and CEO of StanPac	Sr. Vice President of Engineering and Operations	Annually approves RMP-06
Manager of Integrity Management	Director of Integrity Management and Technical Support	Reviews and approves all RMP changes.
Gas Transmission Estimating and Mapping Supervisor	Manager of Engineering Support Services	Ensure timely updates of GIS with construction as-builts, pipeline inspection reports, leak reports, new construction reports and MAOP changes
Integrity Management Program Manager	Manager of Integrity Management	Updating and communicating changes to RMP 01, 02, 03, 04, 05 06 and 08.. Responsible for authorizing and documenting changes to assessment schedules and ensuring communication to proper authorities.
DA Program Manager	Manager of Integrity Management	Updating and communicating changes to RMP-09. Seek authorization for changes to Direct Assessment schedules and obtain authorization from Integrity Management Program Manager. Training of and annual review with Direct Assessment team about RMP-06 and RMP-09.
ILI Program Manager	Manager of Integrity Management	Updating and communicating changes to RMP-11. Seek authorization for changes to In-Line inspection schedules and obtain authorization from Integrity Management Program Manager. Training of and annual review with In-Line Inspection team about RMP-06 and RMP-11

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13. Quality Assurance

13.1. Scope

192.911

B31.8S

The regulation points to B31.8S for guidance when creating a Quality Assurance (QA) plan. According to Section 12 of B31.8S, quality control is defined as "documented proof that the operator meets all the requirements of their integrity management program." This Section describes Company QA measures to verify the implementation and effectiveness of the IM Program.

13.2. Background

B31.8S 12.1

B31.8S 12.2

B31.8S Section 12 says that pipeline operators with an existing quality control program that meets or exceeds the following requirements can incorporate the integrity management program activities within their existing plan.

(a) Requirements of a quality control program include documentation, implementation and maintenance. Six activities are usually required:

(1) Identify the processes that will be included in the quality program.

(2) Determine the sequence and interaction of these processes.

(3) Determine the criteria and methods needed to ensure that both the operation and control of these processes are effective.

(4) Provide the resources and information necessary to support the operation and monitoring of these processes.

(5) Monitor, measure, and analyze these processes.

(6) Implement actions necessary to achieve planned results and continued improvement of these processes.

(b) Specifically, activities that should be included in the quality control program are as follows:

(1) Determine the documentation required and include it in the quality assurance program. These documents shall be controlled and maintained at appropriate locations for the duration of the program. Examples of documented activities include the BAP, LTIMP's, Assessment reports, and Root Cause Analysis reports. . (See Procedures sections.)

(2) The responsibilities and authorities under this program shall be clearly and formally defined. (See Roles and Responsibility section.)

(3) Results of the integrity management program and the quality control program shall be reviewed at predetermined intervals, making recommendations for improvement.

(4) The people involved in the integrity management program shall be competent, aware of the program and all of its activities and shall be properly trained to execute the activities within the program. Documentation of such competence, awareness and qualification, and the processes for their achievement, shall be part of the quality control plan.

(5) The operator shall determine how to monitor the integrity management program to show that it is being implemented according to plan and document these steps. These control points, criteria and/or performance metrics shall be defined.

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(6) Periodic internal audits of the integrity management program and its quality plan are recommended. An independent third-party review of the entire program may also be useful.

(7) Corrective actions to improve the integrity management program or quality plan shall be documented and the effectiveness of their implementation monitored."

13.3. Company Compliance

Company uses quality assurance checks to confirm that the program addresses pipeline system integrity issues. Such quality assurance includes periodic analysis of data to promote continual performance improvement and regular monitoring of the Program's implementation.

The data analysis includes an annual review of pipeline incidents and once each calendar year SME steering committees meet to discuss recommended changes to existing Risk Mgmt Algorithms.
Program compliance is monitored by monthly reporting of assessments completed compared to the assessments planned in the Baseline Assessment plan, and periodic audits of the Integrity Management Program processes and procedures.

The specifics are detailed in the following sub-sections.

13.4. Performance

Regular reporting of assessment completions helps present the status of integrity goals in an objective manner and enables the Company's upper management to be aware of non-compliance with the mileage commitments in the Baseline Assessment Plan.

On a quarterly basis, the Integrity Mgmt Program Mgr collects the miles of DA assessments completed through Phase 3 and ILI assessments, and reports to the Vice President of Gas Transmission and Distribution/CEO of Stanpac.

13.5. Preventive Measures

Company monitors surveillance and preventive activities, and these indicate how well Company is implementing the various integrity management elements. The required semi-annual surveys are scheduled in PG&E's Work Management software and these records are reviewed during PG&E's internal regulatory compliance audits.

13.6. Incident Measures

Incident measures determine if goals for fewer incidents and less threat to people and the environment are being met. These are documented in Incident reports and the annual statistics are summarized by the PSIP Manager and reported in the CPUC Integrity Risk Mgmt Annual report.

13.7. Data Verification

All data used in risk assessment shall be verified and checked for accuracy on a periodic basis. A qualified individual within Company or an outside expert shall do verification of data. RMP-01 explains the sources and methods of ascertaining data for risk assessment.

[redacted]

13.8. Internal/ External Audits

Either an internal or an external audit will be performed every other calendar year to ensure compliance with our own procedures and to ensure those procedures meet regulatory requirements. .

External Audits: Periodically, Company shall undertake an external audit by a qualified government or industry source. The external audit will examine IM Program performance against regulatory requirements and/or other companies. This audit will measure how the Company's Integrity Management Program and activities are progressing in relation to the regulation and other companies in the industry.

13.9. Corrective Action

If the Company Integrity Management Procedures are found through this Quality Assurance process to be lacking in any aspect, changes to the Integrity Management Program shall be implemented according to the Management of Change (MOC) process. Such changes shall be documented according MOC rules, and the effectiveness of those changes shall be monitored via the Quality Assurance process.

13.10. Qualified Company Personnel

Company personnel involved in the Integrity Management Program shall be fluent in the program and its activities, and properly trained to execute those activities.

Company has existing procedures to document the qualifications of its personnel, which are detailed in the qualifications and training section of each procedure.

The specific personnel that Company must have to carry out an Integrity Management Program are outlined in the Roles and Responsibility sections in each element of this Plan.

13.11. Contractor Qualification

B31.8S 12.2

The DA procedures and ILI procedures shall specify the process utilized to verify contractors' qualifications to perform the work. Generally, these are specified in the Contract Specifications for each job.

13.12. Results Distribution

After Integrity Management Program reviews and audits, the results will be reported to VP Gas Transmission and Distribution, Senior Director of Gas Engineering, Director of Integrity Management and Technical Support, the Manager of Integrity Management, the Manager of Pipeline Engineering, and the program managers for ILI, Direct Assessment and Integrity Management.

[redacted]

GTR0003452

13.13. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
ILI Program Manager	Sr. Manager Technical Services	Monthly reporting of assessments and metrics
DA Program Manager	Manager of Integrity Management	Monthly reporting of assessments and metrics
Integrity Management Program Manager	Manager of Integrity Management	Monthly reporting of assessments completed. Risk calculation reviews, SME Steering Committee meetings. CPUC Risk Mgmt report, Scheduling audits
Public Safety Information Program (PSIP) Manager	Supervisor of Gas System Integrity	Incident metrics

13.14. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Review of Pipeline Incidents	Annually reported to CPUC
Internal or External Audit	Every other calendar year
SME Steering Committee Meetings	Every calendar year
Monthly reporting of assessments completed	Monthly
Validation of Risk Calculations	New system wide risk calculations

[redacted]

GTR0003453

14. Communication Plan

14.1. Scope

This section contains all cross-communication among parties involved in integrity management and operations.

14.2. Background

[illegible]
B31.8S 1

The regulation states that a communication plan must include the elements of B31.8S Section 10, and procedures for addressing safety concerns raised by:
(1) OPS: and
(2) A State or local pipeline safety authority when a HCA is located in a State where OPS has an interstate agent agreement.

14.3. Company Compliance

B31.8S 10 and 10.1

This Company communications plan is intended to keep appropriate Company personnel, jurisdictional authorities and the public informed about the Company's Integrity Management Program. The information may be communicated as part of other required communications.

Communications shall be conducted as often as necessary to ensure that appropriate individuals and authorities have current information about the operator's system and their integrity management efforts. Communications shall take place periodically and as often as necessary to communicate significant changes to the integrity management program.

Some of the information is communicated routinely. Other information may be communicated upon request.

[redacted]

14.4 External Communication

B31.8S 10.2 and 10.3

Information will be communicated to the following groups of people outside of the Company. (The Company does not necessarily limit its external communications to these groups):

1. Landowners and tenants along the rights-of-way
2. Public officials other than Emergency Responders
3. Local and regional Emergency Responders
4. General public
5. Regulatory Agencies

The following describes the types of communication processes that have been established for each of the above groups.

Landowners and tenants along the rights-of-way. Prior to performing integrity assessments (DA, smart pigging, etc.), as part of the integrity assessment process, all the landowners and tenants inside the designated High Consequence Area will be notified. Most of these notifications will occur and be documented in the job files by letter. One on one communications will occur while gathering data in the field, and any and all questions will be addressed. Additional notifications will occur if direct examinations are required that could in any way disrupt normal landowner activities. See Section 9.5 for additional notifications.

Public Officials other than Emergency Responders. Prior to performing integrity assessments (DA, smart pigging, etc.) all permitting agencies, including all applicable city, county, and federal agencies, will be notified as to the objectives and details of the specific assessments to be performed. Any and all concerns will be addressed. Documentation for this communication will be part of the permit package, and any additional correspondence will be included in the job file.

Local and regional Emergency Responders. As part of the Company's Public Safety Information Program (PSIP), biennially each operations and maintenance District holds an informational "open house" meeting with all first responding emergency agencies. These meetings are documented via the PSIP program documentation process. Integrity Management activities will be fully communicated and discussed at these meetings and the Emergency Responders will be queried about HCAs near Company pipelines.

General Public. Any concerns or questions raised by the general public will be promptly addressed.

Regulatory Agencies. As required by 49 CFR part 192 Subpart O, the Company will submit semi-annual performance metrics to both DOT/OPS and to the CPUC. Additionally, if concerns about the Integrity Management Program are raised by either the DOT/OPS or the CPUC, the System Integrity Manager shall provide a written response providing the company's assessment of the concern, actions that will be taken to address the concern, and schedules for completing those actions. The written response (or email) shall be submitted as required by the Regulating Agency.

[redacted]

GTR0003455

14.5. Crisis Communication

The Company (GSM&TS) Emergency Plan Manual contains specific communication procedures and requirements in the event of a crisis. Crisis would include natural disasters affecting public safety or supply, security threats, deaths or accidents, or any other event that could adversely impact the Company's ability to provide safe and reliable natural gas transmission service, such that it would immediately impact the public or the environment. All key stakeholder contact information, including employees, agencies, corporate security, first responding agencies, etc. are listed in these procedures. Procedures for communication with the media are included in these procedures.

Company standard 4413 provides specific requirements for what incidences require regulatory or agency reporting, who to report to, and the required reporting timeframes. This standard fully complies with 49 CFR Part 192 requirements and includes telephonic reports to the CPUC, Gas Quarterly reports and Safety Related Condition reports. During integrity assessments the Company will ensure this standard is followed to ensure proper reporting of any serious conditions or incidents that may occur.

14.6. Internal Communication

The Company will regularly communicate the status and results of the gas transmission Integrity Management activities. Each calendar year, the Vice President, Gas Transmission and Distribution will author and distribute a general compliance email to the gas transmission organizations, which will summarize the general results and activities associated with the Integrity Management Program.

Regular communication at all levels will occur during the year. Email, tailboards, and meetings will provide the mechanisms for the bulk of this communication. The intent is for every gas transmission employee to be aware of and understand the basics of the Integrity Management initiative. .
A Company wide web site is maintained within PG&E's intranet system to promote Pipeline Integrity and Risk Management related information exchange. The Integrity Management Program Manager is responsible for posting the mission /vision and related informational updates, such as system wide risk statistics and mitigation efforts, a summary of the incidents occurring on the pipelines and the current CPUC RM Annual Report.

When employees in the field discover potential hazards, employees can use the web site to notify the Risk/Integrity Management team of the concern via the on-line "Pipeline Risk Evaluation Form. If immediate action is required, the Integrity Management Program Manager will champion the necessary immediate action.

14.7. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
RMP-9 ECDA Procedure (Landowner Notification)	RM Files
RMP-11 ILI Procedure (Landowner Notification)	RM Files
Company Gas Emergency Plan	Technical Information Library
Pipeline Safety Manual	RM Files
First Responder Manual	RM Files
S4413 CPUC and DOT Reportable Incidents	Technical Information Library

[redacted]

14.8. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Manager of Integrity Management	Director, Integrity Management & Technical Support	Overall Integrity Management Program Compliance
Integrity Management Program Manager	Manager of Integrity Management	Integrity Management Program
DA Program Manager	Manager of Integrity Management	Direct Assessment Program
ILI Program Manager	Manager of Integrity Management	ILI Program

14.9. Calendar

The following dates address compliance requirements for this element.

Action Item	Reviews & Updates
VP Authorization of RMP-06	Each calendar year
CPUC- Risk/Integrity Management Report	Annually
VP IMP internal communication to org. about IMP	Each calendar year
PSIP Communications to First Responders	Biennially
Metric Reporting to OPS and CPUC	Semi-Annually (02 & 08)
Integrity Management Program Communications	Semi-Annually
Integrity Management Performance Metrics (Internal)	Monthly
Update Company Integrity Management Website	Each calendar year
Update General Public Communications Form	As needed
Distribute General Public Communications Form	As needed

[redacted]

15. Notification of Authorities

15.1. Scope

Notification of authorities is required at various times during the integrity management process. Company may also be requested to submit the risk analysis or integrity management program. This Section presents the details and procedures for those notifications.

15.2. Company Compliance

Company makes notifications and reports to OPS and the California Public Utilities as part of it the implementation of the integrity management regulations. These include:

- Submittal of risk analysis or integrity management program when requested
- Use of other technology as an assessment method
- Significant deviation or change from assessment schedule or program (see section 12.10)
- Inability to meet remediation schedule and to temporarily reduce operating pressure
- Semi-annual performance metrics
- Where the Company believes it must deviate from the assessment intervals as called for in section 192.943, a waiver shall be sought from the Secretary of Transportation in accordance with 49 USC 60118(c). That section of the code allows the Secretary to waive compliance with this requirement on terms the Secretary considers appropriate, if the waiver is not inconsistent with pipeline safety. The Secretary shall state the reasons for granting a waiver and may act on a waiver only after notice of an opportunity for a hearing. Copies of any waiver requests to the Secretary shall also be sent to the CPUC for their information.

15.3. Processes for Compliance

OPS Notifications

The table below lists the acceptable methods of communications with OPS. Company's general policy is to use on-line notification.

Type of Communication:	Method:	Contact Information
Notifications:	**Mail:**	Office of Pipeline Safety Pipeline and Hazardous Materials Safety Administration U.S. Department of Transportation Information Resources Manager PHP-10 1200 New Jersey Ave., SE Washington, DC 20590-0001
	Facsimile	Information Resources Manager (202) 366-7128
	Online:	Integrity Management Database (IMDB) Web site at *http://primis.rspa.dot.gov/gasimp*
Reports:	**Mail:**	Office of Pipeline Safety Pipeline and Hazardous Materials Safety Administration U.S. Department of Transportation Information Resources Manager PHP-10 1200 New Jersey Ave., SE Washington, DC 20590-0001
	Facsimile	(202) 366-7128
	Online Reporting System:	OPS Home Page at *http://ops.dot.gov*

[redacted] GTR0003459

State Authority Notifications

California is the only state in which the Company has pipelines. The Company's general policy is to use mail to notify the state authority.

STATE OF:	**California**	
AUTHORITY:	**Public Utilities Commission – Safety and Reliability Branch**	
Type of Communication:	**Method:**	**Contact Information**
Notifications:	**Mail:**	[redacted] Chief [redacted]
	Facsimile	
	Online:	
Reports:	**Mail:**	[redacted] Chief [redacted]
	Facsimile	
	Online Reporting System:	

15.4 Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager of Integrity Management	Semi-annual report, CPUC Annual Risk Management Report of any significant changes to the Integrity Management Program.

[redacted]

GTR0003460

16. Environmental and Safety Measures

16.1. Scope

This section of the Integrity Management Program covers environmental and safety risks, and the steps taken by Company to ensure that the baseline assessment is being conducted in a manner that minimizes those risks.

16.2. Background and Compliance

192.919 (e)

The Company has in place an extensive safety and environmental protection program. In addition, procedures are being developed to address excavation issues of transmission pipelines and the Company has a number of environmental procedures in place to address spills and cleanup in an environmentally safe manner..

16.3. Procedures

Title	Location
P-002 E-Screen and BMPs Procedure and associated exhibits	Environmental Services Website
USP-22 Safety and Health Program	Safety Health and Claims website
USP-17 Environmental Management System	Guidance Document Library Company Intranet
PG&E Utilities Operation Guideline G14413	

16.4. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Intentionally left blank	

16.5. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to: Responsibilities
As noted in each reference procedure	

16.6. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Revise Section 16	As Necessary

[redacted] GTR0003461

17. New HCA Identification

17.1. Scope

This section covers processes for newly identified High Consequence Areas.

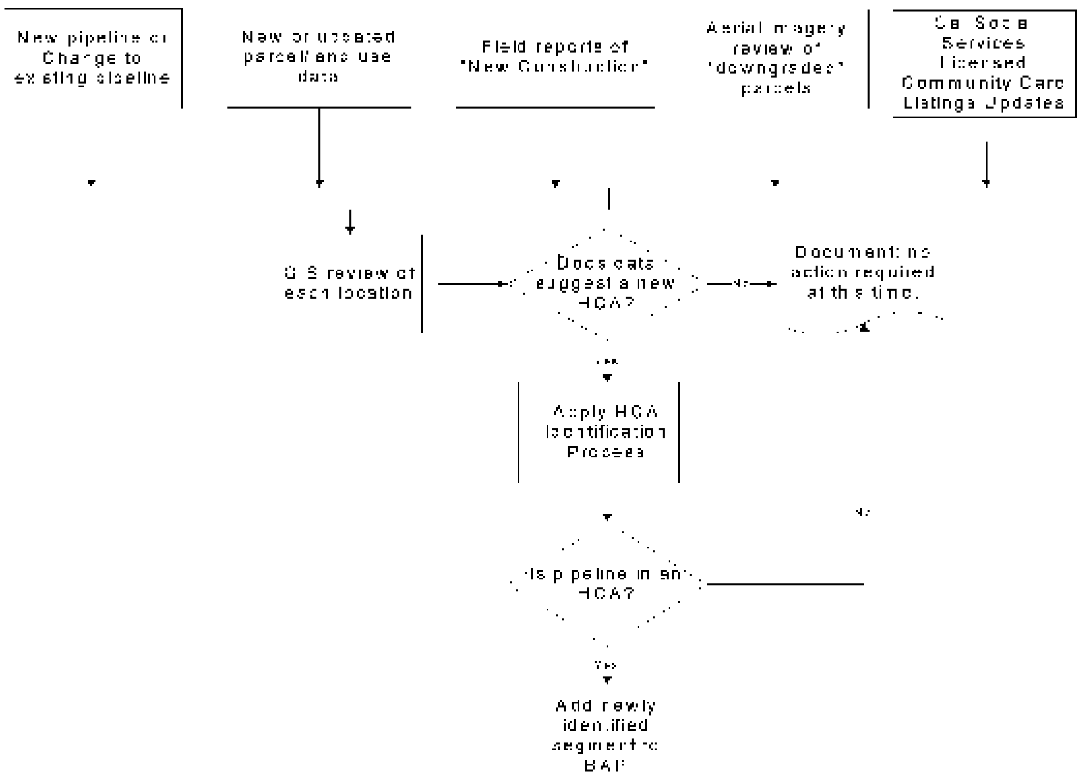
17.2. Background

There are nine causes for a newly identified High Consequence Area:

1. New installation or changes to an existing pipeline
2. New or updated parcel/land use information
3. Data that suggests an HCA under development (Field "New Construction" reports)
4. Updated aerial imagery
5. Surveys to verify identified sites (Field Engineer Reports)
6. Public Official Notification
7. Surveys to verify identified sites (Field Engineer Reports)
8. Information from first responders and public officials
9. New licensed community care facility

The New HCA Identification flowchart shows the high-level process for new HCA identification.

New HCA Identification Process



17.3. Company Compliance

192.935
192.921

Newly identified High Consequence Areas go through the same integrity management processes as all other HCAs. They must be incorporated into the Company baseline assessment plan within one year of discovery, and assessment must be completed within 10 years of identification.

Information about possible new HCA areas comes from different sources. Some of these may include (but are not limited to):

- Routine patrolling
- New construction drawings and reports
- New parcel data
- Updated land use designations
- New information from Ca. Social Services Licensed Community Care Listing
- Procedure to update class locations
- Surveys to verify identified sites (Field Engineer Reports)
- Aerial imagery review of parcels whose structure count or identified site designation was downgraded because historical aerial photography revealed the structures were out of the impact zone
- Information from first responders and public officials such as the California Social Services Licensed Community Care listing

17.4. New Pipeline and Changes in Existing Pipeline

New pipelines or changes in existing pipeline operating conditions could create HCAs. The following data shall be reviewed to identify these changes:

- Annually a GIS review will be performed to assess all pipeline segments newly installed or reconstructed
- Annually review GIS for pipelines with pressure tests in the previous year. This review will verify that existing processes have notified the Integrity Management team of all pipeline operating changes
- As they occur, all MAOP/MOP changes shall be reviewed. The Integrity Management team is cc'd on all changes.

The process detailed in paragraph 1.3 will be followed to determine if the new pipeline route or impact zone creates an HCA. All newly identified HCAs will be added to a revised Baseline Assessment Plan and scheduled for assessment within 10 years of the HCA identification.

17.5. Data Suggesting a New HCA

The following data will be reviewed (as specified) to determine if new HCAs exist:

- Annually review all parcels whose land use codes have changed
- Annually review the most current aerial photography for all parcels with downgraded "Structures" or "Id Sites" to determine if new structures or expansions to existing structures have changed the parcel's designation
- Annually review Ca. Social Services Community Care Listing
- Annually review all "Notice of New Construction" from the previous year to capture any "Identified Sites" discovered by field personnel.
- Biennially review input from First Responders
- Every 5 calendar years do a complete review of transmission pipelines to re-verify HCA identification (using the latest aerial imagery).

[redacted] GTR0003463

17.6. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

	Description	Update Schedule	Location
RMP-08	Identification, Location and Documentation of High Consequence Areas (HCA's)	As necessary.	RM Files

17.7. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
RMP-08	RM Files
Land Use Codes for Counties	RM File 15
PG&E Parcel Data Feature Class Descriptions from Cadastra	RM File 15

17.8. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager of Integrity Management	Ensure all HCA reviews occur
PSIP Manager	Manager of Integrity Management	Gathering First Responder input
GIS Team Lead	Integrity Management Program Manager	Obtaining the licensed community care listing from California Social Services

17.9. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates
Land use code review	Annually
Review parcels with land use code change	Annually
Ca. Social Services Licensed Comm. Care Listing	Annually
New Pipeline Construction	Ongoing
Changed Pipeline Operating Conditions	Ongoing
Notice of New Construction	Ongoing
First Responder input	Biennially
MAOP/MOP changes	As they occur
Complete HCA Identification Review	Every Fifth Year

18. Exception Process

18.1 Exceptions

It is expected that all requirements of this procedure be met in conducting the Integrity Management Program. However, when this is not possible, then exceptions can be made by obtaining approval, and documenting the exceptions, as prescribed in this section. Note: If it is the intent to take exception to a "shall" stated in either the DOT Integrity Management Rule then a waiver must be obtained from OPS.

18.2 Objective

The purpose of this section is to provide control and documentation of exceptions taken of this procedure. This control and documentation is to maintain the integrity of conducting an the Integrity Management Program, to continuously improve the process by providing feedback, and to have an auditable trail and be in compliance with the procedure at all times.

18.3 Exception Requirements

The following process is required for taking an exception with this procedure. It shall be documented on the form provided in Appendix G, Exception Report:

- Section of Procedure: State the specific paragraph number where the exception is being taken. Briefly state in your own words the requirements of the paragraph.
- Alternative Plan: State what is proposed instead of what is required in the procedure.
- Reason: Provide the reason the exception is needed.
- Recommendation: Indicate if it is recommended to change the procedure or that this exception is project specific.
- Approval: Obtain approval from the Manager of Integrity Management or his/her designate prior to acting on the exception.
- Documentation: Document the above steps on the form provided in Appendix G, Exception Report. Place all exception reports in the RMP File 22 – Program Exceptions.
- Exception to CPUC/OPS "shall" statements in the Integrity Management Rule or referenced standards require waiver be obtained from OPS prior to Exception Approval by the System Integrity Manager.

[redacted] GTR0003465

Appendix A. Transmission Line Definition

CODE INTERPRETATION

Subject 49CFR Section 192.3 Definitions….Transmission Lines

Problem In order to consistently respond to the annual DOT and FERC data requests and to evaluate CGT pipeline maintenance and operation compliance with DOT Pipeline Safety Regulations (49CFR192), GSM&TS needs to determine which of its pipelines should be classified as transmission and which should be classified as distribution.

Code Language

Transmission Line means a pipeline, other than a gathering line, that:

(a) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;
(b) Operates at a hoop stress of 20 percent or more of SMYS; or,
(c) Transports gas within a storage field

A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

OPS Code Interpretations

Transmission Line:

11/30/78 "Since the term 'transmission line' was used in those notices and the notices were, in general, based on the U.S.A.S. B31.8 Code (1968 ed.), we agree that the notices must have been drafted with the B31.8 definition of 'transmission line' in mind….Since the term 'transmission line' in Part 192 is intended to have the same meaning as that in the B31.8 Code…."

08/09/88 – "A pipeline, a piece of which is operated at 20 percent or more of SMYS, is classified as a transmission line at least to the terminus of the last segment operating at 20 percent or more of SMYS.

05/30/91 "(ends at)..the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale."

Distribution Center:

Per OPS interpretations on 11/30/78 and 5/30/91 a distribution center is:
"..the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale."

PG&E application of the definitions/interpretations

In addition to the OPS code interpretations; GSM&TS must document the following internal definitions in order to document the classifications of the pipelines it operates:

Maximum Operating Stress (MOP):

The lowest MAOP in a pipeline segment is considered by PG&E to be the MOP. The MOP is used to calculate the hoop stresses in a pipeline segment and determine the percent of SMYS for each unique pipe section in the segment.

[redacted] GTR0003466

Numbered Lines and DFMs:

Historically GSM&TS' pipelines have been segregated into two classifications; Numbered Transmission Lines, and DFMs. These classifications reflected the ASME B31.8 function of the pipelines and the FERC accounting used to construct them. Numbered Transmission lines were considered transmission, and DFMs were considered functionally distribution. DFMs operating over 20% SMYS were accounted as distribution but maintained as transmission to meet the CFR 49 definition.

Distribution Center:

CGT will consider the distribution centers to be "points" where gas flows into non transmission DFMs (operating under 20% and primarily delivering to customers who have purchased it for consumption), or district regulating stations that feed distribution mains and services.

Large Volume Customer:

CGT defines large volume customer as a customer whose usage qualifies as a noncore end use customer according to Tariff schedule G-NT. To qualify, a customer must: 1) have an average historical use through a single meter of greater than 3,000,000 therms/yr for the previous three years and a historical use of greater than 2,500,000 therms/yr in the most recent 12-month period or be able to document an increase in gas use due to permanent changes in the operations of the Customer's facility that will cause usage to exceed 3,000,000 therms/year.

Interpretation

Unless a review determines that the definitions have been incorrectly applied, the following criteria will be used to determine if a pipeline will be classified as transmission. Misapplications of the criteria will be documented at the end of this interpretation. The criteria are as follows:

a) Transports gas…
   - Pipelines historically numbered and classified as transmission to meet CFR 49 reporting and maintenance requirements.
   - All pipelines directly connected to gas gathering lines
   - Pipelines primarily used to deliver gas to customers who purchase it for resale as opposed to customers who purchase it for consumption.
   - All pipelines, not downstream of a distribution center, whose primary customer is a large non-core customer, even though it may be operating below 20% SMYS.

b) Operates at or above 20%...
   - All portions of pipelines that operate with a hoop stress at or above 20% SMYS or precede a portion that operates with a hoop stress at or above 20% SMYS.

c) All pipelines transporting gas within or from a gas storage field

Misapplication of PG&E's transmission line interpretation

A review was performed system-wide to determine if there were pipelines that had been incorrectly defined as DFMs or as numbered transmission lines. The interpretation was used to determine the correct classification. PG&E's GIS was updated to reflect the correct classification, but the pipeline number was not changed so that the link to historical documentation would not be lost. To date these misapplications are limited to: 119D, 126A, 126C, 126D, 137A, 137C and 137D.

[redacted] GTR0003467

Appendix B. Typical Pipe Data Element

Note: A description of each of the fields and the codes used shall be documented in the annual Systemwide Threat Analysis Key. (As an example for the 2004 five bay area counties, the key is contained in **\\Wabmterk01\Mapping\RiskMgmt\Integrity Management Plans\Threat Analysis\2004 Systemwide Risk Calc Values2 5 County.xls**

PIPE and ENVIRONMENT DATA

IMA# 002_0.00

Route 002

Source Route Source MP 0

Segment	142.5	MP1	76.19	MP2	76.46	Footage	1425

PIPE DATA							
Yr Installed	1/1/' 969	OD	26	Pipe Mat	X6C	Trans Def	T
Age	35.85	MOP	890	WT	0.322	SMYS	60000
Seam	DSAW	Jnt	1.000	%SMYS	59.89%	Class	1
Girth Weld	A	Girth Jnt	BUTT	Mech Coupling?		PIR	535
Pipe Manuf							
PT Date	1/1/' 969	PT Media	W	PT Dur	0	PT Pressure	1480
PT Age	35.85	Wrinkle Bend		Mech Cplg?		Strength	1486
Cond		DM Leaks		Product	NG	LDM	0
External Corrosion Considerations							
Type	HAA	Installed	1/1/1969	CIS Cond	F	Atom Cond	
ILI		CIS		ECDA		Yr of EC Leak	
AC/DC Int	M	Casing		Soil Res	0	LEC	32.9
Internal Corrosion Specific Considerations							
IC Threat Identified?		None					
SCC Specific Considerations							
Distance from nearest Compressor?	>20	SCC Incidents?	No	Stress > 60% SMYS?	No	Coating	HAA
Third Party Considerations							
Cover (GIS)	5	Cover (A-?)	0	Dig-In Mag		TP Leaks	
Line Mark		P Protect	S	Public Ed		LTP	14.2
Ground Movement Considerations							
Grnd Accel (X100)	40	Crossing		Erosion		Unstable Soil	
GM Mitigation						LGM	0
Consequence Considerations							
RR		Highway		HCA		Crit Facility	
Airport		Envir Area		HCA ID	I5		
Gas Load	-9	# Cust Out	-9	FSE	1	Wtr Xing	
IOE	0	IOR	18	IOP	16.71	COF	15.55
RISK Values							
LEC	32.9	LTP	14.2	LGM	0	LDM	0
LIC		LOF	14.82	IM COF	1.30	IM RISK	18.98
Past Assessment		I01					

[redacted]

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Appendix C. Intentionally Left Blank

Appendix D. RMP Change Form

Pacific Gas and Electric

Integrity Management Program
Change Form

Standard Pacific Pipelines Inc.

Changes for RMP- ________
Revision ________ Date______________

Attachment D to RMP-06
Page 94 of 99

Section Change	Reason for Change	Implication of Change

[redacted]

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Appendix E. Intentionally Blank

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[redacted]

Appendix F. LTIMP Checklist

Appendix F LTIMP Checklist

Category	Item	Checklist	Status	Notes
Data Gathering and Integration	A.1	Integrity Management data for the relevant pipeline segment(s) pulled from files and available for review with GIS data.		
	A.2	A and H Form Themes are visible during review		
	A.3	All past assessments identified, integrated in GIS, legendized appropriately, and visible for review while planning results (In Notes provide themes and location of themes)		
	A.4	Remediations are incorporated into GIS		
	A.5	Studies/Reports available on the section of pipe are available for consideration during review (In Notes Provide References) (Ensure that root cause reports are considered.)		
	A.6	Pipe Properties theme visible and legendized based on HCA_ID		
	A.7	Risk Theme loaded and available for consideration during planning		
	A.7.a	Theme of Pipelines identified by field as having a higher level of risk from third party damage loaded and visible (mag_loc)		
	A.7.b	Foreign Line Themes loaded and visible (In Notes provide themes used)		
	A.7.c	Geotechnical hazards loaded and fault theme, landslide, and erosion themes visible. (Other themes shall be made visible as appropriate.)		
	A.7.d	Electric Transmission Lines Theme loaded and Visible		
	A.7.e	Raillines Theme Loaded and Visible		
	A.8	USA Information loaded and available for consideration during planning		

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[redacted]

Appendix F LTIMP Checklist

Category	Item	Checklist	Status	Notes
	A.9	Aerial Photography is available and utilized during review.		
	A.10	Parcel Data Loaded and available for review to verify extent of HCA's		
	A.11	PIC Tool Results loaded and available for review to verify extent of HCA's		
Review / Analysis / Recommendations	B.1	Verify that the assessment covers the intended scope of assessment using appropriate tool. (Refer to GIS)		
	B.2	Verify that all of the necessary threats have been assessed. Note any threats requiring further assessment.		
	B.3	If ILI, check for Internal Corrosion damage reported. If damage reported and verified (ascertain if it exists), ensure that the route and segment are included in the BAP/IMACS/ and Threat Spreadsheets as an Internal Corrosion Threat. If applicable, scope out extent of threat application.		
	B.4	If ECDA, check for identification of Internal Corrosion threat/damage, SCC damage, and selective seam weld damage. If damage reported, ensure that the route and segment are included in the BAP/IMACS/ and Threat Spreadsheets as an Internal Corrosion Threat. If applicable, scope out extent of threat application.		
	B.5	Using GIS, pan through integrated data, analyze, and establish desired prevention and mitigation measures. In addition to the data integrated and reviewed in Items A.1 to A.14, ensure that the following risk mitigation strategies are considered:		
	B.5.a	While panning, review HCA to ensure that it looks appropriate.		
	B.5.b	Improved cathodic protection – Recoat, addition or alteration of rectifiers, anodeflex, etc.		
	B.5.c	Improved resistance to Third Party damage (Improved Line Marking, Landowner Notification, additional public awareness efforts increased cover, thicker pipe, relocation)		
	B.5.d	Implementing additional inspection and maintenance programs.		
	B.5.e	Cyclic fatigue		

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Appendix F LTIMP Checklist

Category	Item	Checklist	Status	Notes
	B.5.f	Installation of Automatic Shut-off Valves or Remote Control Valves		
	B.5.g	Installation of computerized monitoring and leak detection systems		
	B.5.h	Providing additional training to personnel on response procedures		
	B.5.i	Conducting drills with emergency responders		
Determine Reassessment Schedule	C.1	Calculation of reassessment interval based on data integration as shown in A.1 to A.14		
	C.2	Calculation of reassessment interval based on risk		
	C.3	Calculation of reassessment interval based on threats		
	C.4	Calculation of reassessment interval based on § 4.9 of RMP-06		
	C.4.a	ILI -		
	C.4.b	ECDA -		
Documentation	D.1	Description of process completed and incorporated into project files.		
	D.2	Description of recommendations for preventive and mitigative measures. Rank priority of measures based on risk.		
	D.3	Description of recommended additional investigation.		
	D.5	Update of IMACS to track that preventive/mitigative and investigative efforts are completed and completed as risk indicates. (Pipelines that have been identified as similar and requiring preventative and mitigative measures shall also be entered into IMACS.)		
	D.6	BAP / GIS / IMACS / and Threat Spreadsheet revised to reflect next assessment plan.		
	D7	Consideration to Prevention and Mitigative measures to pipeline segments that may have similar material and environmental characteristics.		

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Appendix G. Exception Report

Integrity Management_Exception Report

DATE OF REPORT:
EXCEPTION REPORT NUMBER: ________

ROUTE NUMBER:____________________

MP:

Procedure and Paragraph Number of Exception:

Requirements of paragraph (Your own words): ____

____
____

Alternative Plan: ____
____

____
____

Reason for Exception: ____

____
____

____

Recommendation: Should the procedure be changed? ☐ YES ☐ NO
COMMENTS: ____
____
____

Does this waiver require CPUC/OPS Notification: ☐ YES ☐ NO

Risk Management Engineer: ______________________________ **Date:** __________

Reviewer: ______________________________ **Date:** __________

PROGRAM MANAGER: ______________________________ **DATE** __________

MANAGER SYSTEM INTEGRITY: **DATE**

[redacted]