Docket No. SA-534

Exhibit No. 2-AU

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C.

EXCERPTS FROM THE
PG&E INTEGRITY MGMT PLAN
RMP-06, RMP-10, RMP-11 AND RMP-13

(164 Pages)

PACIFIC GAS AND ELECTRIC COMPANY
San Bruno Gas Transmission Line Incident
Data Response

PG&E Data Request No.:	NTSB_003-001-S8		
PG&E File Name:	San Bruno GT Line Incident_DR_NTSB_003-001-S8		
Request Date:	September 11, 2010	Requesting Party:	NTSB
Date Sent:	February 14, 2011	Requestor:	NTSB (Rick Downs)

QUESTION 1

Information supporting compliance with CFR 192 in the following sections of code:

h. 192-905 - How does an operator identify a high consequence area (HCA)?

i. 192.907 - What must an operator do to implement subpart (O)?

ANSWER 1 – SUPPLEMENT 8

h. and i. - Please see attached Integrity and Risk Management Programs (RMP-01 through RMP-06 and RMP-08 through RMP-13). These RMPs were produced without redactions and clean copies were provided on January 28, 2011.

PG&E agrees to waive privilege with respect to the requested documents and additional copies are attached.

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.

			Prepared by	Approved by		Approved by	Approved by
Rev. No.	Date	Description	Integrity Management Program Manager	Manager, System Integrity		Director, GSM&TS	Vice President – Gas Transmission and Distribution, President/CEO, Standard Pacific Pipelines, Inc.
0	12/9/04	Initial Issue	CMW4	ADE1		FT1	RTHc
1	10/14/05	See Change Forms for detailed descriptions	DJC9	CMW4		FT1	RTHc
2	1/25/07	See Change Forms for detailed descriptions	WJM8	CMW4		SW1	RTHc
			Prepared by	Approved by		Approved by	Approved by
Rev. No.	Date	Description	Integrity Management Program Manager	Director System Integ. & Gas Matters		Director, Gas Engineering	Vice President – Gas Transmission and Distribution, President/CEO, Standard Pacific Pipelines, Inc.
3	12/30/08	See Change Forms for detailed descriptions	WJM8	RPF2		GECj	RTHc
			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.
4	1/26/10	See Change Forms for detailed descriptions	WJM8	SEBE	RPF2	GECj	RTHc
	.	.	Prepared by	Approved by	Approved by		
Rev. No	Date	Description	Risk Management Engineer	Integrity Management Program Manager	Manager, Integrity Management		
5		See Change Forms for detailed descriptions					

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 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.

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.

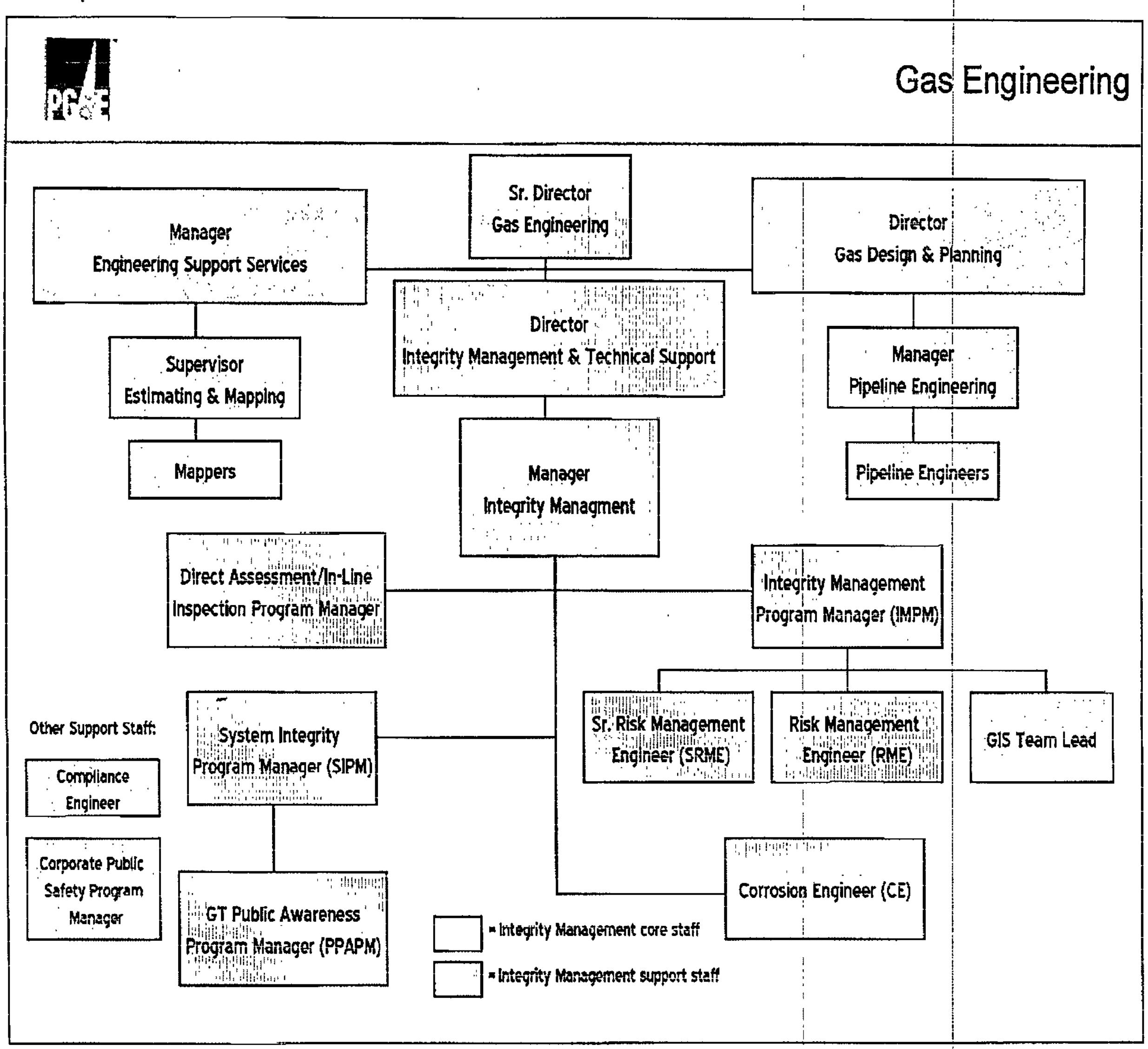
Senior Director of Gas Engineering: Shall have authorization to approve BAP.
Training: Review of RMP-06 during approval process.

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



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

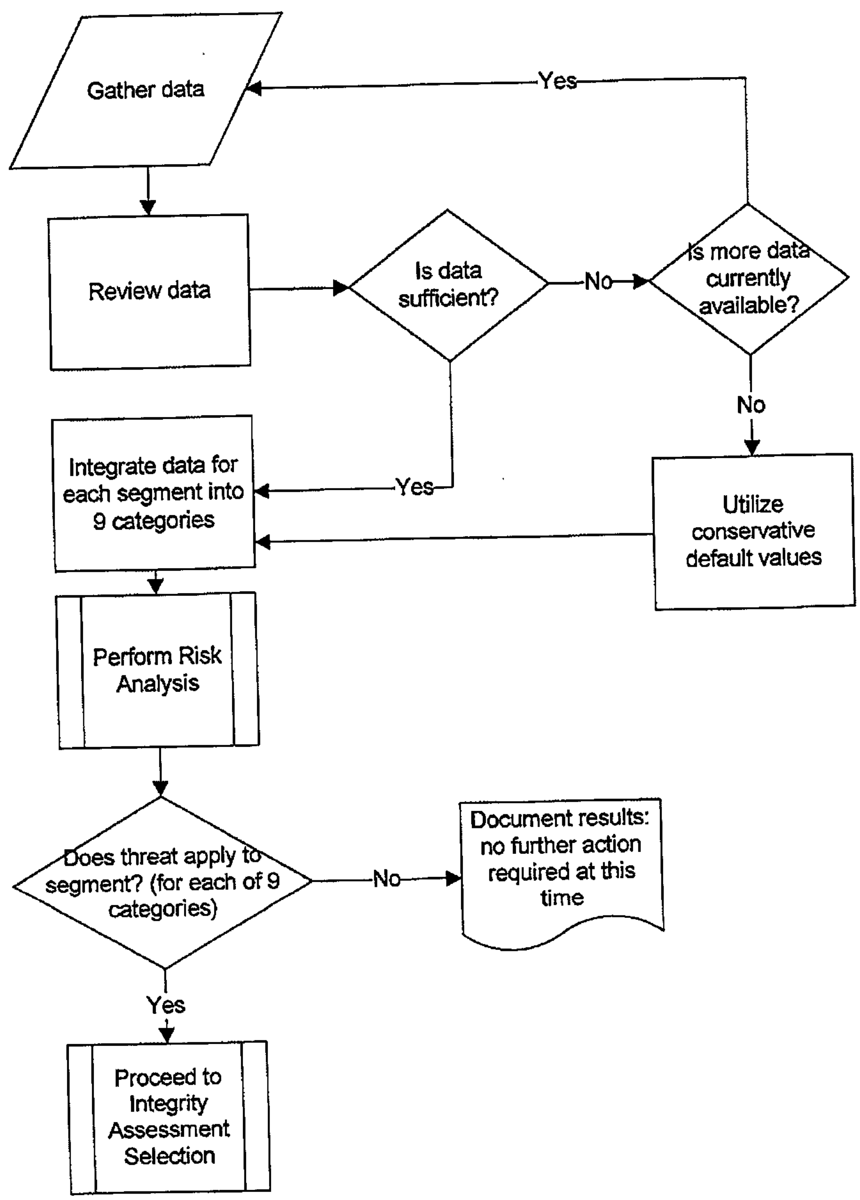
192.917

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

Threat Identification and Risk Analysis Process Flowchart



2.4. Gather Data

B31.8S 4

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.

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:

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

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

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

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

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.

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

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.

Bulletin 111703

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.

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).

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.

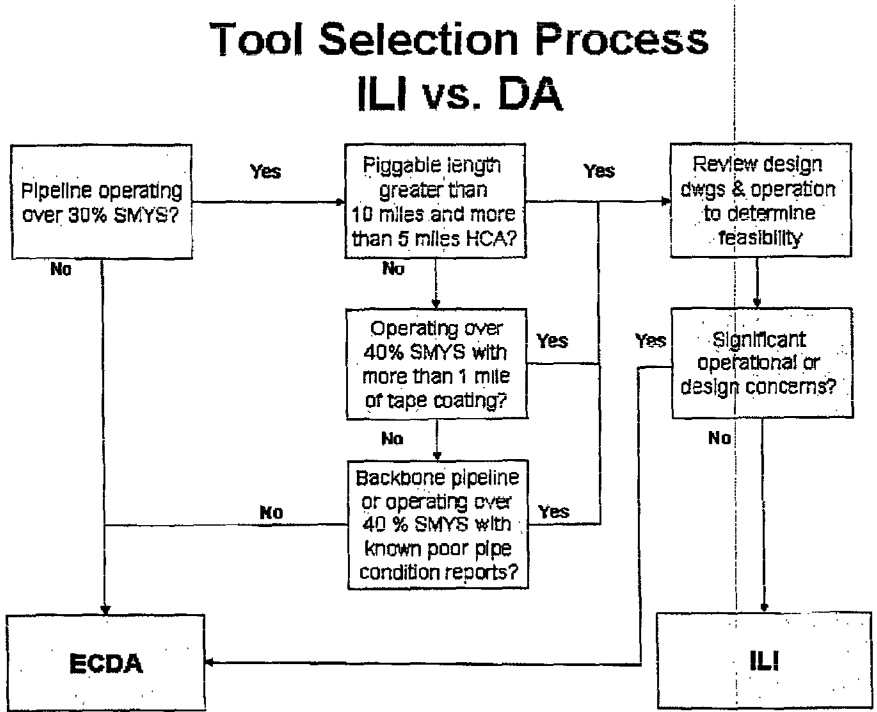
6. Print summary BAP report detailing, for each year, the pipe segments to be assessed, the proposed assessment methods, and the identified threats.

4.5. Selecting the Best Assessment Method(s)

192.919 (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.



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.

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	Manager of Integrity Management	Oversees development of BAP. Can also perform this work.
Senior Risk Management Engineer and Risk management Engineer	Integrity Management Program Manager	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	Approves BAP
VP – Gas Transmission and Distribution	Sr. VP – Engineering and Operations	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	Reviewed annually for additions. On-going updates as assessments results establish re-assessment intervals.
Complete baseline assessment for at least 50% of HCAs identified in original BAP including the highest risk HCA's.	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.

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.

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	PG > 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	7	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 P&M
Note 3: Operator may utilize "other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe"

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.

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	

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.		

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

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	Semi-annual leak survey for all Class 3 & 4 transmission lines not assessed using ILI/DA or PT	Standard S4110	Technical Information Library
Improved/Additional Inspections and Maintenance	Gas Transmission Earthquake Plan and Response Procedure	RMI-04	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	Protect pipelines from encroachments and other unsafe activities near our facilities	SHC 104 – Observed Hazard Notification Third Party	Technical Information Library
Warn landowners of shallow pipe	Natural Gas Pipelines with Elevated 3rd Party	GIB 187	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

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 Section 5 B31.8S

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

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

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"

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 Valvc - 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

192.935(d)
Table E.II.1 Appendix E
Table E.II.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	See Title	As necessary	Technical Information Library
Leak Survey and Repair of Gas Transmission and Distribution Facilities S4110	See Title	As necessary	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

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.	

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).

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/replacments
     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

- **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

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	

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.

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.

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.

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

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).

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

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.

(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.

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.

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

14. Communication Plan

14.1. Scope

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

14.2. Background
192.911
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.

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.

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

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

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

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

17. New HCA Identification

17.1. Scope

This section covers processes for newly identified High Consequence Areas.

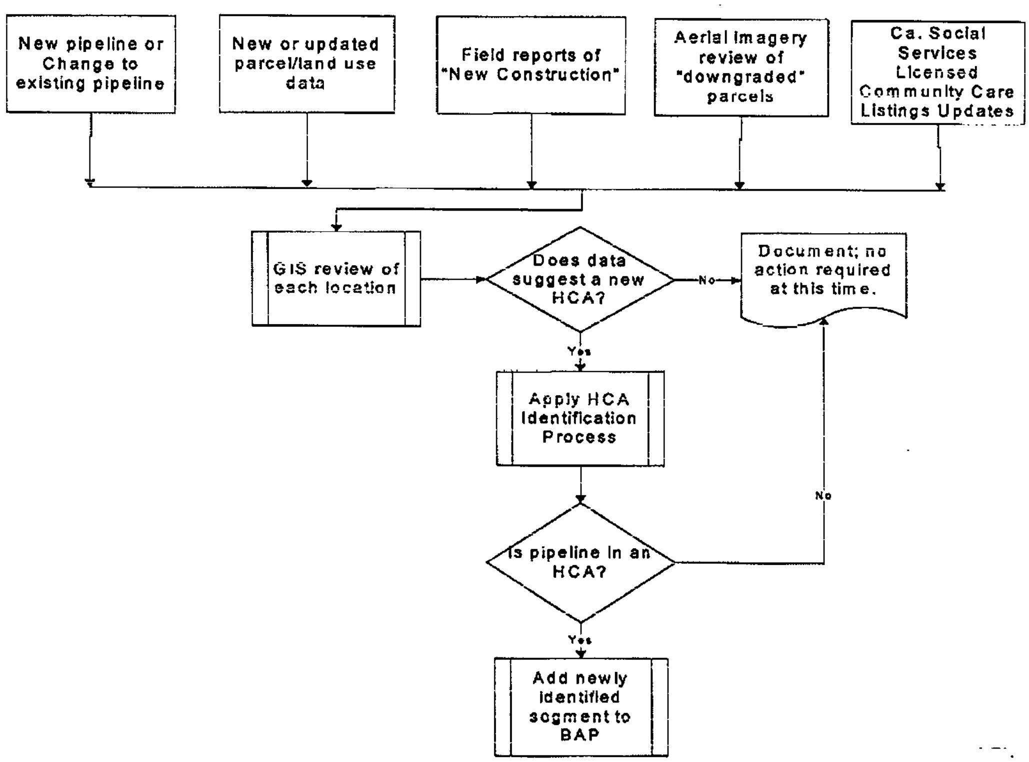
17.2. Background

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

192.905
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).

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.

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 <u>operating</u> 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.

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. 1

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.

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 \\Walnutcrk01\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	1/1/1969	OD	26	Pipe Mat	X60	Trans Der	T
Age	35.85	MOP	890	WT	0.322	SMYS	60000
Seam	DSAW	Jef	1.000	%SMYS	59.89%	Class	1
Girth Weld	A	Girth Jnt	BUTT	Mech Coupling?		PIR	535
Pipe Manuf.							
PT Date	1/1/1969	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	GIS Cond	F	Aform Cond	
ILI		CIS		ECDA		Yr of EC Leak	
AC/DC Int	M	Casing		Soil Res	0	LEC	32.9
Internal Corrosion Specific Considerations							
IIC 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-F)	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	5		
Gas Load	-9	# Cust Out	-9	FSF	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	14.62	IM COF	1.30	IM RISK	18.96
Past Assessment		I01					

Appendix C. Intentionally Left Blank

Appendix D. RMP Change Form

Pacific Gas and Electric

Integrity Management Program Change Form

Changes for RMP- _______
Revision _______ Date____________

Standard Pacific Pipelines Inc.
Attachment D to RMP-06
Page 94 of 99

Section	Change	Reason for Change	Implication of Change

Appendix E. Intentionally Blank

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 panning 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 panning		
	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 panning		

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		

Proprietary Information

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.		

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** __________

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:	Mr. Raffy Stepanian, Chief 505 Van Ness Avenue, Room 2005 San Francisco, CA 94102-3298
	Facsimile	
	Online:	
Reports:	Mail:	Mr. Raffy Stepanian, Chief 505 Van Ness Avenue, Room 2005 San Francisco, CA 94102-3298
	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.

PACIFIC GAS AND ELECTRIC COMPANY

PACIFIC GAS & ELECTRIC COMPANY
GAS TRANSMISSION & DISTRIBUTION ENGINEERING DEPT
CORROSION ENGINEERING SECTION

Procedure for Dry Gas Internal Corrosion Direct Assessment

Procedure No. RMP-10

Integrity Management Program

Prepared By: ______________________ Date: 4-2-10
Dave Aguilar, Senior Advising Corrosion Engineer

Approved By: ______________________ Date: 4-5-10
Sara Burke, Manager of Integrity Management

1.0 PURPOSE

The purpose of this procedure is to describe the process of performing a Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) methodology on specified pipeline segments carrying normally dry gas. The protocol provides instructions, guidance and requirements to perform and document the DG-ICDA process. This procedure is in accordance with Federal Rulemaking on integrity management for gas pipelines (49 CFR Part 192 and ASME/ ANSI B31.8S-2004).

2.0 INTRODUCTION

DG-ICDA is intended to improve safety by assessing internal corrosion in natural gas pipelines and ensuring pipeline integrity.

2.1 Scope

This document covers guidelines for the implementation of the methodology termed Internal Corrosion Direct Assessment for pipelines carrying normally dry natural gas (DG-ICDA) that can be used to help ensure pipeline integrity. The methodology is applicable to pipelines that normally carry dry gas, but may suffer from infrequent, short-term upsets of liquid (water or other electrolytes). DG-ICDA applications may include but are not limited to assessments of internal corrosion of pipeline segments, drips, and crossovers for which alternative methods may not be practical.

DG-ICDA is intended as a tool to predict most likely areas of internal corrosion, including chemical and microbiologically influenced corrosion, and must be used in conjunction with examination techniques. DG-ICDA focuses the direct examination on locations where internal corrosion is most likely.

This procedure is intended to evaluate the integrity of pipeline segments that are primarily threatened by internal corrosion. However, during the assessment process, other types of damage may be identified, such as mechanical damage, external corrosion, stress corrosion cracking (SCC), etc. In those cases, the damage must be documented and appropriate steps shall be taken in accordance with the Integrity Management Plan.

2.2 DG-ICDA Steps

The DG-ICDA methodology is a four-step process requiring integration of pre-assessment and indirect inspection data, with detailed examinations of the internal pipeline surface. The methodology is applicable to natural gas pipelines that normally carry dry gas, but may suffer from infrequent, short-term upsets of liquid (or other electrolyte). The basis of DG-ICDA for normally dry natural gas pipelines is that a direct examination of locations along a pipeline where water would first accumulate provides information about the downstream condition of the pipeline. If the locations along a length of pipe most likely to accumulate water have not corroded, other downstream locations less likely to accumulate water may be considered free from corrosion. The DG-ICDA indirect inspection step relies on the ability to identify locations most likely to accumulate water and is applicable to pipelines where stratified film flow is the primary liquid transport mechanism.

The four steps of the process are:

Pre-Assessment – Includes collecting essential historic and current operating data about the pipeline, determining whether DG-ICDA is feasible, and defining DG-ICDA regions. The types of data to be collected are available in GIS, construction records, operating and maintenance histories, alignment sheets, corrosion survey records, gas and liquid analysis reports, and inspection reports from prior integrity evaluations or maintenance actions.

Identification of ICDA Regions – Covers flow-modeling techniques, developing a pipeline elevation profile, and identifying sites where internal corrosion may be present.

Identification Of Locations For Excavation and Direct Examination – Includes prioritizing and performing excavations and conducting direct examinations of the pipeline to determine whether internal corrosion is present.

Post Assessment – Covers analyzing data collected from the previous three steps to assess the effectiveness of the DG-ICDA process, establishing monitoring processes where IC was found, and determining reassessment intervals.

2.3 **Roles and Responsibilities**

2.3.1 **Manager of Integrity Management :** The Manager of the Integrity Management Department has the overall responsibility to assure that this procedure is implemented effectively. This procedure assigns approval of documents, plans and exceptions to this position. The Manager of the Integrity Management Department may delegate some or all of these approving responsibilities.

2.3.2 **Supervising Engineer:** The Supervising Engineer reports to the Manager of Integrity Management and is responsible for the supervision of the ICDA team and management of all ICDA projects from a programatic perspective. This includes insuring that all ICDA projects and compliance related documentation get completed in a timely manner. This position is also responsible for the creation, revision, and communication of changes associated with ICDA procedures.

2.3.3 **ICDA Project Manager:** The DG-ICDA Project Manager (ICDA-PM) is responsible to assure that all aspects of the assigned DG-ICDA projects are conducted in full compliance with this procedure. In addition, the ICDA-PM is responsible for the effective planning, documenting and communicating the various aspects and stages of the assigned DG-ICDA projects.

2.3.4 **ICDA Project Engineer:** The Project Engineer is responsible for the technical evaluations and analyses conducted through out the assessment process. These include, but are not limited to, sufficient data analysis, DG-ICDA region designation, Indirect Inspection results, remaining strength evaluations, and post assessment analysis. These functions can also be performed by the Senior Technical Advisor (STA).

2.3.5 **Direct Inspection Personnel:** The Indirect Inspection Personnel are responsible for conducting direct examinations. They are responsible for conducting the inspections and tests in accordance with this procedure and other testing procedures that have been referenced in the assessment process.

2.3.6 **Senior Technical Advisor:** The Senior Technical Advisor (STA) reports to the Supervising Engineer of Corrosion Engineering & Technical Support (CETS), and is responsible for the technical aspects of this procedure and that it is implemented effectively. The STA is also responsible for assuring that when this procedure is implemented, all forms and documents associated with this DG-ICDA Procedure are properly completed and filed.

2.4 **Qualifications**

The provisions of this procedure shall be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and related practical experience, are qualified to engage in the practice of corrosion control and risk assessment on ferrous piping systems. The specific qualifications are described below.

2.3.1 **Manager of Integrity Management:** Shall be a degreed engineer and have sufficient gas transmission corrosion related experience to provide guidance and oversight to the personnel conducting the DG-ICDA process.

2.3.2 **Supervising Engineer :** Shall be a degreed engineer or have equivalent pipeline experience. The Supervising Engineer shall have 3-5 years of gas related supervisory experience in maintenance, construction, or engineering/estimating. The Supervising Engineer shall have taken the CGT Corrosion Control training course, and be formally trained on this procedure, RMP-10.

2.3.3 **ICDA Project Manager:** The ICDA-PM shall be a degreed engineer or have equivalent pipeline experience. The ICDA-PM shall have taken CGT Corrosion Control training course and be formally trained on this procedure, RMP-12.

2.3.4 **ICDA Project Engineer:** The ICDA project engineer shall be a degreed engineer with experience with corrosion control in the pipeline industry. The engineer shall have taken the CGT Corrosion Control training and be formally trained on this procedure, RMP-10. In addition, the engineer shall have documented training on the use of RSTRENG.

2.3.5 **Direct Inspection Personnel:** The personnel performing the direct inspections shall meet the CGT Operator Qualification Requirements and also be certified with supporting training documentation for the specific inspections they are conducting for the DG-ICDA.

2.3.6 **Senior Technical Advisor:** Shall be a degreed engineer with at least 5-years corrosion related experience, or shall have equivalent industry certification.

2.3.7 **3rd Party Contractor:** Shall meet the qualifications for the role that they are assuming.

2.5 Definitions

The following are definitions of some key terms used in this procedure:

Considered: A data element that is recommended to be taken into account for the feasibility assessment, designation of DG-ICDA regions, or analysis of test results. Its omission does not require approval or documentation.

Corrosion: The deterioration of a material, usually a metal, that results from a reaction with its environment.

Corrosion Rate: The rate at which corrosion proceeds. The units are typically in mils per year (mpy).

Critical Inclination Angle: Determined by DG-ICDA flow modeling; the lowest angle at which liquid carryover is not expected to occur under stratified flow conditions.

Defined Length: Any length of pipeline until a new input changes flow characteristics or the potential for water entry.

Desired: A data element that is recommended and should be obtained if reasonably possible or easily measured. Its omission does not require approval or documentation.

Direct Examination: Examination of the pipe wall at a specific location to determine whether internal corrosion is present utilizing non-destructive evaluation (NDE) methods. This may be performed using visual, ultrasonic, radiographic, or other means.

Direct Assessment: A structured process for pipeline operators to assess the integrity of pipelines.

DG-ICDA Region: A continuous length of pipeline (including weld joints) or taps off of a pipeline uninterrupted by any significant change in water or flow characteristics that includes similar physical characteristics, sources of gas/liquids, and/or operating history.

Dry Gas: A gas at a temperature above its dew point and without condensed liquids that meets the requirements of Rule 21.

Dry Gas Internal Corrosion Direct Assessment (DG-ICDA): The internal corrosion direct assessment process as defined in this procedure, applicable to normally dry gas systems.

Electrolyte: The liquid adjacent to and in contact with the internal pipeline surface, including the moisture and other chemicals contained therein. In the electrolyte, the ions present will migrate in an electric field.

Fluid: A substance that does not permanently resist distortion. Both liquids and gases are fluids.

Flow Model: A mathematical approach used to model systems. In DG-ICDA, flow modeling is utilized to find the critical inclination angle past which liquid holdup is expected. This includes evaluating flow velocities and the potential of liquid accumulation.

Gathering System: Pipeline and related facilities to collect and move produced gas progressively starting from individual wells to a trunk, common, or main line. Produced gas typically will not meet gas quality specifications typical of gas transmission systems without additional processing.

Geographic Information System (GIS): A system including data, hardware, software, and personnel, for managing information connected with geographic locations.

High Consequence Area (HCA): Location along the pipeline that meets the characteristics specified DOT Part 192, Subpart O.

Historic Inlet: A pipeline inlet that is no longer used to transport gas into the line.

HCA-covered-segment: Any length of pipe within and bounded by the borders of a High Consequence Area (HCA) that meets the characteristics specified by DOT Part 192 Subpart O, requiring it to be included in the company Integrity Management Plan.

Inclination angle: An angle resulting from change in elevation between two points on a pipeline, in degrees.

Indication: Any deviation from the norm as measured by an indirect inspection tool.

Internal Corrosion: Corrosion occurring on the inside of a pipeline.

In-Line Inspection (ILI): The inspection of a pipeline from the interior of the pipeline using an in-line instrumented inspection tool. The tools used to conduct ILI are known as pigs, smart pigs, or intelligent pigs.

Liquid: A substance that tends to maintain a fixed volume but not a fixed shape.

Liquid Holdup: Accumulation of liquid (i.e., input liquid volume is greater than output liquid volume).

Low Point: Pipeline locations and features, such as sags, drips, inclines, valves, manifolds, dead-legs, and traps, where liquids can accumulate.

Microbiologically Influenced Corrosion (MIC): Metal corrosion or deterioration which results from the metabolic activity of microorganisms.

Mil: a thousandth of an inch. Used in corrosion rate in mils per year

Natural Gas: Primarily methane as produced from natural sources.

Nondestructive Evaluation (NDE): An inspection technique that does not damage the item being examined.

Potential Liquid Holdup Location: Pipeline locations and features, such as sags, drips, inclines, valves, manifolds, dead-legs, and traps, where liquids can accumulate. In DG-ICDA, corresponds to any low point and associated uphill inclination until critical inclination angle is reached.

Remediation: A procedure or operation that addresses the factor(s) causing a defect or imperfection.

Required: A data element that must be obtained or its omission must be approved and documented in accordance with Section 8.0 of this procedure.

Segment: A portion of a pipeline that is (to be) assessed using DG-ICDA. A segment may consist of one or more DG-ICDA regions.

Shall: A requirement that must be complied with or its exception must be approved and documented in accordance with Section 8.0 of this procedure.

Should: A recommendation that is desirable to follow.

Stratified Flow: A multiphase-flow regime in which fluids are separated into layers, with lighter fluids flowing above heavier (i.e., higher density) fluids.

Superficial Gas Velocity: The volumetric flow rate of gas (at system temperature and pressure) divided by the cross-sectional area of the pipe.

U.S. Geological Survey (USGS): Responsible for providing scientific information to describe and interpret America's landscape by mapping the terrain, monitoring changes over time, and analyzing how and why these changes have occurred.

3.0 PIPELINE SEGMENTS REQUIRING DG-ICDA

3.2.1 **Identification of DG-ICDA Projects:** Pipeline segments needing or requiring a DG-ICDA can be identified from multiple sources. Usually the requests for DG-ICDA analysis will come from the Integrity Management Program Manager. However, the company may utilize DG-ICDA for other business or operating initiatives. This procedure does not address the identification or ranking processes of pipeline segments requiring DG-ICDA. Where this procedure and RMP-6 come into conflict, the requirements of RMP-6 shall prevail.

3.2.2 **Information Provided With DG-ICDA Request:** The request for a DG-ICDA shall provide the following information:

- Integrity Management (Route) Name (if applicable)
- Route Number
- Source Route (if applicable)
- Starting and ending mile points of requested DG-ICDA
- Approval of the Manager of Integrity Management.

4.0 PRE-ASSESSMENT

4.1 Objectives

The objectives of the *Pre-Assessment* process are to:

- Collect and integrate data
- Assess the feasibility of DG-ICDA
- Document the pre-assessment results

4.2 Data Collection

4.2.1 **Purpose:** Collect and integrate historical data, current data, and physical information for the segments to be evaluated.

4.2.2 **Requirements:** Data elements are identified as either "Required" or "Desired" in Appendix A, Table 1. "Required" data elements shall be collected before the *Pre-Assessment* step is completed. The ICDA-PE may determine that a "Desired" data element is necessary towards assessing a given segment, and thus identify it as "Required".

4.2.3 **Sources:** The data to be collected can be found in construction records, operating and maintenance histories, alignment sheets, GIS, corrosion survey records, and gas and liquid analysis reports, as well as inspection reports from previous integrity evaluations and maintenance actions. The data collected is usually that collected in an overall pipeline risk (threat) assessment and in ECDA programs. Therefore, the ICDA-PE may decide to conduct the *Pre-Assessment* step in conjunction with an ECDA or other risk assessment effort.

4.2.4 **Spatial Mapping:** Spatial mapping of the pipeline is particularly important in DG-ICDA. The ICDA-PE may consider performing a Global Positioning Survey (GPS) to collect data with sub-meter accuracy. If a GPS survey is performed, a static or other high-accuracy and precision method should be used to obtain GIS information. Tool resolution should accurately measure elevation and horizontal/vertical positioning of inclines. Interval spacing should be small enough to accurately measure each inclined length (typically 100' in flat terrain and 50' or less where inclines greater than 1:5 are present).

4.2.4.1 U.S. Geological Survey (USGS) maps with sufficient resolution may also be used, although pipeline elevation changes (such as those at roads, major substructures, and rivers) that would not appear on maps must be considered.

4.2.4.2 When high accuracy data is not available for the entire segment, consider supplementing USGS data with high accuracy and precision GIS field measurements at locations of concern.

4.2.5 **Alignment:** Data and observations from past years and current inspections shall be aligned. These observations may include, but are not limited to, any GIS measurements, locations of roads, major substructures, stream crossings, locations of previous internal corrosion, ECDA data, and any ILI data.

4.2.6 **Documentation:** All data collected shall be recorded in Form A: Data Collection Form in Appendix C. A filing system shall be managed to compile documentation from the DG-ICDA process. Pipeline data including *Pre-Assessment* data, *Region Identification* analysis, *Direct Examination* results, and *Post Assessment* conclusions should be contained in this file.

4.3 Pre-Assessment Review Meeting

4.3.1 **Purpose:** To collect information that is not in written form that is relevant to conducting a DG-ICDA. Also to provide technical insight in conducting the DG-ICDA on the identified segments, communicate the plan of how the DG-ICDA will be conducted, and build consensus for the plan.

Note: This meeting can be part of the ECDA Pre-Assessment meeting per RMP-09.

4.3.2 **Agenda:** The meeting may contain the discussion of the following information:

- Data reports
- GIS Maps
- Leak History/Inspection history
- Gas source history
- Gas flow history
- Drip Locations/liquid volumes
- Feasibility analysis
- DG-ICDA Region Definitions/Locations

4.3.3 **Recommended Attendees:**

- ICDA Project Manager
- ICDA Project Engineer
- Indirect Inspection Personnel

- Transmission System Gas Planner
- Pipeline Engineer
- T&R Supervisor/District Superintendent
- Local maintenance personnel

Meeting Results: Updates and changes to the *Pre-Assessment* data, feasibility analysis, and DG-ICDA regions shall be documented in the project file

4.4 Sufficient Data Analysis

4.4.1 **Purpose:** Identify any missing data and determine if sufficient data is available on pipeline segments in order to perform DG-ICDA.

4.4.2 If data for a particular category are not available, conservative assumptions may be used based on the operator's experience and information about similar systems. The basis for these assumptions shall be documented.

4.4.3 The ICDA-PE should identify any missing data elements that could be collected during a field visit

4.4.4 The ICDA-PE may determine that missing REQUIRED data elements are not essential for completing the DG-ICDA process. In that event, Form L: Exception Report shall be filled out according to Section 8.0 of this procedure.

4.4.5 **Documentation:** The ICDA-PE shall prepare Form A Data Collection Form documenting whether or not there is sufficient data to conduct a DG-ICDA and have the form signed and dated by the ICDA-PM. If there are any missing "Required" data that have not been accounted for by conservative assumptions or the *Exception Process*, then the ICDA-PE shall determine that sufficient data are not available to conduct a DG-ICDA.

4.5 Assessment of DG-ICDA Feasibility

4.5.1 Purpose: Analyze all data collected in the *Pre-Assessment* step and determine if the application of DG-ICDA is appropriate for the given pipeline segments.

4.5.2 Criteria: In order for DG-ICDA to be feasible, a pipeline shall meet the REQUIRED conditions listed under "Feasibility Assessment" in Table 1, Appendix A.

4.5.2.1 The pipe should not normally contain any liquids, including glycols or corrosion inhibitors.

4.5.2.2 The pipe should not have a continuous internal coating providing corrosion protection.

4.5.2.3 The pipe should not have a history of top of the line corrosion.

4.5.2.4 If DG-ICDA is applied to a pipeline with a history of pig cleaning, technical justification shall be provided.

4.5.2.5 The pipe should not contain an accumulation of solids, sludge or scale, unless the influence of these materials has been carefully evaluated taking into consideration the mechanisms listed in Table 2, Appendix A.

4.5.3 Report: The ICDA Project Engineer shall prepare Form B: Feasibility Assessment Report, in Appendix C and have it signed by the ICDA-PM. The report shall contain the following:

- Any conditions that may make DG-ICDA unfeasible,
- Extra actions that need to be taken to ensure a reliable assessment given these conditions, and

- A conclusion regarding the feasibility of performing DG-ICDA on the given segment.

4.6 Pre-Assessment Report

All data, actions and decisions pertinent to the *Pre-Assessment* step shall be documented in a clear and concise manner. Records shall demonstrate compliance with 49 CFR Part 192 and shall be retained for the useful life of the pipeline.

4.6.1 **Report:** A *Pre-Assessment* report shall be prepared with the information itemized below. All forms shall be signed and dated by the ICDA-PM, ICDA-PE and the Manager of Integrity Management.

- Pipeline Maps
- Form A: Data Collection Form
- Methods and procedures used to integrate and align data collected
- Form B: Feasibility Assessment Report

4.6.2 **Approval and Filing:** The report shall be reviewed and approved by the ICDA-PM, ICDA-PE, and the Manager of Integrity Management. A copy shall be kept in the project file.

5.0 IDENTIFICATION OF ICDA REGIONS

5.1 Objectives

A DG-ICDA region is a portion of a pipeline (or multiple pipelines) with a defined length(s). A defined length is any length of pipe until a new input significantly changes either the flow characteristics or the potential for the existence of water and corrosion. DG-ICDA regions shall be defined for each flow direction if flow in a pipeline is bi-directional. A DG-ICDA region may encompass one or more HCA's.

The objectives of the *ICDA Region Identification* step are to:

- Perform steady state flow modeling
- Produce a pipeline elevation profile
- Produce a pipeline inclination profile
- Identify sites where internal corrosion may be present

Each step in the region selection process will be described in the following paragraphs.

5.2 Flow Modeling Calculations

5.2.1 **Purpose:** The purpose of performing flow modeling is to identify the critical angle past which liquid is not expected to flow. The ICDA-PE must identify the most extreme flow conditions (i.e. highest superficial gas velocity) and utilize these in the calculations. Other critical inclination angles for dominant flow conditions may be calculated to provide supplementary data. Additionally, the flow modeling may establish a clear route preference path for liquids to flow through, leaving other flow paths dry. Where this can be established, multiple routes can be assessed using the ICDA process by performing excavations /inspections only on a single route.

5.2.1 The simplified flow model used in this procedure is based on a correlation obtained from results published in GRI 02-0057, and is one example of many models available. Any flow model used must define the critical inclination angle past which liquid is not expected to flow and must be receptive to changes in diameter, and receipt/delivery points. The ICDA-PE must provide technical justification for selecting an alternative flow model to the one contained in this procedure.

5.2.2 The flow model used in this procedure is bound by the following conditions:

- Maximum superficial gas velocity below 25 ft/s
- Nominal pipe diameter between 4 and 48 inches .
- Operating pressures less than 1100 psi, or the pipe is demonstrated to have stratified flow
- Other combinations of the above parameters if flow modeling has shown that only stratified flow will occur at operating conditions

5.2.3. The following data and values are required to calculate the critical inclination angle:

- Pipe inner diameter, ID (in)
- Low operating pressure, P (psi)*
- Maximum flow rate, SPT Flow Rate (MMSCF/D)*
- Average temperature, T (°F)
- Liquid density, ρ_L (default 62.43 lb/ft^3)
- Molecular weight of gas, MW (if methane assumed to be 16 lb/lb-mol)
- Compressibility factor, Z = .83 (Z can also be obtained from published charts of Natural Gas Compressibility Curves)
- Gravity, g=31.27ft/s^2
- Universal gas constant, R = 10.73 (psia*ft^3/lb-mol*R)

5.2.4 The critical angle can be determined from the following calculations:

5.2.4.1 Convert the temperature into Rankine

$T\,(R) = T\,(^{\circ}F) + 459.67$

5.2.4.2 Calculate the gas density, ρ_G

$\rho_G = ((P+14.7)*MW)/(R*T*Z)$

5.2.4.3 Calculate the operating pressure (OP) flow rate, or the rate for specific conditions if flow rate data are in standard (STP) units

OP Flow Rate = (STP Flow Rate)*T*Z*P_{STP}/((P+14.7)*T_{STP})

Where P_{STP} = 14.7 psi, and T_{STP} = 520 R (60°F)

5.2.4.4 Convert the OP Flow Rate into (ft^3/s):

OP Flow Rate(ft^3/s)=OP Flow Rate(MMCF/D)*10^6*1D/24hr*1hr/3600s

5.2.4.5 Calculate the superficial gas velocity, V_g

V_g = OP Flow Rate/ [π*((ID*1ft/12in)^2)/4]

5.2.4.6 Calculate the critical angle, θ

* Or the combination of actual operating conditions of these two variables that produces the highest superficial gas velocity.

$$\theta = \arcsin\left(.675 \frac{\rho_g}{\rho_l - \rho_g} * \frac{V_g^{\,2}}{g*(ID*\frac{1ft}{12in})} \right)^{1.091}$$

5.2.5 The critical inclination angle is not necessarily constant within a DG-ICDA region (e.g., changes in internal diameter) and is usually plotted against distance.

5.2.6 The results of the critical angle calculation shall be documented. Form D: Flow Modeling, in Appendix C, should be used for this purpose.

5.3 Elevation Profile Calculations

5.3.1 The ICDA-PE may calculate the elevation profile using the collected pipeline data. In this DG-ICDA process an inaccurate elevation profile will lead to an incorrect inclination profile. Using known locations of liquid hold up assumed to have a probability for internal corrosion (see IC "Triggers List" Appendix E) may also be used to select direct examination sites.

5.3.2 If an elevation profile is used then the elevation should be plotted against distance for each region, as shown in the example in Figure 1 in Appendix B.

5.4 Inclination Profile Calculations

5.4.1 The ICDA-PE shall calculate the inclination profile using collected pipeline data. The inclination angle at every location can be calculated as follows:

$$\theta = \arcsin\left(\frac{\Delta elevation}{\Delta length}\right)$$

5.4.2 The inclination angle should be plotted against distance for each region as shown in the example in Figure 1 of Appendix B.

5.4.3 The ICDA-PE may identify and estimate all uncertainties associated with determining the inclination angles and place a record of these uncertainties in the DG-ICDA project file. The records should be used for screening GIS measurements with respect to DG-ICDA and in consideration with other results during the *Post Assessment* step.

5.5 ICDA Region Selection

5.5.1 The ICDA-PE shall integrate the flow modeling results with the pipeline inclination profile, or known hold up locations in order to determine sites where internal corrosion may be present. Selection should include consideration of inclination angles at road crossings, rivers, drainage ditches and other locations.

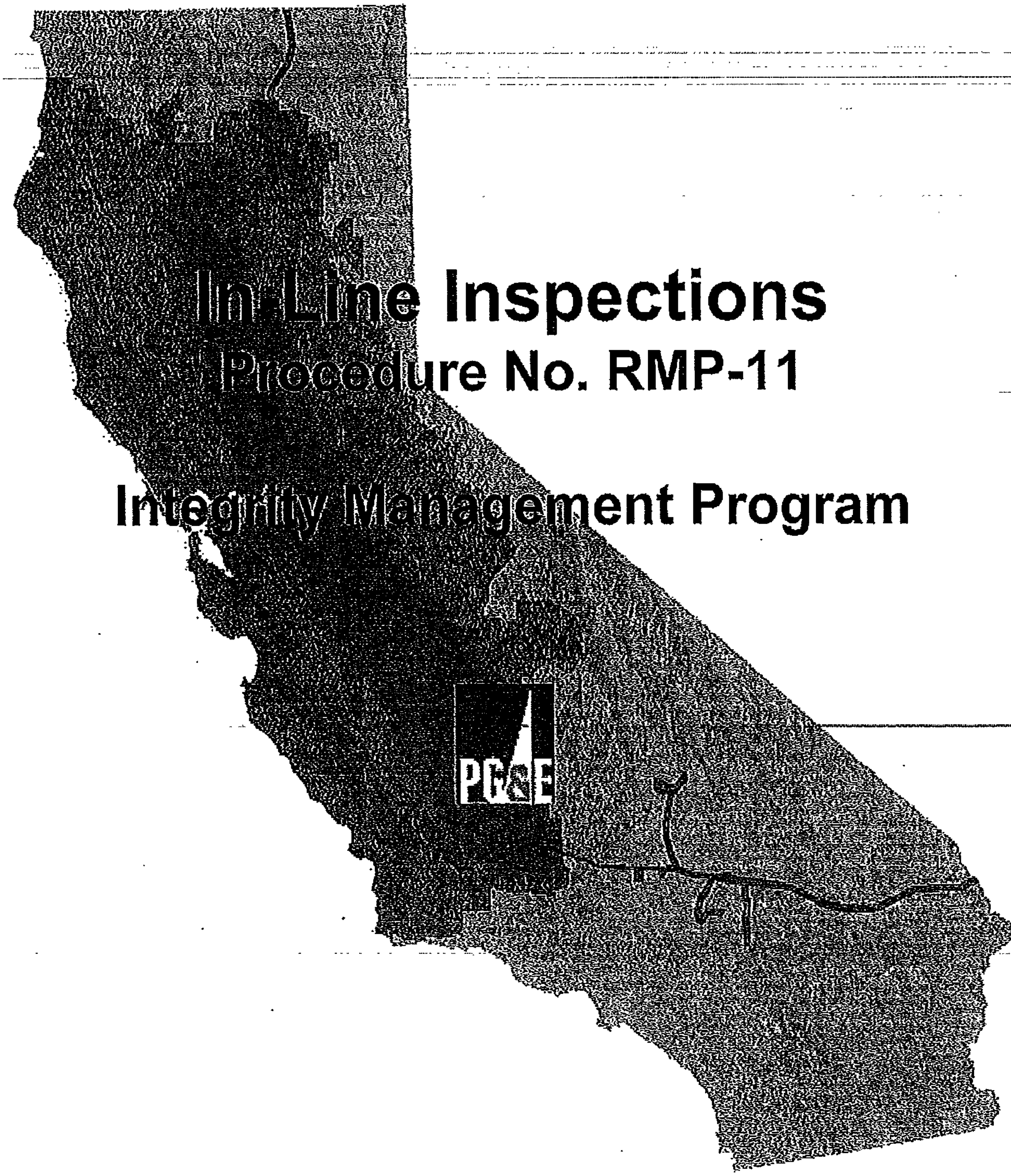
5.5.1.1 Sites where liquid holdup may possibly occur should be identified based on a comparison of the calculated critical inclination angle with the inclination profile for a given segment.

5.5.1.2 Locations where liquid is known or was known to be present shall also be considered for region selection.

5.5.2 The ICDA-PE shall identify DG-ICDA regions based on establishing probable locations of liquid hold-up. Region 1 shall be the standard region for general liquid hold-up. Other regions may be established based on other parameters or conditions in the operating system, that in the judgment of the ICDA-PE and ICDA Team , establish the need for additional regions.

5.5.2.1 The "Required" elements listed under "Need" in Form A: Data Collection Form, must be collected and analyzed to determine if additional regions are needed. If that information is not available, then its omission must be approved and documented on Form B "Feasibility Assessment Report" before proceeding.

PACIFIC GAS AND ELECTRIC COMPANY



In-Line Inspections

Procedure No. RMP-11

Integrity Management Program

Rev. 2, June 10, 2008

Proprietary Information

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References

1. ANST NO. ILI-PQ-2003 "IN-LINE INSPECTION PERSONNEL QUALIFICATIONS & CERTIFICATION"
2. API 1163 1ST EDITION "IN-LINE INSPECTION SYSTEMS QUALIFICATION STANDARD"
3. NACE RP 0102-2002 "STANDARD RECOMMENDED PRACTICE, IN-LINE INSPECTION OF PIPELINES"
4. ASME B31.8S-2004 "MANAGING SYSTEM INTEGRITY OF GAS PIPELINES"
5. 49 CFR PART 192, SUBPART O "PIPELINE INTEGRITY MANAGEMENT"
6. CGT CLEARANCE PROCEDURE S4420
7. RMP-06 "INTEGRITY MANAGEMENT PROCEDURE"
8. UTILITY WORK PROCEDURE WP4100-05 "SELECTION OF GAS PIPELINE REPAIR METHODS"
9. DCS/GTS STANDARD S4413 "CPUC AND DOT REPORTABLE INCIDENTS, CURTAILMENTS AND CONDITIONS AND LOW PRESSURE SYSTEM PROBLEM REPORTING"
10. UTILITY WORK PROCEDURE WP4430-07 "ESTABLISHING SET POINTS ON OVERPRESSURE PROTECTION DEVICES"
11. UO GUIDELINE G14413 "PROCEDURE FOR EXCAVATING PIPELINES AND SERVICES"

RMP-11

1.0 PURPOSE

The purpose of this procedure is to describe the process of performing an In Line Inspection (ILI) on specified buried gas transmission pipeline segments. This procedure is in accordance with 49CFR Part 192, Subpart O – Pipeline Integrity Plan and ASME B31.8S-2001, *Supplement to B31.8 on Managing System Integrity of Gas Pipelines*. It provides instructions, guidance, and requirements to ensure consistent inspections, responses to anomalies and documentation of the ILI results.

1.1 **Revision:** All changes in the Procedure shall follow RMP-06 Section 12 and be reviewed with all involved personnel whenever a revision is published. In case of conflict between RMP-06 and RMP-11, RMP-06 governs.

2.0 INTRODUCTION

In-Line Inspection requires a structured process that is intended to improve safety by assessing and mitigating the pipeline integrity threats, such as, corrosion, mechanical damage, S.C.C, etc. By identifying and sizing anomalies in the pipeline, the ILI process seeks to proactively prevent anomalies from growing to sizes that are large enough to affect the structural integrity of the pipeline segments inspected.

2.1 ILI Methodology

The ILI methodology is a four-step process that requires the integration of data from the In-Line Inspection, direct pipe surface examinations, and the pipe's physical characteristics. The four steps of the process are:

Pre-Assessment: The Pre-Assessment step collects historic and current data to determine whether the ILI is feasible and what tool is appropriate and to assist in the interpretation and analysis of the inspection results. The types of data to be collected are typically available in GIS, transmission and distribution plat sheets, as-built job files, district and division records. This step also defines the work necessary to verify the pipeline segments are "piggable" or to make the segment "piggable."

In-Line Inspection: The In-Line Inspection step covers the route preparation and pipeline cleaning. This step also includes performing In-Line Inspection runs and the data analysis by the vendor to identify and quantify the pipe wall anomalies.

Direct Examination: The Direct Examination step includes reviewing of In-Line Inspection data to prioritize the anomalies for excavations and evaluations. Data from the direct examinations are utilized to verify the accuracy of the ILI results and evaluate the identified anomalies in regards to pipeline integrity. It also includes requirements of repairs, performing the root cause analysis, and the requirements of the RMP-11 Final Report.

Post-Assessment: The Post-Assessment step covers analyses of data collected from the previous three steps and the development of a Post Assessment Plan to mitigate any significant deficiencies identified by the Root Cause Analysis and the ILI final report. The plan includes assigning re-inspection intervals and assessing/monitoring the overall effectiveness of the ILI process.

2.2 Roles and Responsibilities

Manager of Technical Services: The Manager of Technical Services has the overall responsibility to ensure that this procedure is implemented effectively. This procedure is used to assign approval of documents, plans and exceptions to this procedure. The Manager of Technical Services may delegate some or all of these approving responsibilities.

ILI Program Manager: The ILI Program Manager is responsible for ensuring that all aspects of the ILI program are conducted in full compliance with this procedure. The Program Manager is responsible for overall compliance, budgeting, and resource planning necessary to implement the ILI program.

ILI Engineer (ILE): The ILI Engineer is responsible for the implementation of all engineering aspects of this procedure included in the pre-assessment, in-line inspection, direct examination and post assessment phases.

Senior Risk Management Engineer (SRME): The Senior Risk Management Engineer is responsible for the quality control of the ILI projects. This person will be the consultant to the ILI Team and Integrity Management Team for all ILI projects. This person is responsible for reviewing the critical interim phases and the RMP-11 Final Report for the compliance of this procedure and leads the team creating the Long Term Integrity Management Plan (LTIMP).

ILI Project Manager (PM): A Project Manager will be assigned to manage each ILI project. This person is responsible for ensuring that all aspects of the assigned ILI project are performed in full compliance with this procedure. In addition, the Project Manager is responsible for effectively planning, documenting and communicating the various aspects and stages of the assigned ILI project. The project is the responsibility of the Project Manager until the final report is completed and formally transmitted to the Integrity Management Program Manager.

Integrity Management Program Manager (IMPM): This person is responsible for ensuring the post-assessment is completed for each ILI and the pipeline re-assessment interval is documented and scheduled. This person is also a resource to the ILI Program Manager for risk assessments

Corrosion Engineer (CE): The Corrosion Engineer is responsible for the technical evaluation of direct examinations and preparing root cause analysis in accordance with this procedure.

Direct Examination Personnel: The In-Line Inspection Personnel are responsible for performing direct examinations in accordance with this procedure and other testing procedures that have been referenced in the assessment process.

2.3 Qualification and Training Requirements

The provisions of this procedure **shall** be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and related practical experience, are qualified to engage in the practice of pipeline engineering on transmission piping systems. The specific qualifications are described below.

Manager of Technical Services: Qualifications and Training requirements covered in RMP-06

ILI Program Manager: The Program Manager **shall** be a degreed engineer with a minimum of 5 years of experience (or equivalent) performing In-Line Inspections in the pipeline industry. Additionally, the ILI Program Manager shall have a minimum of 5 years experience in either Pipeline Design, Operations or Integrity Management with a strong working knowledge of CFR 49 Part 192.

Training: 1. Review of RMP-11 annually, 2. RSTRENG Training Course, 3. GT&D Corrosion Control Training Course, 4. Defect Assessment Course and 5. Industry Pigging Course

ILI Engineer (ILE): The ILE **shall** be a degreed engineer and have a minimum of 1 year experience in Gas Distribution or Gas Transmission Engineering, Planning or Operations. The ILI Engineer shall work under the guidance and supervision of the ILI Program Manager.

Training: 1. Review of RMP-11 annually, 2. RSTRENG Training Course, 3. GT&D Corrosion Control Training Course, 4. Defect Assessment Course and 5. Industry Pigging Course

Sr. Risk Management Engineer (SRME): Qualifications and Training requirements covered in RMP-06

ILI Project Manager (PM): The PM **shall** have project management experience within the gas industry.

Training: 1. Review of RMP-11 annually, 2. Project Manager Training per PG&E Project Manager Guidelines.

Integrity Management Program Manager (IMPM): Qualifications and Training requirements covered in RMP-06

Corrosion Engineer (CE): Qualifications and Training requirements covered in RMP-06

Direct Examination Personnel: The personnel performing the direct examinations shall meet their employer's Operator Qualification requirements as well as being certified with supporting training documentation for the specific inspections they are conducting.

2.4 Record Retention: All forms and reports created for the ILI run shall be on file for the life of the facility.

2.5 Definitions: The following are definitions of some key terms used in this procedure

Shall: Is a requirement that must be complied with or its exception approved and documented in accordance with Section 7.0 of this procedure.

Should: Is a recommendation that is desirable to follow if possible. Not following the recommendation does not have to be documented or approved.

Required: "Required" data listed in Table 3.3.1 must be obtained for an effective ILI project or its omission be approved and documented in accordance with Section 3.7 of this procedure.

Desired: "Desired" data listed in Table 3.3.1 should be obtained if it is documented or easily measured. Its omission is not required to be approved or documented.

Considered: "Considered" is a recommendation that a data element is taken into account for the selection of In-Line Inspection tools, interpretation, or analysis of test results.

Failure Pressure (Pf): Calculated burst pressure from of an ILI anomaly using RSTRENG or equivalent method.

Failure Pressure* (Pf*): Calculated burst pressure of an ILI anomaly including tool tolerances.

Discovery Pressure (Pdis): Pdis is defined as the pipeline pressure at the time the condition was discovered and for the purpose of this procedure we will use the highest pipeline operating pressure during the In-line inspection tool ILI run or the maximum operating pressure between the ILI run and the time of discovery.

Safe Pressure (Ps): Pf X (times) class location design factor

GIS: Geographic Information System. The computerized graphics and database used to store the location, specifications, and integrity assessment of all pipeline facilities.

GPS: Global Positioning System. Process by which coordinates are captured for mapping purposes.

AGM: Above Ground Marker. Used for tracking ILI tool while traveling through pipe

CPA: Cathodic Protection Area

MAOP: Maximum allowable operating pressure for a section of pipeline between pressure controlling points. This is often determined by the "weakest" link of segments, fitting or valve between the pressure controlling points.

Discovery: When PG&E receives actionable information on anomalies which have been reviewed by an ILI analyst.

Pipeline Features List: A list detailing the various features of a pipeline, such as, pipe specifications, valves, tees, bends, etc. per PG&E records such as: Pipeline Survey Sheets, Plats, As-built drawings, Project files, etc.

3.0 PRE-ASSESSMENT

3.1 Objectives

The objectives of the pre-assessment process are to:

- Determine the feasibility of conducting an ILI
- Determine if sufficient data exists to conduct an ILI
- Collect the required pipeline data to assist in the interpretation and analysis of inspection results
- Document pre-assessment results

3.2 Pipeline Segments Requiring ILI

3.2.1 **Identification of ILI Projects:** Pipeline segments needing or requiring an ILI can be identified from multiple sources (IMAC, BAP, IMA). Usually the requests for an ILI will come from the Integrity Management or Risk Management Programs. However, the company may utilize ILI for other business or operating initiatives. This procedure does not address the identification or ranking processes of pipeline segments requiring ILI. Please refer to RMP-06 for details.

3.2.2 **Information Provided With ILI Request:** The request for an ILI **shall** have the following information supplied to the ILI Program Manager:

- Route number

- Starting and ending mile points of requested ILI
- Risk Ranking
- Location of HCA, if present, within the ILI project mile points (starting and ending)

3.3 **Data Collection (Pre-Field Visit)**

3.3.1 **Data Collection Objectives:** A key aspect of the Pre-assessment step is the collection of pipeline data. Table 3.3.1 PRE-ASSESSMENT DATA provides a checklist of the data elements needed to conduct the ILI.

3.3.2 **Data Collection Phases:** Data collection and analysis is a continuous activity throughout the ILI process. In the Pre-assessment step this procedure divides the data collection into two steps; "Pre-Field Data Collection" and "Field Data Collection."

3.3.3 **Data Requirements:** The "Need" for the data elements is identified in Table 3.3.1 as either "REQUIRED" or "DESIRED." Data elements that are identified as REQUIRED **shall** be obtained before completion of the Pre-assessment step or approved to be delayed or omitted from data collection in accordance with Section 3.7 of this procedure. "DESIRED" data elements should be obtained if the data is available in existing records or can be obtained from easily conducted measurements or examinations. The Program Manager may consider desired data sufficiently important to classify it as "REQUIRED" for a specific ILI analysis.

3.3.4 **Data Sources:** Table 3.3.1 provides guidance to the possible sources for each data element. If the data element is not available in the listed sources the ILI Engineer should use good judgment on seeking the data elsewhere. A pipeline features list **shall** be compiled to identify all information about the pipeline such as: pipe wall thickness, grade, seam, fittings, valves, etc. for this purpose.

3.3.5 **Data Documentation:** The collection of information **shall** be indicated on the "DATA ELEMENT CHECK SHEET" (Form A). Items should be signed off by the person who checked/filled the specific data element row.

Proprietary Information

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST

Description				Requirements			Data Source					
ID #	Data Element Description	In-Line Inspection Tool Selection	Interpretation and Analysis Of Inspection Results	Need[1]	Inspection Tool[2]	Interpretation and Analysis of Inspection Results[2]	GIS	As-built Job file	Field	Districts or Division	Other	Comments
1.0 Pipe Related												
1.1	Diameter	May reduce detection capability or prohibit passage of tool	For performing RSTRENG	R	R	R	X	X				
1.2	Wall thickness	May reduce detection capability or prohibit passage of tool	Impacts critical anomaly size	R	R	R	X	X				
1.3	Grade		For performing RSTRENG	R	N/R	R	X	X				
1.4	Seam Type		Older pipe typically has lower weld seam toughness that reduces critical anomaly size. Pre-1970 ERW or flash welded pipe may be subject to higher corrosion rates than the base metal	D	N/R	C	X	X				
1.5	Year Manufactured	May influence tool selection.	Older pipe typically has lower weld seam toughness that reduces critical anomaly size. Pre-1970 ERW or flash welded pipe may be subject to higher corrosion rates than the base metal	D	N/R	C	X	X				Assume the same year as installed unless found otherwise.
2.0 Construction Related												
2.1	Year installed		Impacts time over which coating degradation may occur, anomaly population estimates, and corrosion rate estimates	D	N/R	C	X	X				
2.2	Recent route changes/ modifications that may not be in GIS			D	C	N/R		X	X	X		
2.3	Construction practices		May indicate construction problems that may have occurred; e.g., BBCR, miter bends, wrinkle bends, etc.	D	C	C		X			Engr. Stds. drawings	
2.4	Location of major pipe appurtenances such as valves and taps	Investigate potential need for replacement or the installation of bars for tees.	Provides a 'known' reference for geo-referencing indications	R	R	C	X	X	X			

[1] R = Required, D = Desired (See paragraph 2.5 for definitions)
[2] R = Required, C = Considered; N/R = Not required

Description				Requirements			Data Source					
ID #	Data Element Description	In-Line Inspection Tool Selection	Interpretation and Analysis Of Inspection Results	Need[1]	Inspection Tool[2]	Interpretation and Analysis of Inspection Results[2]	GIS	As-built Job file	Field	Districts or Division	Other	Comments
2.5	Location of bends, including miter bends and wrinkle bends	May indicate locations at which replacements are needed to make the pipeline piggable	Provides a 'known' reference for geo-referencing indications	R	R	C		X			Trans. Plat Sheet	
2.6	Location of casings		Provides a 'known' reference for geo-referencing indications (Access issue for post pigging dig and potential coating defect)	D	N/R	C		X	X	X		
2.7	Proximity to other pipeline structures, HV electric transmission lines and rail crossings		Possible CP interference and 3rd party damage	D	C	C	X		X			
2.8	Underwater sections and river crossings		Access issue for post pigging dig and potential coating defect	C	N/R	C	X	X	X			
2.9	Location of bores		Access issue for post pigging dig and potential coating defect	D	N/R	C		X				
3.0 Soils/Environmental												
3.1	Soil characteristics & types		Can be useful in interpreting results. Influences corrosion rate	D	C	C	X		X		Form 4110	GIS soil data
3.2	Assessment of environmental conditions		May indicate potential environmentally sensitive areas	D	N/R	C	X		X			
3.3	Topography		Conditions such as rocky areas can make field inspections difficult or impossible.	D	C	N/R			X			
3.4	Land use (current/pass)		Can be considered in evaluating the potential severity of damage.	D	C	C	X		X			Asphalt vs. concrete
3.5	Locations of poor drainage		. Influences corrosion rate and remaining life calculation	D	N/R	C			X	X		
4.0 External Corrosion												
4.1	CP System Type (anodes, rectifiers, and locations)		Support root cause analysis and CIS survey	D	N/R	C			X		CPA Records	
4.2	CP system boundaries		Support root cause analysis and CIS survey	D	N/R	C			X	X	CPA Records	
4.3	Locations of Isolation Points		Support root cause analysis and CIS survey	D	N/R	C			X	X	CPA Records	

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Description				Requirements			Data Source[3]					
ID #	Data Element Description	In-Line Inspection Tool Selection	Interpretation and Analysis Of Inspection Results	Need[1]	Inspection Tool[2]	Interpretation and Analysis of Inspection Results[2]	GIS	As-built/Job file	Field	Districts or Division	Other	Comments
4.4	Locations of Connections to Distribution		Support root cause analysis and CIS survey	D	N/R	C			X	X	CPA Records	
4.5	Stray Current source/locations		Support root cause analysis and CIS survey	D	N/R	C			X	X	CPA Records, past survey reports.	
4.6	Test point locations (pipe access points)		May Provide geographic reference for ILI run	D	N/R	C	X		X	X	CPA Records	
4.7	CP evaluation criteria		Used in post-assessment analysis	D	N/R	C					CPA Records, Paradigm	
4.8	CP maintenance history		Support root cause analysis and CIS survey	D	N/R	C				X	CPA Records, Paradigm	
4.9	Years without CP applied		Negatively affects ability to estimate corrosion rates	D	N/R	C		X		X		
4.10	Coating type – pipe		Coating type may influence time at which corrosion begins and estimates of corrosion rate based on measured wall loss.	D	N/R	C	X	X				
4.11	Coating Condition		May help with root cause analysis of anomalies	D	N/R	C	X			X	Direct Assessment	
4.12	Current demand		Support root cause analysis and CIS survey	D	N/R	C				X	CPA Records	
4.13	CP survey data/history		Support root cause analysis and CIS survey	D	N/R	C					CPA Records Paradigm, Corrosion Group	
5.0 Operational Data												
5.1	Operating stress level Pressure, Flow Rate	For controlling the pigging velocity	Impacts critical anomaly size	R	R	R	X				GSO, TSP	
5.2	Monitoring programs (Patrol leak surveys etc.)		May impact repair, remediation and replacement schedules.	D	N/R	C					Corrosion Group, Form 4110	
5.3	Pipe inspection reports-excavation		Provide useful data for post assessment analysis or data verification	D	N/R	C	X			X	Form 4110	

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Description				Requirements			Data Source					
ID #	Data Element Description	In-Line Inspection Tool Selection	Interpretation and Analysis Of Inspection Results	Need[1]	Inspection Tool[2]	Interpretation and Analysis of Inspection Results[2]	GIS	As-built Job file	Field	Districts or Division	Other	Comments
5.4	Repair history/records, steel/composite repair sleeves, repair locations		Provide useful data for post assessment analysis or data verification	D	N/R	C	X			X	Form 4110	
5.5	Leak rupture history		Provide useful data for post assessment analysis	D	N/R	C	X			X	Form 4110	
5.6	Type and frequency of third party damage (Review construction activities with operating personnel.)		High third party damage areas may have increased coating fault anomalies.	R	N/R	R	X		X	X	Form 4110 USA Data Base Patrol Records	
5.7	Other prior integrity related activities – CIS, ILI runs, etc.		Useful post assessment data	R	N/R	R	X				Corrosion Group, System Integrity	If applicable
5.8	Hydro Test dates/pressures		Affects manufacture threat review	D	N/R	C	X	X				
5.9	Known areas of shallow cover.		Potential 3rd party damage	D	N/R	C			X	X		
5.10	Location of abnormal pipe operating temperatures		Possible locations for SCC, Influence of activating manufacture defects.	D	N/R	C					SCADA	
6.0 Internal Corrosion (IC)												
6.1	History of IC leaks		Influence post pigging dig plan	D	C	C	X		X	X		Pipe inspection form
6.2	Received gas from gathering or storage lines		To establish threat for potential IC, Influence post pigging dig plan	D	N/R	D	X		X			
6.3	Drip location		Influence post pigging dig plan	D	N/R	C	X		X			Check drip logs, PLM
6.4	Drip fluid analysis		Influence post pigging dig plan	D	D	D	X		X	X		
6.5	Inhibitor injection		Influence post pigging dig plan	D	D	D	X		X	X		Check drip logs, PLM
6.6	Previously "pigged"		Influence post pigging dig plan	D	N/R	C				X		Previous cleaning pigs

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Description				Requirements			Data Source					
ID #	Data Element Description	In-Line Inspection Tool Selection	Interpretation and Analysis Of Inspection Results	Need[1]	Inspection Tool[2]	Interpretation and Analysis of Inspection Results[2]	GIS	As-built Job file	Field	Districts or Division	Other	Comments
6.7	Corrosion monitoring (LPR probes, weight loss coupons, corrosometer probes, etc.)		Influence Root Cause analysis, post pigging dig plan, and the LTIMP prevention and mitigation plan.	D	N/R	C				X	Maintenance Records	
7.0 Hard Spot												
7.1	Year installed, Mill, Seam type, etc per RMP-06 Section 3.5	Will affect tool selection	Influence Root Cause analysis, post pigging dig plan, and the LTIMP prevention and mitigation plan	D	C	C	X	X				
7.2	Records of hard spots failures	Will affect tool selection	Influence Root Cause analysis, post pigging dig plan, and the LTIMP prevention and mitigation plan	D	C	C	X				Form 4110	
7.3	Abnormal CP levels		Influence Root Cause analysis, post pigging dig plan, and the LTIMP prevention and mitigation plan	D	C	C	X			X		

3.4 Data Analysis (Pre-field visit)

3.4.1 **Identification of Missing Data:** Once the Pre-field Visit data is collected the ILI Engineer should analyze the data to identify missing elements, and develop a list of data that will need to be obtained in the field. Form A - DATA ELEMENT CHECK SHEET in APPENDIX A can be used for this purpose.

3.5 Field Visit

3.5.1 **General Description:** Examining the physical locations where the ILI is to be conducted is a key activity in the gathering of data. It is important to collect as much data as possible to achieve the objectives of the Pre-assessment and effectively plan for the In-Line Inspection step of the ILI process. Hence, preparation is key to conducting an effective field visit. Some of the data elements from Table 3.3.1 that may require field collection or verification in the field are:

TABLE 3.5.1: TYPICAL FIELD COLLECTED DATA

ID	Description	ID	Description
2.2	Recent route changes/modifications that may not be in GIS	3.2	Assessment of environmental conditions
2.4	Presence of major pipe appurtenances such as valves and taps	4.1	CP system type (anodes, rectifiers, and locations)
2.6	Presence of casings	4.2	Stray Current source/locations
2.7	Proximity to other pipeline structures, HV electric transmission lines and rail crossings	4.3	Test point locations (pipe access points)
3.1	Soil characteristics & types	5.6	Type and frequency of third party damage (Review construction activities with operating personnel)

3.5.2 **Documentation:** All data collected in the field that will be used in the ILI project shall also be included on Form A.

3.6 **Data Filing:** Data collected during pre-assessment phase shall be stored in the final report per Section 5.9.

3.7 **Data Analysis** Once the Field Visit data is collected the ILI Engineer shall analyze the data to identify missing REQUIRED data elements, and conduct a SUFFICIENT DATA ANALYSIS – FORM B.

3.7.1 **Sufficient Data Analysis:** The data shall be analyzed to determine if there is sufficient data to conduct an ILI. The analysis should include the following:

- **Missing Required Data:** If there is missing required data and it is felt that this data is not essential to the ILI then the reason it is not necessary shall be explained in Form B - SUFFICIENT DATA ANALYSIS FORM.
- **Missing Desired Data:** The ILI Engineer should review the missing desired data to identify if any of those data elements are essential to

conduct the ILI. If some of the missing desired data is essential it should be identified in the analysis and document on Form B.

3.7.2 **Documentation:** The ILI Engineer **shall** document if there is sufficient data to conduct an ILI. Form B - SUFFICIENT DATA ANALYSIS FORM can be used for this purpose.

3.8 **Feasibility Analysis**

3.8.1 **Analysis:** The ILI Team **shall** integrate and analyze the data collected on the pipeline segments and determine whether the use of ILI is appropriate. The framework for this analysis is that the Program Manager **shall** examine the existing data in each of the five categories in Table 3.3.1 (Form A) and assess the following:

- **In-Line Inspection:** In-Line Inspection should address physical, operational and economic considerations.
- **Direct Examination:** Direct Examination should address physical, operational and economic considerations.

3.8.2 **Documentation:** The ILI Engineer **shall** prepare Form C - FEASIBILITY ANALYSIS FORM and have it approved by the ILI Program Manager.

3.9 **ILI Pre-Assessment Review Meeting(s)**

3.9.1 **Purpose:** The ILI Project Manager **shall** conduct a meeting(s) to review the pre-assessment results, communicate the plan of how the ILI will be conducted, and build consensus for the plan.

3.9.2 **Agenda:** The meeting(s) should have the following in its agenda:

- Review the ILI Request Information, DATA ELEMENT CHECK SHEET (Form A), SUFFICIENT DATA ANALYSIS FORM (Form B), and FEASIBILITY ANALYSIS FORM (Form C)
- GIS Maps
- Discussion of required pipeline modifications

~~3.9.3 **Attendees:** The meeting(s) may have the following attendees:~~

Project Manager
ILI Program Manager
Manager of Technical Services or Pipeline Engineering
ILI Technical Consultant
Senior Corrosion Engineer
Pipeline Engineer of the area
Crew member familiar with the pipeline
ILI Engineer
Estimator

3.9.4 **Changes:** Changes agreed upon in the meeting(s) should be documented on the Pre-assessments forms.

3.10 **Pre-assessment Report**

3.10.1 **Report:** The report **shall** have the following data and have been incorporated with the changes from the Pre-assessment meeting described in paragraph 3.9. All required forms **shall** be signed and dated by the ILI Program Manager.

- ILI Request Information
- GIS Maps

- DATA ELEMENT CHECK SHEET (Form A)
- SUFFICIENT DATA ANALYSIS FORM (Form B)
- FEASIBILITY ANALYSIS FORM (Form C)
- Scope of work to modify pipeline, if applicable
- The proposed inspection tool requirements

3.10.2 Review, Approval and Filing: The report shall be reviewed and approved by the ILI Program Manager. A copy shall then be kept in the project file.

3.11 Pipeline Retrofit

3.11.1 Purpose: The step is to do necessary physical modification to make the pipeline piggable and install launcher and receiver.

3.11.2 Retrofit Plan: The ILI Program Manager shall prepare a plan including funding, resource, engineering design and construction for the retrofit. The retrofit phase of a pipeline to be pigged for the first time may take more than a year to complete.

4.0 IN-LINE INSPECTION

4.1 Objectives: The objectives of the In-Line Inspection process are to:
Clean the pipeline adequately for inspection
Geometrically inspect the pipeline for dents or other geometric anomalies
Inspect the pipeline for corrosion or other metal loss anomalies
Map the pipeline to assure correct alignment and ability to locate anomalies
Obtain ILI vendor report that will locate and quantify the severity of damage to the pipe wall and identify other anomalies

4.2 Selection and Marking of Above-Ground Markers (AGM)

4.2.1 Objective: Prior to conducting an In-Line Inspection, the location of above ground markers shall be identified in the field and centimeter accuracy GPS coordinates obtained for these locations along with the depth of cover. ~~A minimum of one AGM should be established approximately every~~ mile. Markers shall be established in the field to identify the physical location of the AGMs. GIS themes shall be created for all AGMs and stored in GIS.

4.2.2 Type of AGMs: AGMs can be established every mile by utilizing one of the following:

4.2.2.1 Significant bends, taps, valves, above ground crossings, wall thickness changes or the start of casings that can be accurately located in the field

4.2.2.2 Pre-selected GPS locations for "pig trackers"

4.2.3 Documentation: The location and method of marking shall be indicated on the IN-LINE INSPECTION ABOVE GROUND MARKER LOCATIONS form (Form D)

4.3 Preparation for In-Line Inspections

4.3.1 Specifications:

4.3.1.1 Each ILI Project shall have a written specification prepared for cleaning. These specifications shall provide adequate information to ensure the pipeline is cleaned to meet the ILIT inspection requirements.

4.3.1.2 Each ILI Project **shall** have a written specification prepared for ILI. This specification **shall** provide adequate information to ensure the vendor's inspection results meet the integrity assessment requirements. As a minimum the specification **shall** include the following:

- **Safety:** The vendor **shall** meet PG&E's specified minimum requirements.
- **Sizing Accuracy:** The required anomaly sizing **shall** be specified to determine an acceptable inspection. Allowable exceptions to the accuracy may be specified to account for short distances of speed excursions, etc.
- **Caliper Accuracy:** The required anomaly sizing **shall** be specified to determine an acceptable inspection. Inspection **shall** be performed to collect data on dents, ovalities, or other geometric features that impact the integrity of the pipeline.
- **Geospatial Accuracy:** Where practical, in addition to collecting the data about the condition of the pipe wall, all In-Line Inspections will also collect geospatial information throughout the survey. The geospatial information should enable the coordinate location of all anomalies, pipe joints, the location of all pipeline appurtenances, and the accurate development of the pipeline profile. The aboveground markers will be used to georeference the data to a horizontal accuracy of +/- 3'.
- **Operator Qualifications:** Documentation needed to verify the competency of the vendor personnel who calibrate and operate the ILIT and analyze the data, including required training and testing. (ASNT No. ILI-PQ-2003)
- **Schedule:** Required immediate repair anomaly report as they are identified and 90-day response time for final report.
- **Report Format:** Data required in immediate repair anomaly report, final report, and the data format.

4.3.2 **Contract:**

- PG&E **shall** follow existing corporate contracting guidelines, including sending out a request for proposal to qualified cleaning and inspection vendors, evaluating bids and contracting for cleaning, inspection and mapping of the pipeline.
- **Vendor Qualification:** A PG&E ILI Team **shall** review and approve the vendor's qualification noting any exceptions to the minimum requirements (Form E).

4.3.3 **In-Line Inspection Plan Review:** The Project Manager **shall** assemble and submit an In-Line Inspection Plan to the ILI Program Manager for review.

4.3.3.1 **Plan contents:** The plan **shall** have the following documents:

- In-Line Inspection Above Ground Marker Location Form (Form D)

- ILI Vendor Qualification Form (Form E)
- ILI Specification(s)
- ILI Contract
- Schedule

4.4 In-Line Inspection Field Operations

4.4.1 **In-Line Inspection Field Meeting:** The Project Manager **shall** conduct a field meeting with the ILI vendor and the personnel supporting the inspection. At this meeting they should cover the following while referring to the ILI Contract, GIS Maps as well as other documents prior to the inspection run:

- **ILI Access:** View the launch and receipt points for the ILI.
- **ILI Procedure:** Review contractor's process and clarify the support PG&E will provide during the run.
- **Access to Above Ground Markers (AGM):** Ensure the contractor is familiar with accessing each (AGM) and has the maps necessary to return to those locations.
- **Tracking:** Review which party is responsible for pig tracking.
- **Schedule:** What exact dates and times the vendor will conduct the inspection.
- **Landowner Contact:** Provide Landowner notification information that will be sent to properties that will be accessed by PG&E or Contractor personnel. Also discuss protocol if landowners question field personnel.
- **Safety and Environmental Hazards:** Discuss safety hazards, such as traffic, overhead lines, rectifier potentials, flora and fauna and other environmental concerns.
- **Notification Procedure:** The vendor **shall** notify the Project Manager when abnormal conditions or situations develop.

4.4.2 **Operation Safety:** PG&E shall follow all existing CGT Clearance Procedure S4420 requirements in launching, running and receiving pigs. These procedures detail clearance points, use man-on-line tags, etc.

4.4.3 **Contamination Prevention:** PG&E **shall** develop and implement a plan to collect and remove debris generated from cleaning and inspection operations and to minimize debris spreading to off-line taps and downstream customers on the pipeline. This plan may require the installation of filters and/or separators at receiver location or at major off-line taps. It may also require that taps be closed for the duration of the pigging project or pig run or temporarily closed during pig passage.

4.4.4 **Customer Service:** PG&E **shall** develop and implement a plan to accommodate customers being fed from pipeline to the extent reasonable and practical. These options may include temporary shutdown, back feed, cross-tie or alternative gas supply via CNG or LNG.

4.4.5 **Pig Tracking:** PG&E **shall** track all pigs which are run in the pipeline at spacing intervals adequate to ensure that pigs are operating within velocity parameters of cleaning or inspection requirements and to maintain the ability to locate the pig within the pipeline should it become lodged or damaged.

4.4.6 **Vendor Performance:** The In-Line Inspections shall be performed strictly in accordance with the approved specification. Any significant deviation from the specification shall be approved and documented in the EXCEPTION PROCESS (Form M) of this procedure described in Section 7.

4.4.7 **Verification of ILI Quality:** Prior to leaving the site, the ILI contractor shall verify that the run was of sufficient quality to ensure meaningful data about the anomalies and to meet the sizing accuracy and the geospatial requirements. The Project Manager should document variances and PG&E's acceptance of these variances.

4.4.8 **Liquid Collection:** Collect liquid sample at the pig receiver per GS&S O-16 Attachment 2 for each pigging project. The liquid sample is needed for testing IC.

5.0 <u>DIRECT EXAMINATION</u>

For a typical Direct Examination Process see the flow chart shown in Attachment A.

5.1 **Objective:** The objective of the Direct Examination phase is to:

- Gather data to validate the ILI Vendor's Report
- Verify the pipeline's integrity
- Perform necessary repairs
- Restore the pipeline's MAOP, if required
- Determine the root cause of corrosion or damage
- Complete an ILI Project Report

5.2 **Immediate Anomaly Discovery and Final ILI Vendor Report:** The contractor shall notify PG&E immediately when anomalies that are described by CFR 49, Part 192, Section O, as "Immediate repair conditions" are identified (Table 5.5.1). The date of discovery of an "Immediate" anomaly shall be considered either the notification date of "Immediate" anomalies or the receipt of the Final ILI Vendor Report. No later than 180 days after the date of the successful final ILI run, the ILI contractor shall submit a final report. The final report shall integrate the geometry, metal loss, and any other ILI tools used, addressing internal corrosion, external corrosion and mechanical damage per the ILI specification.

5.3 **Pressure Reduction Review Process:** As soon as possible but not exceeding 5 calendar days of receipt of the immediate anomalies report, the ILI engineer shall review the anomalies and take proper action to ensure pipeline safety according to the following steps:

5.3.1 **Create a list of "Immediate" anomalies:** The ILI engineer **shall** review the immediate anomalies reported by the ILI contractor and document them on Form F. This Form **shall** be completed even though there are no immediate anomalies.

5.3.2 **Verify pipe specifications and re-assess each anomaly on Form F:** The ILI engineer **shall** determine the approximate location of each "Immediate" anomaly and **shall** determine the HCAs and identify the relative consequences (class location, structures, etc.) in the vicinity of the anomaly, determine the actual pipe specifications and use RSTRENG or equivalent effective area method to assess the ILI tool Pf. Record the highest Pf value from RSTRENG or equivalent effective area method calculation of each anomaly and prioritize the anomalies on Form F. If there are no "Immediate" anomalies remaining on the list. Proceed to Section 5.5.

5.3.3 **Pressure Reduction:** If there are any "Immediate" anomalies left on Form F after assessment of Pf, immediately reduce the operating pressure according to the following steps:

5.3.3.1 **Determine Pdiscovery (Pdis):** Pdis is defined as the pipeline pressure at the time the condition was discovered and for the purpose of this procedure the highest pipeline operating pressure during the ILI run or the highest operating pressure either between the ILI run and the time the immediate anomalies are identified will be used. This pressure **shall** be recorded on Form F. (Note: It is not appropriate to spike the operating pressure prior to making a definitive call on immediates.)

5.3.3.2 **Pressure Reduction Limits:**

- If there are any non-corrosion anomalies with metal loss or corrosion anomaly with metal loss greater than 80% of the wall thickness on Form F, the operating pressure shall be reduced to 80% of Pdis and proceed with Section 5.3.4.
- For remaining corrosion anomalies on Form F proceed with the following; calculate Ps by multiplying the Pf value by the class location design factor and record the pressure on Form F. The operating pressure **shall** be reduced to the highest of 80% of Pdis or the lowest Ps of all the anomalies.

5.3.4 **Operational/Pressure Change Notification:** If operational or pressure changes are required, the ILI Program Manager **shall** notify the GT&D GE Director, the Pipeline Engineering Manager and the Technical Services Manager. He **shall** communicate and document all required operational/pressure changes including over pressure protection system (Utility Work Procedure WP4430-07) and alarm settings to Gas System Operations (GSO) on Form F.

5.3.5 **Operational/Pressure Change Implementation:** GSO **shall** execute and order the required changes and the responsible superintendent **shall** ensure that the changes executed by GSO are implemented immediately. The ILI Engineer **shall** review UO Standard 4413 to determine if additional reporting is required to the CPUC/OPS (*e.g. A Safety Related Condition report should be filed in accordance with that standard if pipeline pressure must be reduced by 20% or more due to damage found and there is a structure within 660 feet of the damage location).* The documentation of pressure reduction and resetting alarm settings implementation shall be kept in file, including Gas Log System (GLS) record.

5.3.6 **Inability of Reducing Pressure:** When pressure reduction is not feasible, PM shall file an exception report and notify CPUC/OPS per Section 7 of this Procedure.

5.3.7 **Extension of Pressure Reduction Time Limit:** When it is required to maintain pressure reduction time exceeds 365 days, the ILI engineer shall write a technical justification of no jeopardy to public safety and file it in the final ILI report and follow exception process per Section 7 of this procedure.

5.4 **Immediate Anomaly Inspection/Repair Plan :** If the pressure of the pipeline needs to be restored prior to the receipt and verification of the Final ILI Report, the ILI Engineer shall prepare and submit Form G - Anomaly Prioritization and Direct Examination Form (Inspection/Repair Plan) to the ILI Program Manager and the Manager of Technical Services.

5.4.1 **Field Inspection:** The Project Manager is responsible for all project management aspects of implementing the Inspection/Repair Plan. See Section 5.5, for details.

5.4.2 **Root Cause Analysis:** The ILI Engineer shall ensure all data are collected to support the Root Cause Analysis. (See Section 5.8)

5.4.3 **Operational/Pressure Change Concurrence:** After all Immediate anomalies are inspected/repaired; the ILI Program Manager **shall** evaluate the repairs and determine the timing of restoring the MAOP. He **shall** then gain concurrence from the GSM&TS Manager of Pipeline Engineering and the Manager of Technical Services to restore the MAOP, communicate and document all required operational/pressure changes to Gas System Operations (GSO).

5.4.4 **Operational/Pressure Change:** GSO **shall** execute and order the required changes and the responsible district superintendent **shall** ensure that the changes executed by GSO are implemented per Utility Work Procedure WP4430-07.

5.5 **Inspection/Repair Plan :** Within 90 days of receipt of the final report, the ILI Engineer **shall** prepare an inspection plan and submit to the ILI Program Manager and the Manger of Technical Services. The inspection plan shall be documented on Form G. In developing the inspection plan the tool tolerances per RMP File 7.11 (PG&E White Paper on Pf* Calculations Using ILI Data) shall be added to the anomalies for the Pf* calculations

5.5.1 **Prioritization of Anomalies:** For each In-Line Inspection, the anomalies **shall** be prioritized following the criteria in Table 5.5.1. All anomalies prioritized, as Immediate, Scheduled-one year and scheduled-other, shall be recorded on Form G.

Table 5.5.1 In-Line Inspection Tool Anomaly and Direct Anomaly Prioritization Guide

%SMYS at MAOP	Immediate	Scheduled - One Year	Scheduled - Other	Monitored
At or above 50%	• Pf/MAOP <=1.1 • Dents with metal loss, cracks or a stress riser • PG&E's judgment • SCC • Metal loss affecting long seam formed by direct current, low frequency ERW or electric flash welding. • Metal Loss > 80% W.T.	• A smooth dent with depth greater than 6% (0.5" in depth dent for less than 12" diameter pipe) • A smooth dent with depth greater than 2% (0.25" in depth dent for less than 12" diameter pipe) that affects girth weld or long seam	• Pf*/MAOP <=1.39 • PG&E's Judgment	• All scheduled dents that engineering analyses demonstrate critical strain levels are not exceeded and left in place
30% to 50%	• Pf/MAOP <=1.1 • Dents with metal loss, cracks or a stress riser • PG&E's judgment • SCC • Metal loss affecting long seam formed by direct current, low frequency ERW or electric flash welding. • Metal Loss > 80% W.T.	• A smooth dent with depth greater than 6% (0.5" in depth dent for less than 12" diameter pipe) • A smooth dent with depth greater than 2% (0.25" in depth dent for less than 12" diameter pipe) that affects girth weld or long seam	• Pf*/MAOP <=2.0 • PG&E's Judgment	• All scheduled dents that engineering analyses demonstrate critical strain levels are not exceeded and left in place
Less than 30%	• Pf/MAOP <=1.1 • Dents with metal loss, cracks or a stress riser • PG&E's judgment • SCC • Metal loss affecting long seam formed by direct current, low frequency ERW or electric flash welding. • Metal Loss > 80% W.T.	• A smooth dent with depth greater than 6% (0.5" in depth dent for less than 12" diameter pipe) • A smooth dent with depth greater than 2% (0.25" in depth dent for less than 12" diameter pipe) that affects girth weld or long seam	• Pf*/MAOP <=3.3 • PG&E's Judgment	• All scheduled dents that engineering analyses demonstrate critical strain levels are not exceeded and left in place

d/t – Defect depth to wall thickness ratio

5.5.2 Number of Excavations: The inspection plan **shall** specify the number and location of excavations. The required excavations are as follows

- **"Immediate":** All Immediate anomalies (See Table 5.5.1) **shall** be excavated for direct examination.
- **"Scheduled-one year":** All Scheduled-one year anomalies (See Table 5.5.1) **shall** be excavated for direct examination.
- **"Scheduled-other":** All scheduled-other anomalies (See Table 5.5.1) **shall** be included in the inspection plan. If the Integrity Mgmt Program Manager approves a shorter re-inspection interval, then, a lower Pf/MAOP value can be used that allows them to be Monitored until next scheduled re-inspection, per Figure 5.5.2
- **"Monitored":** No Monitored anomalies (See Table 5.5.1) are required to be excavated under these specifications. These anomalies must be recorded and compared to themselves during future inspections.
- **Minimum Excavations:** A minimum of two excavations **shall** be made for each ILI run. If two excavations are not sufficient to validate the ILI data, more excavations **shall** be performed.

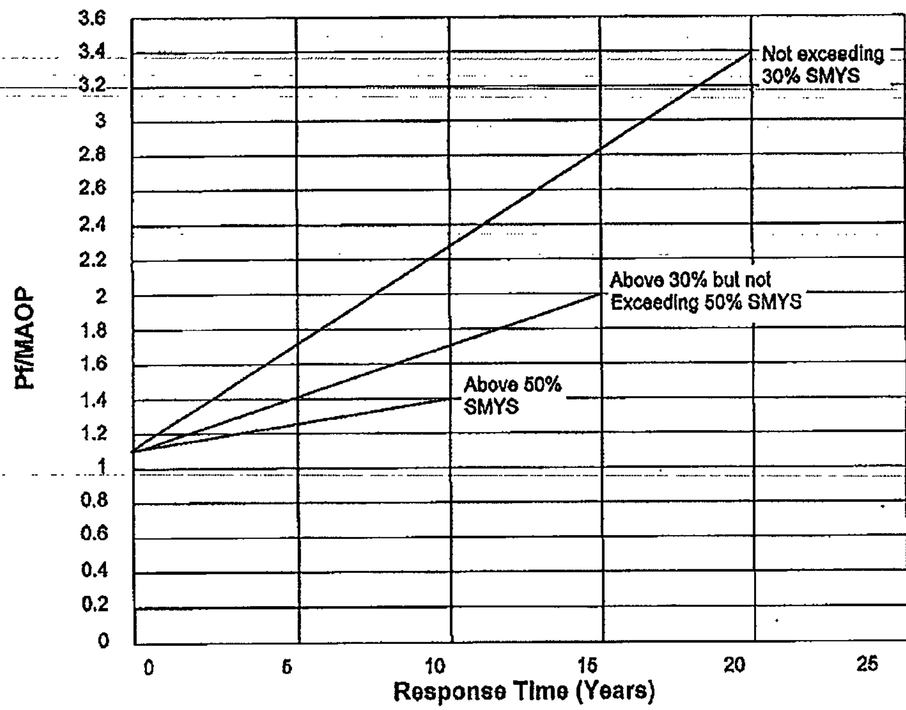

Figure 5.5.2
(ASME B31.8S-2001, Section 7, Figure 4)
TIMING FOR SCHEDULED RESPONSES—TIME DEPENDENT THREATS
PRESCRIPTIVE INTEGRITY MANAGEMENT PLAN

5.5.3 **Tool Tolerance Consideration:** In selecting anomalies/clusters of corrosion for excavation, inspection and /or repair in order to gain maximum re-inspection interval, the ILI vendor tool tolerance should be added to the anomalies for calculating the Pf* per RMP File 7.11 (PG&E White Paper on Pf* Calculations Using ILI Data.)

5.5.4 **Documentation:** The Inspection Plan (Form G) **shall** be reviewed and approved by the ILI Program Manager and the Manager of Technical Services or his designate.

5.6 **Field Examination :** All Immediate anomalies on Form G shall be excavated, examined and repaired/pipe replaced not exceeding 365 days from the pressure reduction date (Form F) and the remaining Scheduled – one year and Scheduled – other anomalies on Form G shall be completed within 365 days of receipt of the final report from the ILI vendor (For the purpose of the procedure, the date shown on the ILI vendor's report will be used). Repair decisions made following excavation and examination are documented on Form I. If any of the required excavations or repairs can not be completed within 365 days, the PM shall complete an exception report (Form M) per Section 7 of this Procedure.

The field examination addresses any Immediate, Scheduled – one year, and selected Scheduled – other anomalies in the Inspection Plan. It also validates the In-Line Inspection Vendor's Report. The process includes:

- Scheduling the excavations

- Excavating the anomalies and collecting data at the identified locations
- Comparing the field data with ILI data
- Evaluating remaining strength of the pipe segment
- Performing repairs, if needed

5.6.1 **Scheduling the Excavations:** The ILI Project Manager is responsible for scheduling the excavations to ensure that they are performed with consideration of the order determined in section 5.5 and consideration of the excavation efficiency.

5.6.2 **Pipe Excavation and Data Collection:** The ILI Project Manager **shall** schedule and monitor the excavations, until all excavations needed to validate the re-inspection interval are completed. The pipe **shall** be excavated in accordance with PG&E Utility Operations Guideline G14413 "*Procedure for Excavating Pipeline and Services.*" In addition, the following requirements **shall** be met:

- **Location and Size of Excavation:** The location and size of the excavation site **shall** be identified and recorded on Form H: EXCAVATION DATA SHEET. Each end of the excavation **shall** be located and recorded with a GPS instrument. The length of the excavation **shall** be physically measured and recorded on Form H.
- **Data Collection:** Collecting data on the condition of the coating and the pipe at the excavation site is a key step of the ILI process. Either company personnel and/or the contractor can perform the data collection. The data that is to be collected for Form H is identified in Table 5.6.2. All excavation sites shall include wet magnetic particle inspection to test for SCC.

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TABLE 5.6.2 DIRECT EXAMINATION DATA COLLECTION REQUIREMENTS (FORM H)

Data Element	DATA Type	Required	Description
1.0 Before Coating Removal			
1.1	Native Soil Type	R	Check the appropriate box to determine the type of soil the pipe is bedded in. The reference location shall be the middle of the bellhole length at the springline location. Also, in the comments section record the type of soil the pipe is bedded in using the USC classification system. Clayey Loam, clayey sandy loam, etc.
1.2	Existing Coating Type	R	Report the existing coating type, its approximate thickness, and the number of layers. For reference use the middle of the excavation length at the springline of the pipe.
1.3	Holiday Testing	R	This test allows for electrical identification of location and size of coating holidays, and is particularly valuable in identifying areas to pay special attention to during coating removal. The holidays should be mapped electrically unless the coating is sufficiently degraded to where it is obvious where the holidays are. These areas could provide significant evidence and help in determining the root cause of any corrosion that is found. In addition these areas could be critical in determining if the corrosion is active or inactive.
1.4	Measurement of pipe to soil potential	R	These measurements shall be performed in accordance with NACE Standard TM0497. The reference electrode shall be placed in the bank of the excavation within 1-2 inches of the coating. These potentials may help identify dynamic stray currents, as well as help in determining the root cause of any corrosion present (active vs. inactive).
1.5	Soil Resistivity	R	Soil resistivity measurements: (1) 4-pin method: The pin alignment shall be taken transverse to the pipe. The nearest probe shall be at least 10 feet from the pipe. Pin spacing shall approximate the pipe centerline depth. This is intended to be a measurement of native (original) soil conditions. (2) Soil Box: The soil desired here is that in which the pipe is bedded at the springline location in the middle of the excavation length. Note whether the soil is native or sand.
1.6	Soil Sample	R	The soil immediately adjacent to the pipe surface shall be collected with a clean spatula or trowel and placed in a 16 oz. plastic jar with a plastic lid. The soil desired here is that in which the pipe is bedded at the springline location in the middle of the excavation length. In some cases special samples must be obtained in-situ using a "spoon" that will keep the sample confined. The data will be used for determining the soil corrosivity using a risk based weight-function model, and should be used for prioritizing excavations within the same priority. The sample jar should be packed full to displace as much air as possible. Tightly close the jar, seal with plastic tape or equivalent and using a permanent marker or label to record the sample location on both jar and lid. See Appendix C
1.7	Groundwater Samples	R	Take groundwater samples if water is present in the excavation. Water should always be collected from the open ditch when possible. Completely fill the plastic jar and seal and identify location as described above. For special situations it will be used for determining the bulk groundwater chemical properties.
1.8	Coating Condition	R	Document the general coating condition. Three conditions could exist (1) Coating is in good condition and completely adhered to pipe; (2) Coating partially disbonded and/or degraded; (3) The coating is significantly disbonded or missing, i.e., most of it comes off with the soil.
1.9	Map Of Coating Degradation	R	Note in the map the location of all coating holidays, calcareous deposits, etc. The zero reference shall be the farthest upstream location that is inspected.
1.10	Photo documentation	R	Document the coating condition with a digital camera. Photos shall have ruler or other device to determine magnification of photographs showing details of the pipe and coating condition. The minimum requirements shall be to document the following: • The type of cover • Macros showing the cross-section of the excavation (depth of pavement, soil strata, etc.); cross section showing the strata under the pipe especially if rocks are present. • Macros of areas where the jeep test shows holidays • As-found condition of the coating after excavation is complete • General condition of coating • Showing the overall presence or absence of calcareous deposits after the coating has been completely removed but prior to sandblasting. • Presence or absence of rocks embedded in the coating (preferably at the 6:00 position) • Pitting before and after sandblasting • Any unusual characteristics of the pipe or excavation • After recoating • Documenting the as-left condition of the site Macro as well as perspective views shall be recorded. The photo log on page 9 of 10 of the H-form shall be filled out with any necessary descriptions of the photographed areas.

Data Element	DATA Type	Required	Description
1.11	Coating Sample	R	Two samples of the coating shall be obtained. One will be sent to a lab for asbestos testing. The other sample will be stored for physical examination and aid in determining root cause. This sample may also be used to determine the electrical and physical properties of the coating as well as for performing microbial tests. This sample shall be obtained from an area where the worst pipe damage was found, if possible. This sample shall be given to the FES or designate
1.12	Under coating liquid pH analysis	R	If any liquid is detected underneath the coating the pH shall be determined with pH litmus paper. This test infers the relative level of CP reaching the pipe surface.
1.13	Corrosion Product Removal	R	Carefully remove any corrosion deposit for analysis. The presence or absence of corrosive species in the corrosion products can guide the root cause analysis. Analysis may include, but is not limited to, MIC testing, chemical testing, and in some cases XRD testing.
1.14	Soil pH	R	Obtain soil pH reading at the upstream end downstream ends of the bell hole using the Sb electrode. This must be done in the soil the pipe is bedded in. Helps determine the corrosivity of the soil.
2.0 After Coating Removal			
2.1	Pipe Temperature & Pipe Diameter	D	Measure the bare pipe surface temperature. This factors into the tendency for coating to disbond and SCC susceptibility. Measure the circumference of the pipe using a pi tape or other suitable device and compute the actual outside diameter of the pipe.
2.2	Weld Seam Identification	D	The type of weld seam shall be identified and recorded. It will be used to compare with GSAVE, and the presence of brittle seam welds could also be determined. If the seam type cannot be determined, check that box. In some cases it will be necessary to perform a macro etch to locate and characterize the weld type and condition. The macro will only be done when specifically called for by the FES or designate Recoating of the pipe and backfilling of the bell hole will not be allowed unless the long seam has been identified or there is no external corrosion.
2.3	Girth Weld Coordinates	R for ILI	This is required for ILI inspections. ILI keys on the nearest girth weld to determine the location of the bell hole and to compare to ILI girth weld data.
2.4	Other Damage	R	Other damage to the pipe surface that can be visually detected shall be recorded, and immediately reported to PG&E. Examples of such damage would include gouges, cracking, dents and out of roundness.
2.5	UT Wall Thickness Measurements	R	Ultrasonic wall thickness shall be taken at every quadrant on the pipe to establish original/nominal wall thickness. In cases where an ICDA pre-assessment has been performed, a UT grid shall also be obtained at the 6:00 location for a length of 1-foot circumferential by 1-foot axial. Grid size shall be 1"x1". The minimum thickness measured in each grid box shall be recorded. The grid shall be located at the low end of the pipe. This ICDA grid and angle of inclination shall be recorded on page 6 of 10 on the H-form.
2.6	Wet Fluorescent Magnetic Particle Inspection	R	For determining the presence or absence of SCC this test shall be performed. Only the AC yoke method shall be used. Surface preparation shall be light sandblasting. On occasion the FES or designate may require walnut shell blasting. Dry powder methods are not acceptable. Direct electric current methods are not acceptable. All indications shall be photo documented under both black and white light and the photos included in the report. The PG&E PM shall be notified immediately of any indications found.
2.7	Photographic Documentation of Corroded Area	R	The corroded surface shall be photographed, preferably with a digital camera to document the morphology and extent of the corrosion. The photo log on page 9 of 10 of the H-form shall be filled out with any necessary descriptions of the photographed areas.
2.8	Overview Map Of Corroded Area.	R	An overview map of the corroded area shall be sketched out onto the form. Enough detail shall be included to sufficiently document where and how large the corroded areas are. The zero reference point shall be the farthest upstream location that is inspected.
Page 3 of 10	Excavation Drawing	D	The pipeline inclination angle and the depth profile shall be measured and recorded at each end and in the middle of the bell hole. The inclination angle shall be recorded in the boxes above the grid, and the depth profile shall be measured and documented in the grid.
Pages 4 of 10 and 5 of 10 of the H-Form	Pit Depth Measurement Grid Sheets	R	Corrosion damage shall be measured with sufficient detail to enable accurate RSTRENG analyses of the corrosion area. A grid of wall loss measurements shall be taken over the entire corroded areas. The grid shall be oriented so that columns are circumferentially oriented on the pipe and the rows lie parallel to the longitudinal axis of the pipe. The grid size should be sufficiently fine to document the variation of wall thickness but in no case shall be greater than a one-inch mesh. The grids shall be documented on pages 4 of 10 and 5 of 10 on the H-Form.
3.0	**Pipe Recoat Data**		
3.1	Sandblast Media	R	Record the type of media used – sand, grit, or copper slag are all acceptable. Use of shot is prohibited. Also record the final anchor profile measurement using the TesTex Press-O-Film tape method.

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Data Element	DATA Type	Required	Description
3.2	Re-coating Type	R	Record the coating type used to recoat the pipe.
3.3	Environmental Conditions	R	Document the relative humidity, temp, dew point, etc., at the time of coating. For epoxy systems, the pipe must be over 60 degrees F, at least 5 degrees F above the dew point and the relative humidity must be less than 80%.
3.4	Repair Coating Hardness	R	For epoxy systems measure and record the final hardness before the pipe has been released for burial.
3.5	Coating Thickness	R	Measure the coating thickness at the locations given. Each clock position listed shall be the average of 3 readings within a 4 cm circle. The repair coating shall be holiday tested and all holidays must be repaired and retested. It is preferable to repair holidays using the same coating system, although alternative repair systems can be acceptable. The PG&E FES or designate must approve all alternative repair systems.
3.6	Coupon Test Station Installation	R	Document the type of test station left behind. For coupons, it is recommended that the commissioning should begin no sooner than 3 months after installation. The test station should be installed at the extreme end of the bell hole adjacent to or in the "old" coating that is NOT being reconditioned.
3.7	Backfill Material	R	Note what material was used for backfill and whether or not pipe protection was used.
3.8	P/S Readings	R	Perform at least 1 P/S on reading over the pipeline after backfilling but BEFORE paving or any concrete work is done. In some cases perform a local "on" survey and record the results.
3.9	Site Sketch	R	A sketch of the site arrangement shall be made, showing the inspected area as well as measured distances from physical features such as roads, buildings, distance from upstream girth weld (if available), etc. The purpose would be to be able to determine the location using physical markers in the field (without using GPS) should the area be paved over, and to confirm the locations of those structures in GSAVE.

5.6.3 **Evaluating Remaining Strength:** The RSTRENG or KAPA (Failure pressure calculation software developed by Kiefner & Associates) calculations are performed and the summary is recorded on Form I "DIRECT EXAMINATION SUMMARY" for the exposed corroded areas to evaluate the remaining strength of the pipe. The RSTRENG or KAPA calculations are used to determine the following:

- **Predicted Failure Pressure:** A Pf **shall** be calculated using RSTRENG or KAPA for each corroded area that is direct examined and determine if action needs to be taken. Other analytical techniques may be used if approved by the Manager of Technical Services or his designate. An individual trained and qualified to use RSTRENG or KAPA **shall** make these calculations. Records of the qualification **shall** be maintained in the Integrity Management Program file.
- **Reassessment Interval:** The ratio of Pf/MAOP of the field examined anomalies and Pf*/MAOP of the un-examined anomalies remaining on the pipeline (Table 5.6.5) are key factors in determining the reassessment interval.

5.6.4 **Comparing Field Data with ILIT Data:** A comparison shall be made between field data and ILI data; and to be provided as input for the Long Term Integrity Management Plan.

5.6.5 **Performing Repairs on Excavated Anomalies:** In general, all corroded areas with *Pf* less than those shown in Table 5.6.5 **shall** be repaired so that the maximum re-inspection interval can be achieved. ILI Engineer to inform Pipeline Engineer and follow the Utility Work Procedure WP4100-05 to determine if and how the anomalies should be repaired. Any exceptions **shall** be documented on Form M "EXCEPTION REPORT" and approved by the Manager of Technical Services.

TABLE 5.6.5 MINIMUM PF TO JUSTIFY MAXIMUM RE-INSPECTION INTERVAL[3]

CRITERIA		
AT OR ABOVE 50% SMYS	AT OR ABOVE 30% UP TO 50%	LESS THAN 30% SMYS
Pf above 1.39 times MAOP	*Pf* above 2.0 times MAOP	*Pf* above 3.3 times MAOP

5.7 **MAOP Restoration Review/Concurrence :** If the pipeline pressure has been reduced, the ILI Program Manager **shall** evaluate the repairs and determine the timing of restoring the MAOP. He **shall** notify GT&D GE Director and the Manager of Technical Services, and gain concurrence from the Manager of Pipeline Engineering and the Manager of Technical Services to restore the MAOP, communicate and document all required operational/pressure changes to Gas System Operations (GSO).

5.7.1 **Operational/Pressure Change:** GSO **shall** execute and order the required changes and the responsible district superintendent or T&R Supervisor **shall** ensure that the changes executed by GSO are implemented.

[3] ASME B31.8S 2004, *Supplement to B31.8 on Managing System Integrity of Gas Pipelines*, Section 7, Figure 4

5.8 Root Cause Analysis

Procedure: The ILI Project Manager **shall** ensure that a root cause analysis is performed on all Direct Examined pipe. Where it is determined that a significant number of direct examined anomalies are due to the same cause, a common single root cause report shall be sufficient. Where multiple causes are implicated, the number of root cause investigation shall be increased to adequately document the individual causes.

Documentation: The root cause of all Direct Examined pipe **shall** be documented on Form K "ROOT CAUSE ANALYSIS REPORT" and be completed within 90 days of receipt of the field examination report.

5.8.1 **Description of Damage:** Types of damage observed e.g. coating, pipe, and damage mechanism (external corrosion, third party, etc.).

5.8.2 **Extent of Damage:** Review GIS and other historical maintenance data to determine if they may assist in quantifying the extent of the damage or the needed extent of the mitigation activities.

5.8.3 **Review of Existing Damage Mitigation Measures:** Review of the existing mitigative measures that should address the threat causing the damage. Describe any problems with existing mitigation.

5.8.4 **Root Cause of Damage:** As a result of the review of the damage, historical data, and the existing mitigative measures, describe the root cause of the damage found.

5.8.5 **Review of Damage Mitigation Measures Taken:** Describe the actions taken to mitigate the damage found as a result of the ILI.

5.8.6 **Evaluation of additional Mitigation Efforts:** Describe any additional mitigation efforts that may help address the root cause of the damage. This may include coating replacement, the installation of additional CP, Landowner notifications, etc.

5.8.7 **Evaluation of need for additional testing:** If the root cause analysis identifies a mechanism that the ILI process is not well suited to detect, then ~~it shall be documented on Form M and brought to the attention of the~~ Manager of Technical Services.

5.9 **RMP-11 Final Report :** This report includes: ILI Vendor Report, Bellhole Inspection Report and PG&E Final Report.

5.9.1 **ILI Vendor Report:** This report includes the hard copy, associated software, and electronic data provided by the ILI vendor.

5.9.2 **Bellhole Inspection Report:** This report includes all "H-Forms" and is provided by the bellhole inspection vendor.

5.9.3 **PG&E Final Report:** Within 45 days after direct examinations and root cause analyses are complete, the ILI engineer **shall** be responsible for developing the PG&E final report. The report **shall** have the following content.

- **Project Summary:** Project Manager **shall** complete a discussion of job details by project phase including lessons learned, results and critiques. (Attach Job estimate)
- **Pre-Assessment:** Documentation of the ILI feasibility, Forms A, B and C, and the Pipeline Features List.

- **ILI Planning:** Documentation of AGM locations, Form D. Documentation of the ILIT vendor qualification, Form E. (Attach ILI specification and ILI contract.)
- **ILIT Operation:** Project Manager shall summarize how the ILIT field operation went. (Attach Tracking Spreadsheet and Clearance Procedure)
- **Direct Examination:** Documentation of all direct examinations, Forms F, G, and I.
- **Post Field Inspection Pipeline Listing:** Pipeline anomalies list with all digs and repairs marked (Excel file).
- **Root Cause Analysis:** Documentation of root cause analysis, Form K
- **Exception:** Documentation of exceptions report, Form M.

5.10 **GIS Anomaly Documentation :** All anomalies listed in the ILI Vendor Report and the Bellhole Inspection Report shall be mapped in GIS including but not limited to the following information for data integration and future monitoring:

- ~~**Geographic Location:** In UTM, Zone 10, NAD83, meters.~~
- **ILI Log Distance**
- **Severity Prioritization:** Whether it is Immediate, Scheduled-one year, Scheduled-other, or Monitored
- **Type of Anomaly:** Ext ML, Int ML, Dent, etc.
- **Relative Location of Anomaly:** Anomaly on pipe, weld or close to girth weld
- **O'clock position:** Location around the circumference
- **Size:** Maximum depth, length and width per ILIT
- **Box:** Cluster and Cluster ID
- **ILIT Pf:** Calculated (Pf) derived from Vendor's ILIT report
- **Direct Examination (Y or N)**
- **Actual Size:** Maximum depth, length and width per direct examination, if available.
- ~~**RSTRENG Pf:** Calculated (Pf) derived from direct examination, if~~ available
- **Pf/MAOP:** Use RSTRENG failure value for Pf, if available. Otherwise, use ILIT report Pf.
- **Record of Repairs:** Type of repair, date of repair, if available
- **Quality Assurance**
- **ILI date:** Date of the ILI run
- **Vendor Name:** ILI Vendor

5.11 **Distribution:** A hard copy of the RMP-11 Final Report shall be provided to the Integrity Management Program Manager for filing in the Integrity Management Library (Kettleman Conference Room 200). Additional copies of the ILI Vendor Report and Bellhole Inspection Report shall be distributed to the following persons:

- **ILI Program Manager**
- **ILI Project Manager**
- **ILI Engineer**
- **Pipeline Engineer responsible for the pipeline**
- **District Superintendent/Distribution T&R Supervisor responsible for the pipeline**

6.0 **POST ASSESSMENT**

Objective: The objective of the Post Assessment process is to develop a Long Term Integrity Management Plan (LTIMP) to mitigate any significant deficiencies identified by the RMP-11 Final Report. The LTIMP **shall** include assigning re-inspection intervals and assessing/monitoring the overall effectiveness of the ILI process.

Responsibility: After completing the RMP-11 Final Report, the ILI Program Manager will turn over the project to the Integrity Management Program Manager who **shall** be responsible for determining and documenting the re-inspection interval, ensuring the re-inspection occurs prior to the end of the interval, and that a project is planned to mitigate any significant deficiencies identified by the RMP-11 Final Report. The Manager of Technical Services **shall** approve the LTIMP.

Documentation: The LTIMP including re-inspection interval for the pipeline segment **shall** be documented in the Integrity Management Areas (IMAs) per RMP-06.

6.1 **Re-Inspection Intervals:** The Integrity Management Program Manager will review the anomalies in the ILI Vendor Report that are not direct examined and the root cause analysis to determine the appropriate re-inspection intervals per Figure 5.5.2 or Maximum re-inspection interval in Table 6.1, and recommend any additional long-term mitigation that needs to be done.

TABLE 6.1 TIMING SCHEDULE RESPONSES – TIME DEPENDENT THREAT[4]

INTERVAL (YEARS)	CRITERIA		
	AT OR ABOVE 50% SMYS	AT OR ABOVE 30% UP TO 50%	LESS THAN 30% SMYS
5	Pf (or Pf*) above 1.25 and <= 1.39 times MAOP	Pf (or Pf*) above 1.4 and <= 1.7 times MAOP	Pf (or Pf*) above 1.7 and <= 2.2 times MAOP
10	Pf (or Pf*) above 1.39 times MAOP	Pf (or Pf*) above 1.7 and <= 2.0 times MAOP	Pf (or Pf*) above 2.2 and <= 2.8 times MAOP
15	Not Allowed	Pf (or Pf*) above 2.0 times MAOP	Pf (or Pf*) above 2.8 and <= 3.3 times MAOP
20	Not Allowed	Not Allowed	Pf (or Pf*) above 3.3 times MAOP

6.2 **Data Integration** The following systems will be updated to ensure on-going data integration

GIS: All anomalies will be incorporated into the ILI anomaly theme. In addition, the Risk Mitigation theme will be updated to reflect the recent inspection of the pipeline segment. If the inspection reveals any data discrepancies in GIS, these will also be updated.

Integrity Management Plan: The integrity management plan for the pipeline segment will be updated to reflect the ILI inspection results.

Integrity Management Schedule: The integrity management schedule will be updated with the re-inspection date for the pipeline segment.

Long-term Mitigation: Mitigation activities will be scheduled to address any significant deficiencies identified by the LTIMP.

[4] ASME B31.8S 2004, *Supplement to B31.8 on Managing System Integrity of Gas Pipelines*, pg. 27-6, Figure 4 (Section 5, Figure 5.5)

7.0 <u>EXCEPTION PROCESS</u>

Objective: The objective of this section is to provide control and documentation of exceptions taken. This control and documentation is required to ensure the compliance with the ILI process, to continuously improve the process by providing feedback, and to have an auditable trail. It is expected that all requirements of this procedure be met in conducting an ILI. However, when it is not feasible to meet certain requirements then exceptions can be taken by obtaining approval; and documenting the exceptions as prescribed in this section.

Documentation: Document the above steps on Form M - EXCEPTION REPORT. Include all exception reports in the PG&E Final Report.

7.1 **Exception Requirements:** The following process is required for taking an exception with this procedure. It **shall** be documented on Form M - EXCEPTION REPORT:

- **Paragraph Number of Exception:** State the specific paragraph number where the exception is being taken.
- **Requirements of Paragraph:** Briefly state in your own words the requirements of the paragraph.
- **Alternative Plan:** To state what is proposed instead of what is required in the procedure.
- **Reason for Exception:** Provide the reason the exception is needed.
- **Recommendation:** Indicate if it is recommended to change the procedure or if this exception is project specific.
- **Approval:** Obtain approval from the Manager of Technical Services or his designate prior to acting on the exception.
- **Notification:** Refer to RMP-06, Section 15 for CPUC/OPS notification requirements.

8.0 DOCUMENTATION AND RECORD KEEPING

Purpose: Table 8.0 summarizes the required forms and associated responsibilities.

TABLE 8.0 - DOCUMENTATION AND RECORD KEEPING REQUIREMENTS

PARAGRAPH	FORM	PURPOSE	RESPONSIBILITIES
3.0 PRE-ASSESSMENT	A	Data Element Check List	ILI Engineer
	B	Sufficient Data Analysis	ILI Engineer
	C	Feasibility Analysis	ILI Program Manager ILI Engineer (This form includes the authorization of Forms A&B also.)
4.0 IN-LINE INSPECTION	D	AGM Locations	ILI Engineer
	E	ILI Vendor Qualification Form	ILI Engineer / ILI Program Manager
5.0 DIRECT EXAMINATION	F	Immediate Anomalies Analysis	ILI Engineer / ILI Program Manager
	G	Indication Prioritization and Direct Examination Form (Inspection/Repair Plan)	ILI Engineer ILI Program Manager Manager of Technical Services
	H	Document all immediate and scheduled anomalies	ILI Engineer or Corrosion Engineer
	I	Direct Examination Summary	ILI Program Manager
	J	Left Blank Intentionally	
	K	Root Cause Analysis	Sr Corrosion Engineer Manager of Technical Services
	A thru K and M	PG&E Final Report	ILI Program Manager
6.0 POST ASSESSMENT	L	Left Blank Intentionally	
OTHER	M	Exception Reports	ILI Engineer ILI Program Manager Manager of Technical Services

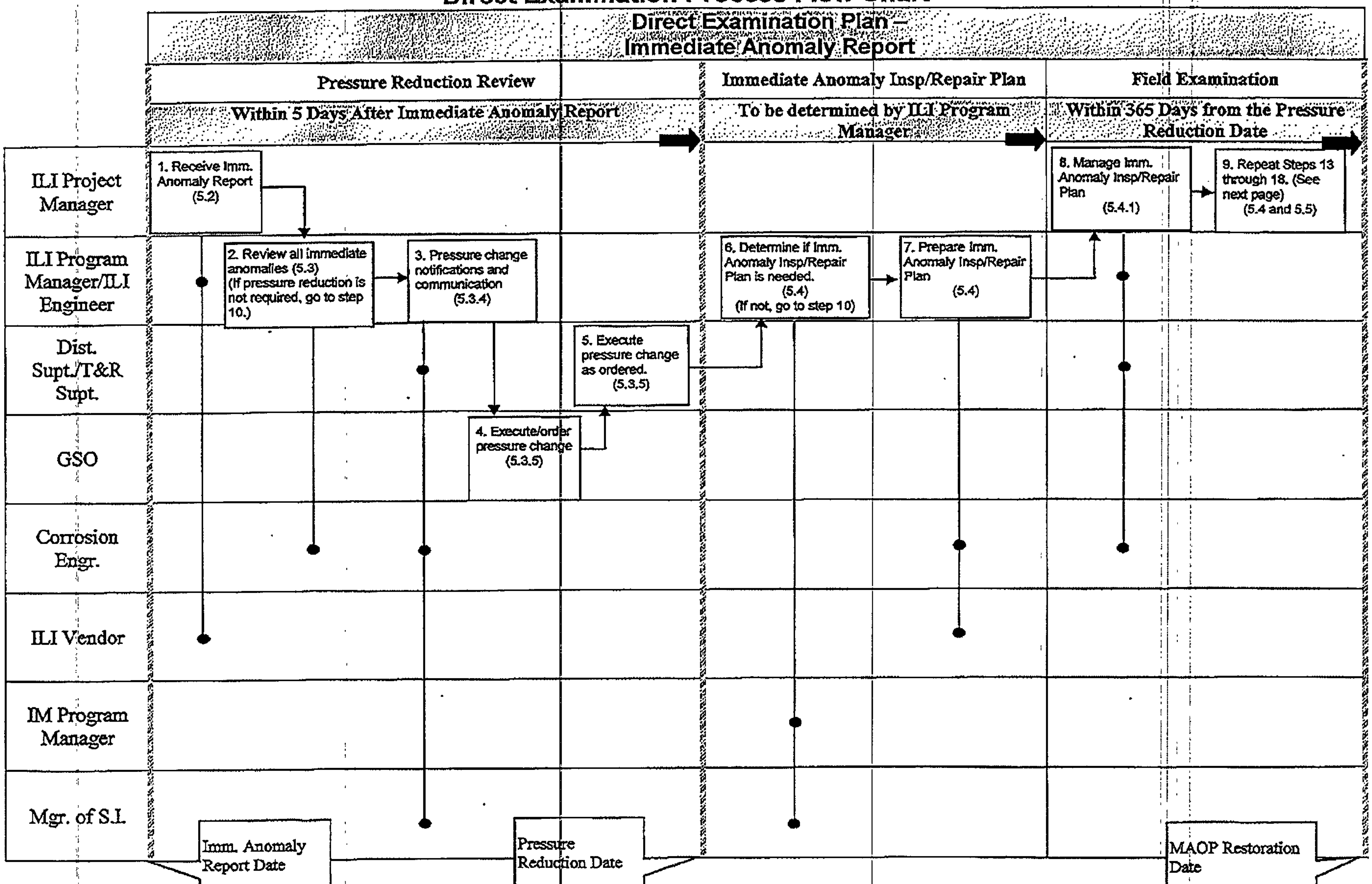
RMP-11

ATTACHMENT

Proprietary Information

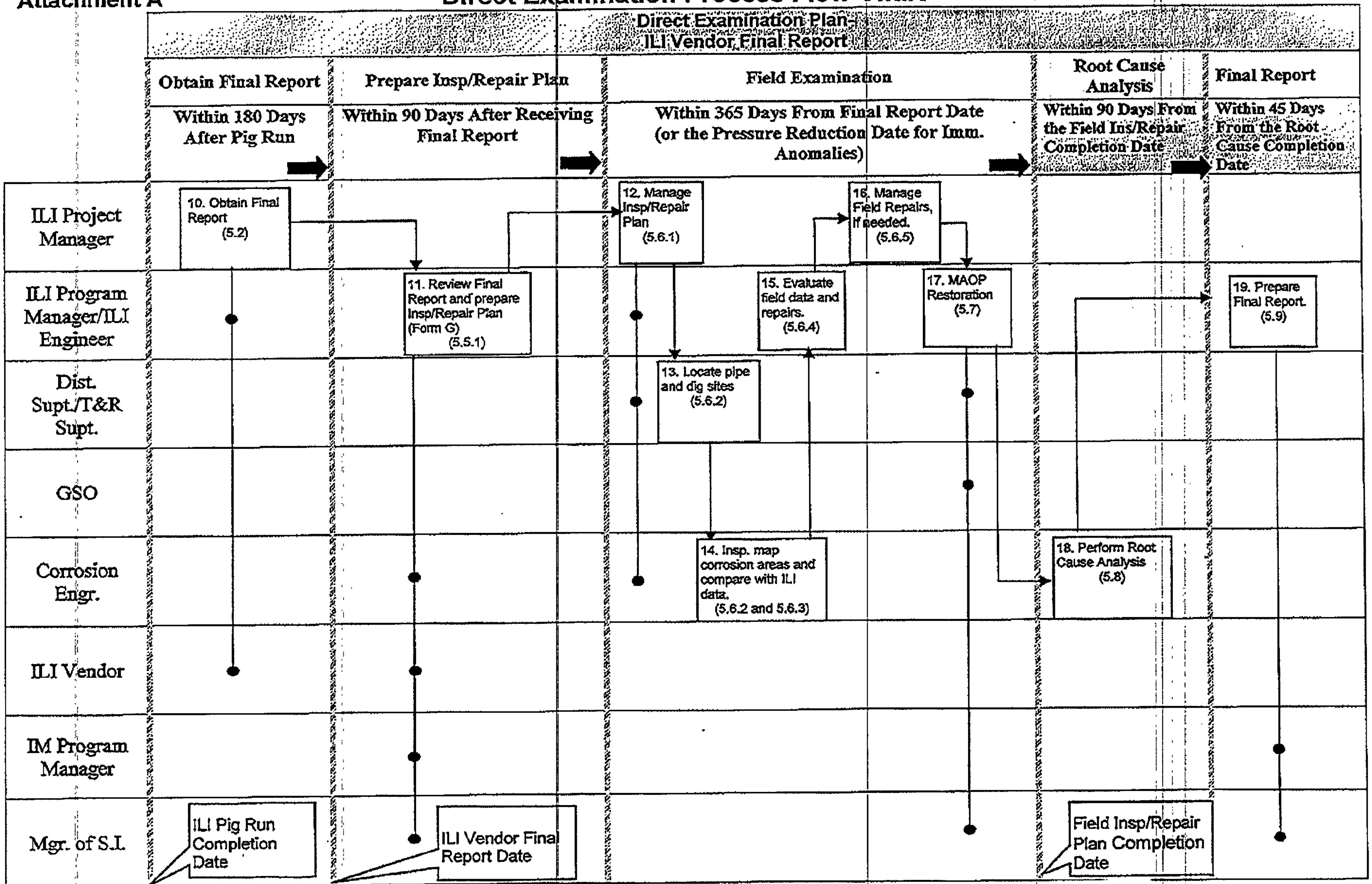
RMP-11
Attachment A

Direct Examination Process Flow Chart



RMP-11
Attachment A

Direct Examination Process Flow Chart



RMP-11

APPENDIX
[L] Forms

Proprietary Information

FORM A: DATA ELEMENT CHECK SHEET

LINE NUMBER: ____________
STARTING MILE POINT: ____________
ENDING MILE POINT: ____________

REFERENCE SECTION: TABLE 3.3.1
PROJECT MANAGER: ____________

Table 3.3.1: Pre-assessment Data List

Description				Requirements			Data Source					
ID #	Data Element Description	In-Line Inspection Tool Selection	Interpretation and Analysis Of Inspection Results	Need[1]	Inspection Tool[2]	Interpretation and Analysis of Inspection Results[2]	GIS	As-built Job file	Field	Districts or Division	Other	Comments
1.0 Pipe Related												
1.1	Diameter	May reduce detection capability or prohibit passage of tool	For performing RSTRENG	R	R	R	X	X			Pipeline Features List	
1.2	Wall Thickness	May reduce detection capability or prohibit passage of tool	Impacts critical anomaly size	R	R	R	X	X			Pipeline Features List	
1.3	Grade		For performing RSTRENG	R	N/R	R	X	X			Pipeline Features List	
1.4	Seam Type		Older pipe typically has lower weld seam toughness that reduces critical anomaly size. Pre-1970 ERW or flash welded pipe may be subject to higher corrosion rates than the base metal	D	N/R	C	X	X			Pipeline Features List	
1.5	Year Manufactured	May influence tool selection	Older pipe typically has lower weld seam toughness that reduces critical anomaly size. Pre-1970 ERW or flash welded pipe may be subject to higher corrosion rates than the base metal	D	N/R	C	X	X			Pipeline Features List	
2.0 Construction Related												
2.1	Year Installed		Impacts time over which coating degradation may occur, anomaly population estimates, and corrosion rate estimates	D	N/R	C	X	X			Pipeline Features List	
2.2	Recent route changes/ modifications that may not be in GIS			D	C	N/R		X	X	X		
2.3	Construction Practices		May indicate construction problems that may have occurred; e.g., BBCR, miter bends, wrinkle bends, etc.	D	C	C		X			Engr. Stds. drawings	
2.4	Location of major pipe appurtenances such as valves and taps	Investigate potential need for replacement or the installation of bars for tees.	Provides a 'known' reference for geo-referencing indications	R	R	C	X	X	X			

1 R = Required, D = Desired (See paragraph 2.5 for definitions)
2 R = Required, C = Considered; N/R = Not required

Description				Requirements			Data Source					
ID #	Data Element Description	In-Line Inspection Tool Selection	Interpretation and Analysis Of Inspection Results	Need[1]	Inspection Tool[1]	Interpretation and Analysis of Inspection Results[2]	GIS	As-built Job file	Field	Districts or Division	Other	Comments
2.5	Location of bends, including miter bends and wrinkle bends	May indicate locations at which replacements are needed to make the pipeline piggable	Provides a 'known' reference for geo-referencing indications	R	R	C		X			Trans. Plat Sheet	
2.6	Location of casings		Provides a 'known' reference for geo-referencing indications	D	N/R	C		X	X	X		
2.7	Proximity to other pipeline structures, HV electric transmission lines and rail crossings		Possible CP interference and 3rd party damage	D	C	C	X		X			
2.8	Underwater sections and river crossings		Access issue for post pigging dig and potential coating defect	C	N/R	C	X	X	X			
2.9	Location of bores		Access issue for post pigging dig and potential coating defect	D	N/R	C		X				
3.0 Soils/Environmental												
3.1	Soil characteristics & types		Can be useful in interpreting results. Influences corrosion rate	D	C	C	X		X		Form 4110	
3.2	Assessment of environmental conditions		May indicate potential environmentally sensitive areas	D	N/R	C	X		X			
3.3	Topography		Conditions such as rocky areas can make field inspections difficult or impossible.	D	C	N/R			X			
3.4	Land use (current/pass)		Can be considered in evaluating the potential severity of damage.	D	C	C	X		X			
3.5	Locations of poor drainage		Influences corrosion rate and remaining life calculation	D	N/R	C			X	X		
4.0 External Corrosion												
4.1	CP System Type (anodes, rectifiers, and locations)		Support root cause analysis and CIS survey	D	N/R	C			X	X	CPA Records	
4.2	CP system boundaries		Support root cause analysis and CIS survey	D	N/R	C			X	X	CPA Records	
4.3	Locations of Isolation Points		Support root cause analysis and CIS survey	D	N/R	C			X	X	CPA Records	
4.4	Locations of Connections to Distribution		Support root cause analysis and CIS survey	D	N/R	C			X	X	CPA Records	
4.5	Stray Current source/locations		Support root cause analysis and CIS survey	D	N/R	C			X	X	CPA Records, past survey reports.	

Description				Requirements			Data Source					
ID #	Data Element Description	In-Line Inspection Tool Selection	Interpretation and Analysis Of Inspection Results	Need[1]	Inspection Tool[2]	Interpretation and Analysis of Inspection Results[3]	GIS	As-built/Job file	Field	Districts or Division	Other	Comments
4.6	Test point locations (pipe access points)		May provide geographic reference for ILI run	D	N/R	C	X		X	X	CPA Records	
4.7	CP evaluation criteria		Used in post-assessment analysis	D	N/R	C					CPA Records, Paradigm	
4.8	CP maintenance history		Support root cause analysis and CIS survey	D	N/R	C				X	CPA Records, Paradigm	
4.9	Years without CP applied		Negatively effects ability to estimate corrosion rates	D	N/R	C		X		X		
4.10	Coating type - pipe		Coating type may influence time at which corrosion begins and estimates of corrosion rate based on measured wall loss.	D	N/R	C	X	X				
4.11	Coating condition		May help with root cause analysis of anomalies	D	N/R	C	X			X	Direct Assessment	
4.12	Current demand		Support root cause analysis and CIS survey	D	N/R	C				X	CPA Records	
4.13	CP survey data/history		Support root cause analysis and CIS survey	D	N/R	C					CPA Records Paradigm, Corrosion Group	
5.0 Operational Data												
5.1	Operating stress level, pressure, flow rate	For controlling the pigging velocity	Impacts critical anomaly size	R	R	R	X				GSO, TSP	
5.2	Monitoring programs (patrol leak surveys etc.)		May impact repair, remediation and replacement schedules.	D	N/R	C					Corrosion Group, Form 4110	
5.3	Pipe inspection reports-excavation		Provide useful data for post-assessment analysis or data verification	D	N/R	C	X			X	Form 4110	
5.4	Repair history/records, steel/composite repair sleeves, repair locations		Provide useful data for post-assessment analysis or data verification	D	N/R	C	X			X	Form 4110	
5.5	Leak/rupture history		Provide useful data for post-assessment analysis	D	N/R	C	X			X	Form 4110	
5.6	Type and frequency of third party damage (review construction activities with operating personnel)		High third party damage areas may have increased coating fault anomalies.	R	N/R	R	X		X	X	Form 4110 USA Data Base Patrol Records	
5.7	Other prior integrity related activities – CIS, ILI runs, etc.		Useful post-assessment data	R	N/R	R	X				Corrosion Group, System	

Description				Requirements			Data Source					
ID #	Data Element Description	In-Line Inspection Tool Selection	Interpretation and Analysis Of Inspection Results	Need?	Inspection Tool?	Interpretation and Analysis of Inspection Results?	GIS	As-built Job file	Field	Districts or Division	Other	Comments
											Integrity	
5.8	Hydro test dates/pressures		Affects manufacture threat review	D	N/R	C	X	X				
5.9	Known areas of shallow cover		Potential 3rd party damage	D	N/R	C			X	X		
5.10	Location of abnormal pipe operating temperatures		Possible locations for SCC, Influence of activating manufacture defects.	D	N/R	C					SCADA	
6.0 Internal Corrosion (IC)												
6.1	History of IC leaks		Influence post-pigging dig plan	D	C	C	X		X	X		
6.2	Received gas from gathering or storage lines		To establish threat for potential IC, influence post-pigging dig plan	D	N/R	D	X		X			
6.3	Drip location		Influence post-pigging dig plan	D	N/R	C	X		X			
6.4	Drip fluid analysis		Influence post-pigging dig plan	D	D	D	X		X	X		
6.5	Inhibitor injection		Influence post-pigging dig plan	D	D	D	X		X	X		
6.6	Previously "pigged"		Influence post-pigging dig plan	D	N/R	C				X		
6.7	Corrosion monitoring (LPR probes, weight loss coupons, corrosometer probes, etc.)		Influence Root Cause analysis, post-pigging dig plan, and the LTIMP prevention and mitigation plan.	D	N/R	C				X	Maintenance Records	
7.0 Hard Spot												
7.1	Year installed, mill, seam type, etc. per RMP-06 Section 3.5	Will affect tool selection	Influence Root Cause analysis, post-pigging dig plan, and the LTIMP prevention and mitigation plan	D	C	C	X	X				
7.2	Records of hard spot failures	Will affect tool selection	Influence Root Cause analysis, post-pigging dig plan, and the LTIMP prevention and mitigation plan	D	C	C	X				Form 4110	
7.3	Abnormal CP levels		Influence Root Cause analysis, post-pigging dig plan, and the LTIMP prevention and mitigation plan	D	C	C	X			X		

ILI Engineer: ______________________ Date: ______________

Proprietary Information

Form B: Sufficient Data Analysis Form

LINE NUMBER:________________

STARTING MILE POINT:________________

ENDING MILE POINT:________________

REFERENCE: SECTION 3.7

PROJECT MANAGER:________________

SUFFICIENT DATA ANALYSIS

Missing Required Data Elements				
ID#	Data Element Description	Pipe Segments	Reason for missing data	Explanation why it is not needed (if any)

Sufficient Data: Yes____ No____ **ILI Engineer:** ________________ **Date:** ________________

Proprietary Information

Form C: Feasibility Analysis Form

LINE NUMBER: ____________________
STARTING MILE POINT: ____________
ENDING MILE POINT: ______________

REFERENCE SECTION: SECTIONS 3.8
PROJECT MANAGER: ____________________

Instructions: Analyze each data and note any of the issues listed below. In answering the question include the following:

1) Any adverse conditions that may make the pipe segments infeasible to ILI. Refer to Table 3.3.1 for guidance.
2) Any special considerations, techniques that need to be incorporated or considered in conducting the ILI to over come the adverse conditions
3) A conclusion on the feasibility of conducting an ILI for all the pipe segments in the ILI project

ILI FEASIBILITY ANALYSIS

ID #	Data Categories	In-Line Inspection Can existing In-Line Inspection tools be applied to the pipe segments identified in the ILI project and be expected to provide meaningful results on potential locations where the pipe wall is damaged?	Direct Examination Is it physically and economically feasible to gain access to the pipeline to conduct direct examination and be expected to gain meaningful data?
1.0	Pipe Related		
2.0	Construction Related		
3.0	Soils/Environmental		
4.0	Corrosion Control		
5.0	Operational Data		

ILI Feasible: Yes____ No____

ILI Engineer: ____________________ **Date:** ____________________

ILI Program Manager: ____________________ **Date:** ____________________

NOTE: Signing this form confirms authorization of forms A-C.

Form D: Above Ground Marker Locations

Reference Section: Section 4.2

Line Number: ____________________
Starting Mile Point: ____________________
Ending Mile Point: ____________________

Project Manager: ____________________

Above Ground Marker #	Mile Point (From GIS)	Above Ground Distance Between AGMs (feet)	Easting (UTM NAD83) (meters)	Northing (UTM NAD83) (meters)	Ground Elevation (UTM NAD83) (feet)	Depth of Cover[1] (feet)	Type of AGM[2]	Type of Marker[3]	Comments

ILI Engineer: ____________________ **Date:** ____________________

(1) To top of pipe
(2) Examples include - Point on line, major pipe appurtenances
(3) Examples include - Concrete, iron pipe, rebar, nail and shine, etc.

Form E: ILI Vendor Qualification Form

REFERENCE: SECTION 4.3

ILIT METHOD[1]: ____________________

VENDOR NAME: ____________________

INSTRUCTIONS: Paragraph 4.3.1.2 in the ILI Procedure provides instructions on completing and filing of this form.

Specification Content Review

Acceptable	Not Acceptable		Comments
☐	☐	Safety	
☐	☐	Sizing Accuracy	
☐	☐	Caliper Accuracy	
☐	☐	Geospatial Accuracy	
☐	☐	Operator Qualifications	
☐	☐	Schedule	
☐	☐	Report Format	

General Comments/Exceptions: ____________________

Approved	Not Approved	
☐	☐	**Comment:** ____________________

ILI Engineer: ____________________ **Date:** ____________

ILI Program Manager: ____________________ **Date:** ____________

(1) MFL, TFI, EMAT, etc.

Proprietary Information

Form F: Immediate Anomalies Analysis
(To be completed when Immediate Anomalies are received.)

Line Number: ______________________
Starting Mile Point: ______________________
Ending Mile Point: ______________________

Reference Section: Sections 5.3, 5.4
ILI Run Date: ______________________
PG&E Notification Date[1]: ______________________
Project Manager: ______________________

ILI Data											Assessment									
MP	ILI Log Distance	Type of Indication(2)	% Thru Wall	% Dent	Length	O'clock Position	Pf/MAOP (ILI Report)	O.D.	W.T.	Grade	Class Location	HCA? (Y/N)	Pf	MAOP	Ps	Pf/MAOP	Priority(3)	Pdis(4)	80% of Pdis	Comments

Per the evaluation above, the safe operating pressure is: ______________________
GSO Notification Date: ______________________
Pressure Reduction Date: ______________________
Safety Related Condition? (Y/N): ______________________ **If Yes, Notification Date:** ______________________

ILI Engineer: ______________________ **Date:** ______________________

ILI Program Manager: ______________________ **Date:** ______________________

(1) The date the ILI vender notifies PG&E of an immediate anomaly.
(2) Metal loss-external, metal loss-internal, dents, etc.
(3) See Table 5.5.1
(4) Pdis equals the highest pressure during the ILIT run or the maximum pressure between the ILIT run and the time the immediate anomalies are identified.

Proprietary Information

Form G: Anomaly Prioritization and Direct Examination Form (Inspection/Repair Plan)
(To be used for excavations using ILI data.)

Line Number: ____________________
Starting Mile Point: ____________________
Ending Mile Point: ____________________

Reference Section: Sections 5.4, 5.5
ILI Vendor Final Report Date: ____________________
ILI Run Date: ____________________
Project Manager: ____________________

ILI Report												Assessment								
Dig Site #	MP	ILI Log Distance	Type of Indication(1)	% Thru Wall	% Dent	Length	O'clock Position	Pf/MAOP (ILI Report)	O.D.	W.T.	Grade	Class Location	HCA? (Y/N)	Pf	MAOP	Pf/MAOP	Pipeline % SMYS at MAOP	Priority(2)	Dig (Y/N)	Comments

ILI Engineer: ____________________ **Date:** ____________________

ILI Program Manager: ____________________ **Date:** ____________________

Manager of Technical Services: ____________________ **Date:** ____________________

(1) Metal loss-external, metal loss-internal, dents, etc.
(2) See table 5.5.1

Form H: Direct Examination Data Sheet - Page 1 of 10

DA/ILI

Route Number:
Examination Date:
Mile Point:
Examination Performed By:
PG&E Project Manager:
Approved By:
Order Number:

DA

N-Segment:
IMA Number:

Region Number:
Subregion # (ICDA):
Stationing:

ILI

ILI Log Distance:
RMP-11 Ref. Section: Table 5.6.2
Reference Girth Weld:
Distance From Girth Weld:

Excavation Priority:

☐ Immediate ☐ Scheduled (For ILI - Effectiveness ☐ 1 Year ☐ Other)
☐ Monitor ☐ ICDA

Excavation Reason

☐ ECDA ☐ ILI ☐ Recoat
☐ ICDA ☐ Other

If practical, take P/S or CIS reads before excavation:

Excavation Details: Centerline on GPS Coordinates (Based on GIS):
Northing:
Easting:

Planned Excavation Length (Ft.):
Actual Excavation Length (Ft.):

Centerline on GPS Coordinates (Uncorrected Field Measurement):
Northing:
Easting:

GPS File Name:

Centerline on GPS Coordinates (Corrected Field Measurement):
Northing:
Easting:

1.0 Data Before Coating Removal

1.1 Native Soil Type: ☐ Clay ☐ Rock ☐ Sand ☐ Loam ☐ Wet ☐ Other

1.1a Backfill Material Found ☐ Sand ☐ Slurry ☐ Native

Depth of Cover (Ft.):

Comments:

1.2 Coating Type: ☐ HAA ☐ Somastic ☐ Plastic Tape ☐ Wax Tape ☐ FBE ☐ Powercrete
☐ Bare/None ☐ Paint ☐ Other: Comments:

Coating Thickness (inches): Number of Layers:

1.3 Holiday Testing Performed?: ☐ Yes ☐ No Voltage Used: Map Location of Holidays Below.
Device Used: ☐ Coil ☐ Wet Sponge Comments:

1.4 Pipe-to-Soil Potentials in Ditch (-mV): US: DS:
Comments:

1.5 Soil Resistivity in Ditch (Ω-cm):
Method: ☐ 4-Pin ☐ Soil Box

1.6 Soil Sample Location: Comments:

1.7 Ground Water Present?: ☐ Yes ☐ No Sample(s) Collected?: ☐ Yes ☐ No Sample pH:
Comments:

1.8 Coating Condition: ☐ Good - Adhered to Pipe ☐ Fair - Coating Partially Disbonded or Degraded
☐ Poor - Coating Significantly Disbonded or Missing

Comments:

1.9 Map of Coating Degradation*: Zero Reference Point:
*Note any calcareous deposit locations

Flow →

12 o'clock										
9 o'clock										
6 o'clock										
3 o'clock										
12 o'clock										

Form H: Direct Examination Data Sheet - Page 2 of 10

DA/ILI		DA		ILI	
Route Number:		N-Segment:		ILI Log Distance:	
Examination Date:		IMA Number:		RMP-11 Ref. Section:	Table 5.6.2
Mile Point:				Reference Girth Weld:	
Examination Performed By:		Region Number:		Distance From Girth Weld:	
PG&E Project Manager:		Subregion # (ICDA):			
Approved By:		Stationing:			
Order Number:					

1.10 Photos Taken?*: ☐ Yes ☐ No
*See Photo Log for additional information.

1.11 Coating Sample Taken?: ☐ Yes ☐ No Location of Sample: ____

1.12 Liquid Underneath Coating?: ☐ Yes ☐ No If Yes, pH of Liquid: ____

1.13 Corrosion Product Present?: ☐ Yes ☐ No If Yes, Was Sample Taken?: ☐ Yes ☐ No
Comments: ____

1.14 Soil pH (Sb Electrode): Upstream: ____ Downstream: ____

2.0 Data After Coating Removal

2.1 Pipe Temperature (°F): ____ Measured Pipe Diameter (in.): ____

2.2 Weld Seam Type: ☐ DSAW ☐ SSAW ☐ ERW ☐ SMLS
☐ Spiral ☐ Lap ☐ Flash ☐ AO Smith ☐ If can't determine, visually perform macroetch to locate & identify type (see Table 5.7.3, Element 2.2)

2.3 Girth Weld Coordinates:
Northing: ____
Easting: ____
Elevation: ____
Weld Clock Position: ____

2.4 Damage Found:
Corrosion Damage ☐ Yes ☐ No Mechanical Damage ☐ Yes ☐ No
Other Damage: ____

2.5 UT Wall Thickness Measurements: TDC: ____ 1 O'clock: ____ 2 O'clock: ____ 3 O'clock: ____
4 O'clock: ____ 5 O'clock: ____ 6 O'clock: ____ 7 O'clock: ____
8 O'clock: ____ 9 O'clock: ____ 10 O'clock: ____ 11 O'clock: ____

UT Wall Thickness Grid @ 6:00 is required. Be sure to attach grid to H-Form electronically. See page 6 of 10.

2.6 Wet Fluorescent Mag. Part. is Required. Comments: ____
Were there any linear indications? ☐ Yes ☐ No If Yes, attach NDE report electronically as part of the H-Form. Report to include black light and white light photos of indications.

2.7 Take Photos to Document Corrosion and Other Anomalies*
*See Photo Log for additional information.

2.8 Overview Map of Corroded Area*:
*See Pit Depth Measurement Grid for additional information
*Note any calcareous deposits.
Zero Reference Point: ____

Flow →

12 o'clock	1	7	13	19	25	31	37	43	49	55
	2	8	14	20	26	32	38	44	50	56
9 o'clock	3	9	15	21	27	33	39	45	51	57
6 o'clock	4	10	16	22	28	34	40	46	52	58
	5	11	17	23	29	35	41	47	53	59
3 o'clock	6	12	18	24	30	36	42	48	54	60
12 o'clock										
Feet	0	1	2	3	4	5	6	7	8	9 10

Form H: Direct Examination Data Sheet - Page 3 of 10

DA/ILI

Route Number: ____________
Examination Date: ____________
Mile Point: ____________
Examination Performed By: ____________
PG&E Project Manager: ____________
Approved By: ____________
Order Number: ____________

DA

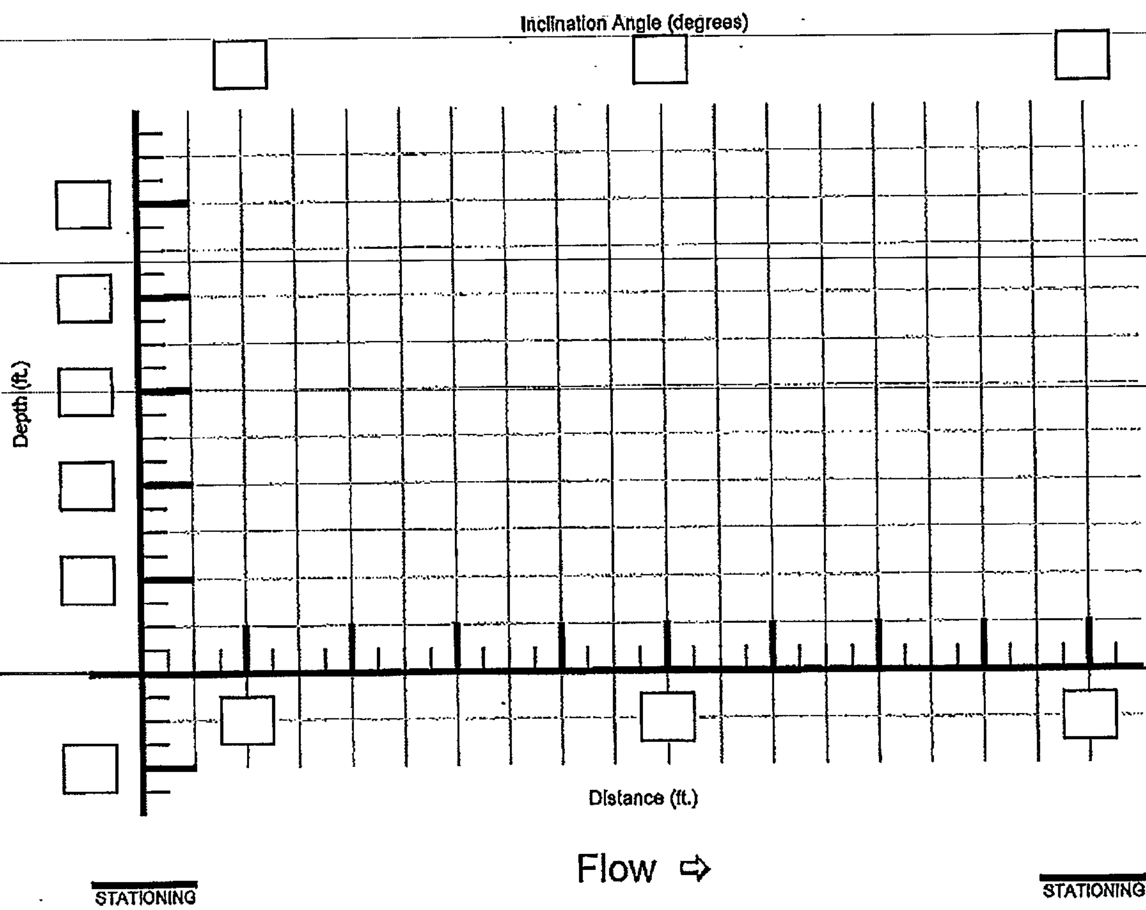
N-Segment: ____________
IMA Number: ____________
____
Region Number: ____________
Subregion # (ICDA): ____________
Stationing: ____________

ILI

ILI Log Distance: ____________
RMP-11 Ref. Section: Table 5.6.2
Reference Girth Weld: ____________
Distance From Girth Weld: ____________

Excavation Drawing:

At minimum draw pipe elevation profile and indicate stationing of 1) low point and 2) critical inclination angle.
Place an arrow on the drawing indicating direction of gas flow in the region(s). Other labels may also be added (e.g. "to Station").



NOTES: (Record stationing and names of nearby landmarks such as creeks and roads. Provide any additional information that may help in spatially positioning pipe):

____
____
____

Form H: Direct Examination Data Sheet - Page 4 of 10

EXTERNAL PIT DEPTH MEASUREMENT GRID SHEETS

DA/ILI

Route Number: ______

Examination Date: ______

Mile Point: ______

Examination Performed By: ______

PG&E Project Manager: ______

Approved By: ______

Order Number: ______

DA

N-Segment: ______

IMA Number: ______

______

Region Number: ______

Subregion # (ICDA): ______

Stationing: ______

ILI

ILI Log Distance: ______

RMP-11 Ref. Section: Table 5.6.2

Reference Girth Weld: ______

Distance From Girth Weld: ______

Grid Size = _____ inch x _____ inch (specify grid size)

Clock Position (specify below)

Anomaly # : ______ Grid #: ______

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
A																						
B																						
C																						
D																						
E																						
F																						
G																						
H																						
I																						
J																						
K																						
L																						
M																						
N																						
O																						
P																						
Q																						
R																						
S																						
T																						
U																						
V																						
W																						
X																						

PIT DEPTH GRID 1 OF 2

Form H: Direct Examination Data Sheet - Page 6 of 10

EXTERNAL PIT DEPTH MEASUREMENT GRID SHEETS

DA/ILI		DA		ILI	
Route Number:		N-Segment:		ILI Log Distance:	
Examination Date:		IMA Number:		RMP-11 Ref. Section:	Table 5.6.2
Mile Point:				Reference Girth Weld:	
Examination Performed By:		Region Number:		Distance From Girth Weld:	
PG&E Project Manager:		Subregion # (ICDA):			
Approved By:		Stationing:			
Order Number:					

Grid Size = ______ inch x ______ inch (specify grid size)

Clock Position (specify below)

Anomaly #: ______________________ Grid #: ______________________

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
A																						
B																						
C																						
D																						
E																						
F																						
G																						
H																						
I																						
J																						
K																						
L																						
M																						
N																						
O																						
P																						
Q																						
R																						
S																						
T																						
U																						
V																						
W																						
X																						

PIT DEPTH GRID 2 OF 2

Form H: Direct Examination Data Sheet - Page 6 of 10

INTERNAL CORROSION PIT DEPTH GRID

DA/ILI		DA		ILI	
Route Number:		N-Segment:		ILI Log Distance:	
Examination Date:		IMA Number:		RMP-11 Ref. Section:	Table 6.6.2
Mile Point:				Reference Girth Weld:	
Examination Performed By:		Region Number:		Distance From Girth Weld:	
PG&E Project Manager:		Subregion # (ICDA):			
Approved By:		Stationing:			
Order Number:					

Grid Size = 1 inch x 1 inch

Clock Position (specify below)

	1	2	3	4	5	6	7	8	9	10	11	12
A												
B												
C												
D												
E												
F												
G												
H												
I												
J												
K												
L												

INTERNAL CORROSION GRID

1 of 1

Form H: Direct Examination Data Sheet - Page 7 of 10

COATING DAMAGE

DA/ILI

Route Number: ________
Examination Date: ________
Mile Point: ________
Examination Performed By: ________
PG&E Project Manager: ________
Approved By: ________
Order Number: ________

DA

N-Segment: ________
IMA Number: ________
Region Number: ________
Subregion # (ICDA): ________
Stationing: ________

ILI

ILI Log Distance: ________
RMP-11 Ref. Section: Table 5.6.2
Reference Girth Weld: ________
Distance From Girth Weld: ________

NO.	FEET FROM REFERENCE	O'CLOCK	MAX LENGTH (IN.)	MAX CIRC EXTENT (IN.)

Form H: Direct Examination Data Sheet - Page 8 of 10

CORROSION LOG

DA/ILI		DA		ILI	
Route Number:		N-Segment:		ILI Log Distance:	
Examination Date:		IMA Number:		RMP-11 Ref. Section:	Table 5.6.2
Mile Point:				Reference Girth Weld:	
Examination Performed By:		Region Number:		Distance From Girth Weld:	
PG&E Project Manager:		Subregion # (ICDA):			
Approved By:		Stationing:			
Order Number:					

IC or EC	FEET FROM REFERENCE	O'CLOCK	MAX PIT DEPTH (MILS)	MAX LENGTH (IN.)	MAX CIRC EXTENT (IN.)

PHOTO LOG

DA/ILI
Route Number: ____________
Examination Date: ____________
Mile Point: ____________
Examination Performed By: ____________
PG&E Project Manager: ____________
Approved By: ____________
Order Number: ____________

DA
N-Segment: ____________
IMA Number: ____________
____
Region Number: ____________
Subregion # (ICDA): ____________
Stationing: ____________

ILI
ILI Log Distance: ____________
RMP-11 Ref. Section: Table 5.6.2
Reference Girth Weld: ____________
Distance From Girth Weld: ____________

PHOTO NO.	LOCATION	DESCRIPTION	COMMENTS

Form H: Direct Examination Data Sheet - Page 10 of 10

DA/ILI		DA		ILI	
Route Number:		N-Segment:		ILI Log Distance:	
Examination Date:		IMA Number:		RMP-11 Ref. Section:	Table 5.6.2
Mile Point:				Reference Girth Weld:	
Examination Performed By:		Region Number:		Distance From Girth Weld:	
PG&E Project Manager:		Subregion # (ICDA):			
Approved By:		Stationing:			
Order Number:					

3.0 Recoat Data

3.1 Sandblast Media: ______ Anchor Profile Measurement: ______

3.2 Pipe Recoated With:

☐ Powercrete J ☐ Wax Tape ☐ Bar-Rust 235 ☐ Dev Grip 238 ☐ Dev Tar 247 ☐ Protal 7200 ☐ PE Tape

3.3 For Epoxy Coating Systems, Record Environmental Condition:

Air Temperature: ______ Dew Point: ______
Pipe Temperature: ______ Relative Humidity: ______
Time of Day: ______

3.4 Repair Coating Hardness (if ARC Coating:) ______

3.5 Measured Coating Thickness: 3:00 - ______ 6:00 - ______ 9:00 - ______ 12:00 - ______

Holiday Tested?: ☐ Yes ☐ No

Device Used: ☐ Coil ☐ Wet Sponge Voltage Used: ______ Repair All Holidays.

3.6 Coupon Test Station Installed?: ☐ Yes ☐ No ETS Installed?: ☐ Yes ☐ No

If Yes, Date Installed: ______

Surface Configuration:: ☐ Fink ☐ G-5 Box ☐ Carsonite ☐ Other: ______

3.7 Backfill Material: ☐ Native ☐ Imported Sand ☐ Other: ______

Coating Protections?: ☐ Yes ☐ No

If Yes, Check One: ☐ Rockguard ☐ Tuf-E-Nuf ☐ Conwed ☐ Other: ______

3.8 Pipe-to-Soil Readings Over Bell Hole After Backfill: ______

*If specified, a CIS should be done for approximately 100' on either side of the bell hole. Attach data.

Comments: ______

3.9 Attach site sketch of excavation site.

4.0 Repair Data

4.1 Repair Made: ☐ Yes ☐ No 4.1 Number of repairs made: ______

4.3 Repair Type: ☐ Metallic Sleeve ☐ Non Metallic Sleeve ☐ Replace ☐ Can ☐ Filler Metal ☐ Other

4.4 Damage Repaired: ☐ Corrosion ☐ Mechanical ☐ Other

Misc. Comments/Information: ______

Form I: Field Examination RSTRENG Summary

Reference Section: Section 5.6

Line Number: ____________________
Starting Mile Point: ____________________
Ending Mile Point: ____________________

ILI Vendor Final Report Date: ____________________
Project Manager: ____________________

ILI Report (From Form G)								Effective Area Calculation Based on Field Data											Repair Information		
MP	ILI Log Distance	Type of Indication(1)	% Thru Wall	% Dent	Length	O'clock Position	Priority	% Thru Wall	% Dent	Length	O'clock Position	MAOP	Pipeline % SMYS at MAOP	Pf(2)	Pf/MAOP	New Priority	Engineer	Date	Repair Required (Y/N)	Repair Date	Comments - Type of Repair

ILI Engineer: ____________________ Date: ____________

ILI Program Manager: ____________________ Date: ____________

(1) Metal loss-external, metal loss-internal, dents, etc.
(2) Pf = highest burst pressure calculated from RSTRENG

RMP-11

<u>Form J</u>: (Left Blank Intentionally)

Form K (1 of 2): ILI Root Cause Analysis Report

LINE NUMBER: ____________________ ILI LOG DISTANCE: ____________________
DATE OF EXCAVATION: ____________________ RMP-11 REF. SECTION: 5.8
MILE POINT: ____________________ DIG SITES: ____________________
EXAMINATION PERFORMED BY: ____________________
PROJECT MANAGER: ____________________
APPROVED BY: ____________________

Description and Extent of Damage:
☐ Coating Damage ☐ Pitting ☐ Gen. Wall Loss ☐ Dent ☐ Gouge ☐ Other ____________________

Rocks in Coating: ☐ Yes ☐ No **Evidence of Shielding:** ☐ Yes ☐ No

Coating Type: ☐ HAA ☐ Somastic ☐ Plastic Tape ☐ Wax Tape ☐ FBE ☐ Other-Epoxy ☐ Bare/None
☐ Paint ☐ Other ____________________ Comments: ____________________

Extent of Coating Degradation: ____________________

Max. Depth of Corr.: ____________________ **Max Length of Corr.:** ____________________
Comments: ____________________

Matrix of Testing Performed:
Soil Resistivity: ☐ Yes ☐ No Result: ____________________
Lab Soils Protocol: ☐ Yes ☐ No Results: ____________________
MIC Testing Performed: ☐ Yes ☐ No Results [Log (counts/ml)]: SRB ____ APB ____ AERO ____ ANA ____
pH of Water Under Coating: ____________________ CIS Over Bell Hole: ☐ Yes ☐ No
CIS Result: ____________________ P/S Spot Reads in Trench: ☐ Yes ☐ No Result: ____________________
Additional Testing: ____________________

Comments: ____________________

Review of CP Maintenance History:
Summary Review of Compliance Reads: ____________________

IIT Results Before Excavation: ____________________

CIS or P/S Results or P/S After Burial: ____________________

Other Information: ____________________

Review of Existing Damage Mitigation Measures:

Form K (2 of 2): ILI Root Cause Analysis Report

LINE NUMBER:		ILI LOG DISTANCE:	
DATE OF EXCAVATION:		RMP-11 REF. SECTION:	5.8
MILE POINT:		DIG SITES:	
EXAMINATION PERFORMED BY:			
PROJECT MANAGER:			
APPROVED BY:			

Analysis of Data for Root Cause:

Root Cause of Damage:

Additional Testing, Mitigation and/or Analysis Needed For Long-Term Pipeline Integrity:

Lessons Learned:

Incorporate Into Procedure? ☐ Yes ☐ No Date:

Incorporate Immediately to Future Root Cause? ☐ Yes ☐ No Date:

Recommended Items:

Senior Corrosion Engineer: ______________________ Date: ______________

Approved: ______________________ Date: ______________

Manager, Technical Services

RMP-11

<u>Form L:</u> (Left Blank Intentionally)

Proprietary Information

Form M: Exception Report

Line Number: ____________________

REFERENCE: ____ SECTIONS 7.0

DATE OF EXCEPTION REPORT: ____________________
IMA NUMBER: ____________________
PROJECT MANAGER: ____________________

Paragraph Number of Exception: ____________

Requirements of Paragraph (Your own words): ____________________

Alternative Plan: ____________________

Reason for Exception: ____________________

Recommendation: Should the procedure be changed? YES ____ NO ____
Comments: ____________________

CPUC Reportable? YES ____ NO ____

Will this change jeopardize public safety? YES ____ No ____
Justification: ____________________

ILI Engineer: ____________________ **Date:** ____________

ILI Program Manager: ____________________ **Date:** ____________

Manager of Technical Services: ____________________ **Date:** ____________

PACIFIC GAS AND ELECTRIC COMPANY

CALIFORNIA GAS TRANSMISSION
GAS SYSTEM MAINTENANCE & TECHNICAL SUPPORT
SYSTEM INTEGRITY SECTION
Risk Management

Procedure for Stress Corrosion Cracking Direct Assessment

Procedure No. RMP-13

Integrity Management Program

Prepared By: ____________ Date: 12-13-06
Robert Fassett, Direct Assessment Program Manager

Approved By: ____________ Date: 1/2/07
Chris Warner , Manager, System Integrity

1.0 PURPOSE

This document provides guidance on how to identify and classify the potential threat of SCC to pipeline integrity. The procedure is based on 49 CFR Part 192 "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)", specifically part 192.917 and ASME B31.8S A3 "Stress Corrosion Cracking Threat" and the NACE Recommended Practice RP0204-2004 on "Stress Corrosion Cracking (SCC) Direct Assessment Methodology". It is PG&E's policy to be in compliance with this practice as well as governing regulations and laws.

2.0 INTRODUCTION

"Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe/piping segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment."[1]

This plan provides a methodology for implementing an SCCDA program. It includes procedures and protocols written to:

- Ensure consistent and technically sound applications of SCCDA on buried pipeline segments,
- Comply with Title 49 Code of Federal Regulations Part 192 (CFR192) Subpart O. Paragraph 192.929.
- Address the Office of Pipeline Safety's Inspection Protocol for Gas Pipeline Integrity Management,
- Provide individual procedures for data collection, pre assessments, indirect inspections, excavations, and post assessments such that a pipeline company's SCCDA program can be audited per the OPS Inspection Protocol for SCCDA, and
- Improve pipeline safety and prevent the future impact of SCC on pipeline integrity.

This plan provides guidelines and examples to use in implementing SCCDA. It is applicable to buried onshore natural gas transmission and distribution line pipe constructed from steel. It is applicable to both forms of external SCC (near-neutral ph SCC and high ph SCC) Users of this plan are assumed to be familiar with applicable pipeline safety regulations and the NACE Standard Recommended Practice RP0204-2004 on SCC Direct Assessment.

2.1 Scope

This plan provides guidance in identifying and classifying the potential threat of SCC to pipeline integrity along with measures for monitoring and mitigation of pipe segments where SCC is found. The plan is based on 49 CFR Part 192 "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)", specifically part 192.917, ASME B31.8S A3 "Stress Corrosion Cracking Threat", and NACE Standard Recommended Practice RP02040-2004 "Stress Corrosion Cracking (SCC) Direct Assessment Methodology."

SCCDA is a continuous improvement process. Through successive applications, SCCDA is intended to identify and address locations where SCC has occurred, is occurring, or may occur.

SCCDA requires that an operator collect and integrate extensive data on its pipeline system. Indirect Inspections (aboveground surveys) may be used but are not required. Direct examinations are used to look for SCC. If SCC is found, mitigation, repair, and remediation are required.

---

[1] Title 49 Code of Federal Regulations Part 192 (CFR192) Subpart O.

2.2 SCCDA Overview

Direct assessment as per CFR 192.925 and the NACE Standard Recommended Practice RP02040-2004 "SCC Direct Assessment Methodology", is a four-step process for improving pipeline safety. These steps are:

- Pre-Assessment – A compilation of historic and current data to determine whether SCCDA is feasible and to prioritize the segments within a pipeline system with respect to potential susceptibility to SCC. The Pre-Assessment step also identifies specific sites within those segments for direct examinations. The types of data to be collected are typically available from in-house construction records, operating and maintenance histories, alignment sheets, corrosion survey records, other aboveground inspection records, government sources, and inspection reports from prior integrity evaluations or maintenance actions.
- Indirect Inspections – A compilation of additional data that are collected, as deemed necessary by the pipeline operator, to aid prioritization of segments and site selection for direct examination. The need to conduct indirect inspections and the nature of these inspections depends on the nature and extent of the data obtained in the pre-assessment step and the data requirements for site selection. Typical data collected in this step might include close-interval survey (CIS) data, direct-current voltage gradient (DCVG) data, and information on geotechnical conditions (soil type, topography, and drainage) along the right of way.
- Direct Examination – Includes procedures (1) to field verify the sites selected in the first two steps, and (2) to conduct the field digs. Aboveground measurements and inspections are performed to field verify the factors used to select the dig sites. For example, the presence and severity of coating faults might be confirmed. If predictive models based on geotechnical conditions are used, the topography, drainage, and soil type require verification so that they can be related to SCC susceptibility. The digs are then performed; the severity, extent, and type of SCC, if any is detected, at the individual dig sites are assessed; and data that can be used in post assessment and predictive-model development are collected.
- Post Assessment – Includes the analysis of data collected from the previous three steps to determine whether SCC mitigation is required, and if so, to prioritize those actions; to define the interval to the next full integrity reassessment; and to evaluate the overall effectiveness of the SCCDA approach.

Feedback within and between the four steps is important and required. Findings that are consistent with expectations strengthen the process. Inconsistent findings must be evaluated to determine why and how the process application should be changed, or whether SCCDA is not feasible. The inability to correlate historical data, indirect inspection data and predictive modeling to known indications of SCC may indicate that SCCDA is not feasible.

When SCCDA is applied for the first time on a pipeline segment, more stringent requirements apply. When the plan is applied to a pipeline segment that does not have a well-documented history of operations, maintenance, and cathodic protection conditions, additional requirements may also apply.

2.3 Roles and Responsibilities

2.3.1 Manager of System Integrity: The Manager of System Integrity has the overall responsibility to assure that this procedure is implemented effectively. This procedure assigns approval of documents, plans and exceptions to this position. The Manager of System Integrity may delegate some or all of these approving responsibilities.

2.3.2 **SCCDA Project Manager:** The SCCDA Project Manager (PM) is responsible to assure that all aspects of the assigned SCCDA projects are conducted in full compliance with this procedure. In addition, the PM is responsible for the effective planning, documenting and communicating the various aspects and stages of the assigned SCCDA projects.

2.3.3 **SCCDA Project Engineer:** The Project Engineer is responsible for the technical evaluations and analyses conducted through out the assessment process. These include, but are not limited to, sufficient data analysis, SCCDA Region Designation, Indirect Inspection results, and remaining strength evaluations.

2.3.4 **Inspection Personnel:** The Inspection Personnel (IP) are responsible for the assigned tasks corresponding to the SCC Detail Examinations. They are responsible for conducting the inspections and tests in accordance with this procedure and other testing procedures that have been referenced in the assessment process.

2.3.5 **Subject Matter Expert:** Subject matter experts are individuals that have expertise in a specific area of operation or engineering. The Subject Matter Expert could also be a 3rd Party Contractor that may fill any or all of the roles listed above, and would assume the responsibilities of that position.

2.3.6 **Direct Assessment Program Manager:** Reports to the Manager of System Integrity and is responsible for the supervision of the DA team and the management of all DA programs (ECDA, ICDA, SCCDA, CDA and Risk Management based DA projects)

2.4 Qualifications

The SCCDA assessment is to be implemented under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and related practical experience, are qualified to engage in the practice of corrosion control and risk assessment on ferrous piping systems.

The process for achievement of competency, awareness and training of personnel in the subject area they perform within the SCC process shall be documented.

The specific qualifications are described below.

Manager of System Integrity: The Manager of System Integrity shall be a degreed engineer and have gas transmission corrosion related experience to provide guidance and oversight to the personnel conducting the SCCDA process.

SCCDA Project Manager: The PM shall be a degreed engineer (or have equivalent pipeline experience and DA program Manager approval) and have sufficient gas transmission corrosion related experience to provide guidance and oversight to the personnel conducting the SCC process.

SCCDA Project Engineer: The PE shall be a degreed engineer with corrosion control experience in the pipeline industry, or a NACE certified Corrosion Specialist The engineer shall have been formally trained on this procedure.

Inspection Personnel: The personnel performing the Detail Examinations shall meet the Operator Qualification Requirements and be certified with training documentation for the specific inspections they are conducting.

Subject Matter Experts: The subject matter experts (SME) shall be degreed engineers (or have equivalent pipeline experience and DA Program Manager approval) with appropriate level of expertise and experience to fulfill the functions described in this document. SME qualifications shall be properly documented.

DA Program Manager: Shall be a degreed engineer or have equivalent pipeline experience and certification. The Program Manager shall have 3 - 5 years gas related supervisory experience in maintenance, construction, or engineering/estimating. The Program manager shall also have 3 - 5 years gas related project management experience in transmission or distribution gas, construction or maintenance projects. The Program Manager shall have taken the CGT Corrosion Control training course, and be formally trained on this procedure, RMP-12.

2.5 Definitions

Anomaly: Any deviation from nominal conditions in the external wall of a pipe, its coating, or the electromagnetic conditions around the pipe.

B31G[9]: A method (from the ASME standard) of calculating the pressure-carrying capacity of a corroded pipe.

Cathodic Disbondment: The destruction of adhesion between a coating and the coated surface caused by products of a cathodic reaction.

Cathodic Protection (CP): A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

Close-Interval Survey (CIS): A method of measuring the potential between the pipe and earth at regular intervals along the pipeline.

Cluster: A grouping of stress corrosion cracks (colony). Typically stress corrosion cracks occur in groups consisting of hundreds or thousands of cracks within a relatively confined area. *See Colony.*

Coal Tar Coating: Coal tar-based anti-corrosion coating

Colony: A grouping of stress corrosion cracks (cluster). Typically stress corrosion cracks occur in groups consisting of hundreds or thousands of cracks within a relatively confined area. See *Cluster.*

Crack Coalescence: Joining of cracks that are in close proximity to form one larger crack.

Critical Flaw Size: The dimensions (length and depth) of a flaw that would fail at a given level of pressure or stress.

Defect: An anomaly in the pipe wall that reduces the pressure-carrying capacity of the pipe.

Dent: A depression caused by mechanical means that produces a visible disturbance in the curvature of the wall of the pipe or component without reducing the wall thickness.

Direct-Current Voltage Gradient (DCVG): A method of measuring the change in electrical voltage gradient in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.

Direct Examination: Inspections and measurements made on the pipe surface at excavations as part of direct assessment.

Disbonded Coating: Any loss of adhesion between the protective coating and a pipe surface as a result of adhesive failure, chemical attack, mechanical damage, hydrogen concentrations, etc. Disbonded coating may or may not be associated with a coating holiday. See also *Cathodic Disbondment.*

External Corrosion Direct Assessment (ECDA): A four-step process that combines pre-assessment, indirect inspections, direct examinations, and post-assessment to evaluate the impact of external corrosion on the integrity of a pipeline.

Fatigue: The phenomenon leading to cracking or fracture of a material under repeated or fluctuating stresses having a maximum value less than the tensile strength of the material.

Fault: Any anomaly in the coating, including disbonded areas and holidays.

Fracture Toughness: A measure of a material's resistance to static or dynamic crack extension. It is a material property used in the calculation of critical flaw sizes for crack-like defects.

High-pH SCC: A form of SCC on underground pipelines that is intergranular and typically branched and is associated with an alkaline electrolyte (pH about 9.3). Also referred to as classical SCC.

Holiday: A discontinuity in a protective coating that exposes the pipe steel surface to the environment.

Hydrostatic Testing: Pressure testing of sections of a pipeline by filling it with water and pressurizing it until the nominal hoop stresses in the pipe reach a specified value.

Indication: Any deviation from the norm as measured by an indirect inspection tool.

Indirect Inspection: Equipment and practices used to take measurements at ground surface above or near a pipeline to locate or characterize corrosion activity, coating holidays, or other anomalies.

In-Line Inspection (ILI): the inspection of a pipeline from the interior of the pipe using an ILI tool. These tools are known as *pigs* or *smart pigs*.

Intergranular Cracking: Cracking in which the crack path is between the grains in a metal (typically associated with high-pH SCC).

Investigative Dig: An inspection of a pipeline at a discrete location exposed for examination.

Leak: Product loss through a small hole or crack in the pipeline.

Magnetic Particle Inspection (MPI): A nondestructive inspection technique for locating surface cracks in a steel using fine magnetic particles and a magnetic field.

Maximum Allowable Operating Pressure (MAOP): the maximum internal pressure permitted during the operation of a pipeline.

Mechanical Damage: Anomalies in pipe—including dents, gouges, scratches, and metal loss—caused by the application of an external force.

Metallography: The study of the structure and constitution of a metal as revealed by a microscope.

Near-Neutral-pH SCC: A form of SCC on underground pipelines that is transgranular and is associated with a near-neutral-pH electrolyte. Typically this form of cracking has limited branching and is associated with some corrosion of the crack walls and sometimes of the pipe surface. Also referred to as low-pH or nonclassical SCC.

pH: The negative logarithm of the hydrogen ion activity written as:

$pH = -\log_{10} (a_H^+)$

where a_H^+ = hydrogen ion activity = the molar concentration of hydrogen ions multiplied by the mean ion-activity coefficient.

Pipe-to-Electrolyte Potential: *See Structure-to-Electrolyte Potential.*

Pipe-to-Soil Potential: *See Structure-to-Electrolyte Potential.*

Pressure: A measure of force per unit area.

Remediation: As used in this standard, remediation refers to corrective actions taken to mitigate SCC.

Residual Stress: The locked-in stress present in an object that results from the manufacturing process, heat treatment, or mechanical working of the material.

Rupture: A failure of a pipeline that results from unstable crack propagation and causes an uncontrolled release of the contained product.

RSTRENG[10]: A computer program designed to calculate the pressure-carrying capacity of corroded pipe.

SCCDA: The stress corrosion cracking direct assessment process.

Segment: A portion of a pipeline that is (to be) assessed using SCCDA.

Significant SCC: An SCC cluster is assessed to be "significant" by the Canadian Energy Pipeline Association (CEPA)[2] if the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness **and** the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS. CEPA also defines the interaction criteria.

The presence of extensive and "significant" SCC typically triggers an SCC mitigation program (see discussion under Post-Assessment Step).

Specified Minimum Yield Strength (SMYS): The minimum yield strength of a material prescribed by the specification or standard to which the material is manufactured.

Stress: The force per unit area when a force acts on a body.

Stress Corrosion Cracking: Cracking of a material produced by the combined action of corrosion and tensile stress (residual or applied).

Structure-to-Electrolyte Potential: The potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte.

Terrain Conditions: Collective term used to describe soil type, drainage, and topography. Often used as input in the generation of SCC predictive models.

Transgranular Cracking: Cracking in which the crack path is through the grains of a metal (typically associated with near-neutral-pH SCC).

Voltage: An electromotive force or a difference in electrode potentials, commonly expressed in volts or millivolts.

Yield Strength: The stress at which a material exhibits a specified deviation from the proportionality of stress to strain. The deviation is expressed in terms of strain by either the offset method (usually at a strain of 0.2%) or the total-extension-under-load-method (usually at a strain of 0.5%).

3.0 PRE-ASSESSMENT

3.1 Purpose

The Pre-Assessment is used to collect and analyze historic and current data to prioritize potentially susceptible segments of pipelines and help select specific sites for more detailed evaluation within those segments. The susceptible segments for high-pH SCC are assumed to be those identified based on the criteria in Part A of ASME B31.8S, as listed below. Similar criteria, except for the one regarding operating temperature, may be used for near-neutral-pH SCC.

[2] Canadian Energy Pipeline Association (CEPA), 1650, 801 6th Avenue SW, Calgary, Alberta, Canada T2P 3W2.

3.2 Procedure

During the pre-assessment, data must be compiled and analyzed in order to make informed decisions on the pipeline's suitability for SCCDA. The same or similar data are often included in overall pipeline risk (threat) assessments. The pre-assessment may be conducted in conjunction with other risk-assessment efforts.

Collecting accurate and complete data at this stage is very important. To maximize efficiency, consider collecting the following:

1. Accurate spatial coordinates of pipeline and related data. SCCDA relies on data alignment, which requires accurate spatial positions.
2. Historical CP and coating performance data that indicate the effectiveness of cathodic-protection systems. SCCDA is designed to preclude future SCC. Hence, data that show the cathodic protection system is working properly support the process. Such data may include annual pipe-to-soil surveys, close-interval surveys and bimonthly rectifier and bond current data.
3. Measurements and data from which estimates of corrosion rates and SCC growth rates can be made. SCCDA requires PG&E to estimate (potential) future corrosion rates. Precise corrosion depth measurements and SCC depth and colony number provide a baseline for calculations and future assessments.
4. Measurements and data related to remaining wall thickness at identifiable locations along the pipeline. SCCDA bases its remaining life calculations on the most severe identified corrosion anomaly.
5. Capturing the experience of field personnel with regard to the pipeline history. Field personnel can provide important information needed to resolve areas of uncertainty, such as calculation of corrosion rates and the start and finish locations of SCCDA regions.

The amounts and types of data to be collected will vary with pipeline condition, history, age, etc. This document provides guidelines for determining data collection needs.

Consequences of good data collection include: SCCDA is more likely to be found effectively, indication severity estimation is improved, and the number of confirmatory digs necessary may be reduced.

3.2.1 Data Gathering and Integration

Pre-assessment data fall into five categories:

1. Pipe Related
2. Construction Related
3. Soil/Environment
4. Corrosion Protection
5. Pipeline Operations

In accordance with the requirements of ASME B31.8S, a Company's SCC threat identification should begin with data gathering and integration:

<u>Collect Data for Initial Susceptibility Assessment</u>

PG&E should collect available and relevant data on the system being analyzed. Information to be collected should include but is not limited to the following:

- Diameter, grade and wall thickness
- Pipe manufacturer and type of longitudinal seam weld

- Year/season of construction
- MAOP (% SMYS)
- Type of external coating (pipe section and girth weld coating)
- Operating temperatures and pressures associated with each pipeline system and/or segment of pipeline
- Proximity to compressor station discharge (miles) and
- Hydrostatic retest information

Using the above information, PG&E should identify those portions of its system that are potentially susceptible to SCC. Potentially susceptible regions should be taken as those that:

- The operating stress exceeds 60% of the specified minimum yield strength.
- The operating temperature has historically exceeded 100°F.
- The segment is less than 20 miles downstream from a compressor station.
- The age of the pipeline is greater than 10 years.
- The coating type is other than fusion-bonded epoxy.
- A segment on which one or more service incidents or one or more hydrostatic test breaks or leaks has occurred and has been caused by SCC unless the condition that led to SCC has been corrected.

<u>Data from Prior Excavation Programs</u>

PG&E should collect and review available and relevant information from prior excavation programs on segments identified as potentially susceptible to SCC. Data to be collected should be collected to assess the following:

- Any observed correlations between the occurrence and/or severity of the detected SCC with coating type, terrain condition (i.e. soil, drainage and topography), distance downstream from compressor station, operating stress levels, and operating temperatures.
- The condition of the coating observed at each excavation site.
- The pH of any electrolyte observed under the coating at each excavation site.
- The types of corrosion products observed at each excavation site.
- CP conditions at each site.
- Proximity to dents, welds, etc.

<u>Pressure Data</u>

PG&E should collect and characterize data on pressure cycles associated with each compressor station located within those pipeline segments deemed to be susceptible to SCC. Based on the characterization, PG&E should prepare a prioritized list of pipelines segments based upon the severity of their maximum and average operating stress levels<u>. This is related to the threshold stress required for initiation of SCC. Laboratory studies of initiation of high–pH SCC have shown that stress corrosion cracks initiate above an applied stress level referred to as the threshold stress which is reported as a percent of the yield stress.)</u>

<u>Locations with High Residual Stress</u>

PG&E should identify locations of potentially high stress intensity caused by corrosion, dents, gouges, bends, high welding residual stresses, geotechnical forces. The location of corrosion, dents and gouges should be identified from in-line inspection (i.e. caliper and/or magnetic flux leakage MFL) data, where available, or as a result of activities such as ECDA. The locations of bends can be identified from alignments sheets. The locations of geotechnical forces can be obtained from geotechnical studies undertaken by or on behalf of PG&E. PG&E should prepare a list of locations of potentially high residual stress.

Ability to Conduct SCCDA

PG&E should determine the suitability of conducting SCCDA aboveground surveys on susceptible pipeline segments to determine areas of potential coating disbondment.

Additional Data Collection

PG&E should consider collecting additional data regarding the likelihood and consequences of SCC. Table 3-1 provides guidelines from the NACE Standard Recommended Practice on SCCDA Methodology (RPO 204-2004. The importance ranking in the fourth column is as follows:

- Required (R). Usually important for prioritizing sites.
- Desired (D). May be important for prioritizing sites in some cases.
- Consider (C). Not relevant to prioritizing, but may be useful for record keeping.

Table 3-1. Pipeline Characteristics and Their Impact on SCC Susceptibility

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
	PIPE-RELATED		
Grade	No known correlation with SCC susceptibility.	Background data needed to calculate stress as percent of SMYS.	C
Diameter	No known correlation with SCC susceptibility.	Background data needed to calculate stress from internal pressure.	C
Wall thickness	No known correlation with SCC susceptibility.	Impacts critical defect size and remaining life predictions. Needed to calculate stress from internal pressure.	C
Year manufactured	No known correlation with SCC susceptibility.	Older pipe materials typically have lower toughness levels, reducing critical defect size and remaining life predictions.	C

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Pipe manufacturer	Near-neutral-pH SCC has been found preferentially in the heat-affected zone of ERW pipe that was manufactured by Youngstown Sheet and Tube in the 1950s. Reported to be statistically significant predictor for near-neutral-pH SCC in system model for one pipeline system.	Important factor to consider for near-neutral-pH SCC.	R
Seam type	Near-neutral-pH SCC has been found preferentially under tented tape coatings along DSA welds and in heat-affected zones along some electric-resistance welds. No known correlation with high-pH SCC.	May be important factor to consider for near-neutral-pH SCC.	D
Surface preparation	Shot peening or grit blasting can be beneficial by introducing compressive residual stresses at the surface, inhibiting crack initiation, and by removing mill scale, making it difficult to hold the potential in the critical range for high-pH SCC.[3]	Important factor to consider for both high-pH and near-neutral-pH SCC.	R
Shop coating type	To date, SCC has not been reported for pipe with undamaged fusion-bonded epoxy (FBE) coating or with extruded polyethylene coating.	Important factor to consider for both high-pH and near-neutral-pH SCC.	R
Bare pipe	SCC has been observed on bare pipe in high-resistivity soils.	May be important factor.	D
Hard spots	There have been instances in which near-neutral-pH SCC has occurred preferentially in hard spots, which can be located by ILI that measures residual magnetism.[4]	May be important factor.	D
CONSTRUCTION-RELATED			
Year installed	Impacts time over which coating degradation may occur and cracks may have been growing.	. Age of pipeline used in criteria for selection of susceptible segments in Part A3 of ASME B31.8S.[1]	R
Route changes/ modifications		May be important for accurately locating each site.	C
Route maps/aerial photos		May be important for accurately locating each site.	C

[3] Beavers, J. A., Thompson, N. G., and Coulson, K. E. W., "Effects Of Surface Preparation And Coatings On SCC Susceptibility Of Line Pipe: Phase 1 – Laboratory Studies," CORROSION/93, NACE Paper No. 597, New Orleans, LA, March 1993.

[4] Hard spot failures have been known to occur in 1952 pipe manufactured by A.O. Smith.

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Construction practices	Backfill practices influence probability of coating damage during construction. Also, time between burying of pipe and installation of CP might be important.	Early levels of CP might be important.	D
Surface preparation for field coating	Mill scale promotes potential in critical range for high-pH SCC.	May be discriminating factor.	R
Field coating type	High-pH SCC found under coal tar, asphalt, and tape. Near-neutral-pH SCC most prevalent under tape but also found under asphalt. Weather conditions during construction also may be important in affecting coating condition.	Important factor to consider for near-neutral-pH SCC.	R
Location of weights and anchors	Near-neutral-pH SCC has been found under buoyancy-control weights.		D
Locations of valves, clamps, supports, taps, mechanical couplings, expansion joints, cast iron components, tie-ins, and isolating joints		May be important for accurately locating and characterizing each site.	C
Locations of casings	CP shielding and coating damage more likely within casings.	May be important for accurately locating and characterizing each site.	D
Locations of bends, including miter bends and wrinkle bends	Might indicate unusual residual stresses.	Residual stress may be an important factor.	D
Location of dents	Might indicate unusual residual stresses.	Residual stress may be an important factor.	D
SOILS/ENVIRONMENTAL			
Soil characteristics/ types (Refer to Section 4.)	No known correlation between soil type and high-pH SCC, except for some evidence that high sodium or potassium levels might promote development of concentrated carbonate/bicarbonate solutions under disbonded coatings. Some success has been experienced in correlating near-neutral-pH SCC with specific soil types.	Might be important, especially for near-neutral-pH SCC.	D
Drainage	Has been correlated with both high-pH and near-neutral-pH SCC.	Might be important parameter.	D

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Topography	Has been correlated with both high-pH and near-neutral-pH SCC, possibly related to effect on drainage. Also, circumferential near-neutral-pH SCC has been observed on slopes where soil movement has occurred (apparently external loading induced circumferential low pH SCC is more common that we thought.	Might be important parameter.	D
Land use (current/past)	No obvious correlations have been found, but use of fertilizer might affect soil chemistry as related to trapped water under disbonded coatings.	Might be important parameter	D
Groundwater	Groundwater conductivity affects the throwing power of CP systems.	Might be important parameter.	D
Location of river crossings	Affects soil moisture/drainage.	Might be important parameter.	D
CORROSION CONTROL			
CP system type (anodes, rectifiers, and locations)	Adequate CP can prevent SCC if it reaches under disbonded coatings.	Important parameter.	D
CP evaluation criteria		Background information.	C
CP maintenance history		Background information.	C
Years without CP applied	For high-pH SCC, absence of CP might allow harmful oxides to form on pipe surface. For near-neutral-pH SCC occurring at or near the open-circuit potential, absence of CP could allow SCC to proceed.	Important parameter.	D
CIS and test station information	Although high-pH SCC occurs in a narrow range of potentials (typically between -575 and -825 mV vs $Cu/CuSO_4$), it has been observed on pipe that appeared to be adequately cathodically protected, because the actual potential at the pipe surface can be less negative than the above-ground measurements because of shielding by disbonded coatings. Nevertheless, locations of cracks might correlate with CP history, especially if problems had been encountered in the past . In the case of low-pH SCC, it is difficult to define a range of susceptible potentials due to the shielding process. Nevertheless, laboratory results have shown that low-pH SCC has been observed at the native potential.	Important factor to consider for both high-pH and near-neutral-pH SCC.	D

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Coating-fault survey information	Because SCC requires coating faults, indications of coating condition might help locate probable areas.	Important background information.	D
Coating type and condition	Because SCC requires coating faults, indications of coating condition might help locate probable areas.	Important background information.	R
OPERATIONAL DATA			
Pipe operating temperature	Elevated temperatures have strong accelerating effect on high-pH SCC. For near-neutral-pH SCC, temperature probably has little effect on crack growth rate, but elevated temperatures can contribute to coating deterioration.	Important, especially for high-pH SCC.	R
Operating stress levels and fluctuations	Stress must be above a certain threshold for SCC to occur. Fluctuating stresses can significantly reduce the threshold stress.	Impacts SCC initiation, critical flaw size, and remaining life predictions.	R
Leak/rupture history (SCC)	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	R
Direct inspection and repair history	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	R
Hydrostatic retest history	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	R
ILI data from crack-detecting pig	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	R
ILI data from metal-loss pig	If a metal-loss pig indicates corrosion on a tape-coated pipe where there is no apparent indication of a holiday, the coating is probably disbonded and shielding the pipe from CP, a condition in which SCC—especially near-neutral-pH SCC—has been observed.	May be important.	D
ILI data from caliper tools	Dents located with caliper tools may require investigative digs to detect the possibility of SCC due to stress concentrations	May be important	D

3.2.2 Prioritization

PG&E should prioritize the likelihood and consequences of an SCC incident using a ranking system, and the higher priority segments locations should be scheduled for early assessment (i.e., near the beginning of the baseline assessment program). Other segments can be assessed throughout the implementation period of the baseline assessment plan. For detailed explanation of PG&E's ranking system for SCC see PG&E's RMP06, "Integrity Management Program".

4.0 INDIRECT INSPECTION

4.1 Purpose

Indirect Inspections, which are not always used in SCCDA, can be performed to supplement the data from the pre-assessment step. Data from indirect inspections can serve as input in prioritizing potentially susceptible segments and select the specific sites for direct examination.

4.2 Procedure

Aboveground measurements can include activities such as close interval surveys, coating-fault surveys, geological surveys and characterization.

- Recommended practices are being developed by NACE for close interval surveys. Alternatively, the procedures in Appendix A of NACE Standard RP0502 may be used.
- Recommended practices for coating-fault surveys are also being developed by NACE. Again, the procedures as described in Appendix A of NACE Standard RP0502 may be used.

Other types of data that could be obtained in this step include:

- Locations of dents and bends, found with in-line inspection geometry tools, on pipelines in which the SCC has been associated with such features.
- Areas of coating disbondment and corrosion, located by in-line inspection magnetic-flux-leakage (MFL) tools, on pipelines in which the SCC has been associated with such features.

5.0 DIRECT EXAMINATION

5.1 Purpose

The Direct Examination Step is used (1) to examine the pipe at locations chosen after the pre-assessment and, if applicable, the indirect inspection and (2), if SCC is detected, to assess the presence, extent, type, and severity of SCC at the individual dig sites.

5.2 Procedure

Pipeline segments that are potentially susceptible to SCC are to be subject to a bell hole examination. Pipeline segments that are found to have numerous SCC clusters will require further assessment and testing (beyond the scope of this document), such as inclusion in a hydrostatic test program.

Before the direct examination takes place, dig sites must be selected from the prioritized location list prepared in the pre-assessment step, modified as appropriate by results from indirect inspections. In the absence of a detailed "soils model" for predicting SCC susceptibility, the primary considerations should be the parameters listed earlier in Table 3.1.

5.2.1 Excavations

Pipe must be exposed and the coating removed for magnetic particle inspection (MPI) in accordance with each Company's Bell Hole and defect assessment procedures. Magnetic particle inspection is used to identify possible SCC. Additional details are provided in NACE RPO 204-2004 Appendix B for surface preparation techniques, and Appendix C for MPI. Shallow grinding of local areas can be used to differentiate SCC from benign pipeline anomalies. If SCC is found, in-situ metallography should be used to determine the cracking mechanism (high pH SCC [intergranular] or near neutral pH SCC [transgranular]). Detailed examinations should be conducted in accordance with the NACE SCCDA Recommended Practice. Any cracking and/or external corrosion found should be documented together with relevant dimensions.

Data Collection

Table 5-1 provides guidelines for data collection (taken from the NACE SCCDA Recommended Practice). The importance ranking in the fourth column is as follows:

Required (R): Important element for SCCDA,
Desired (D): May be useful in SCCDA model development.

Consider (C): Useful background information or information used in other analyses