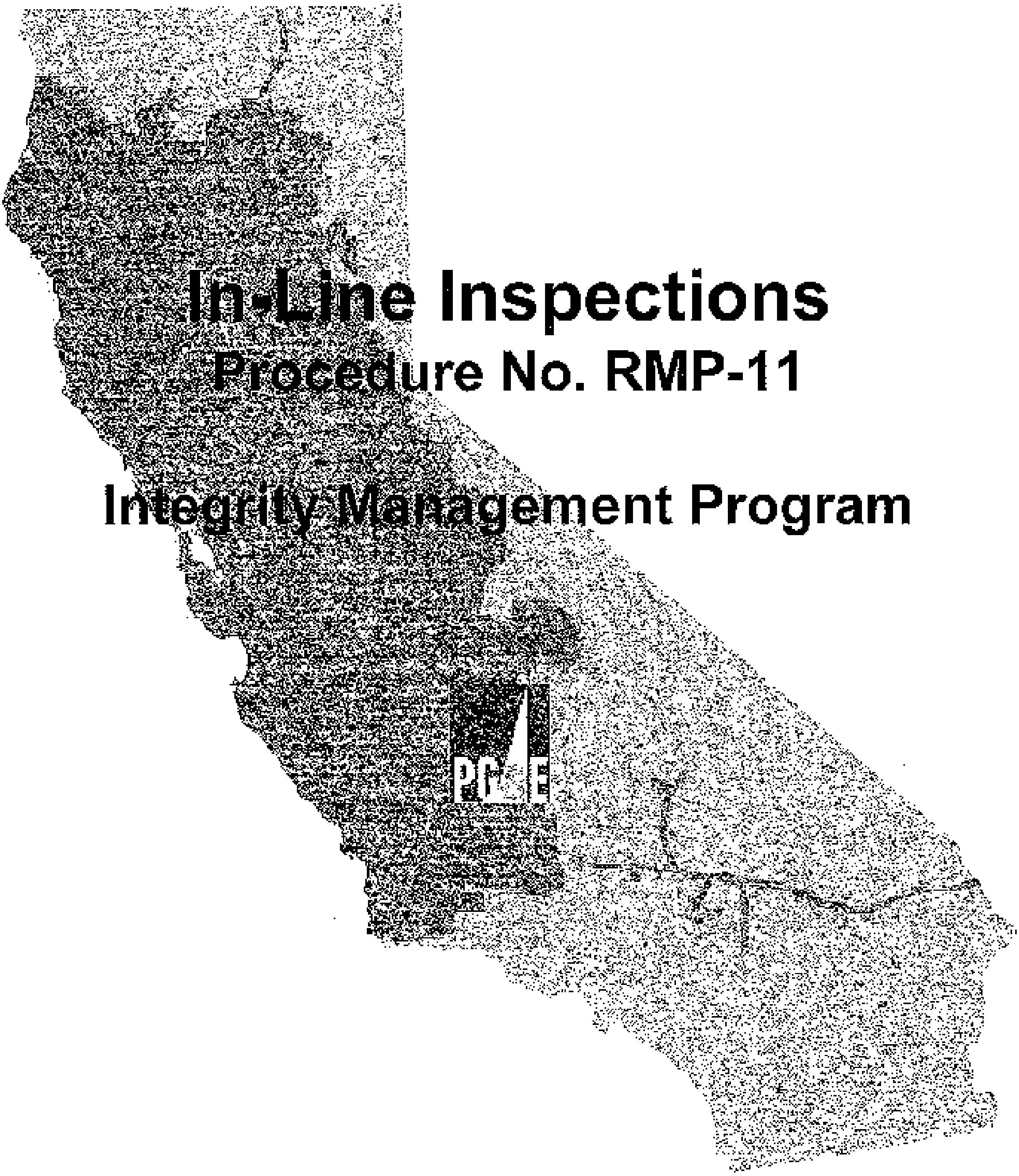
PACIFIC GAS AND ELECTRIC COMPANY



In-Line Inspections

Procedure No. RMP-11

Integrity Management Program

Rev. 2, June 10, 2008

PACIFIC GAS AND ELECTRIC COMPANY

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

Procedure for In-Line Inspections

Procedure No. RMP-11

Integrity Management Program

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2	6-10-08	Revision 2			[illegible]

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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"

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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 <u>PRE-ASSESSMENT</u>

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

[redacted]

- 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.

[redacted]

[redacted]

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST

ID #	Data Element Description	Description: In-Line Inspection Tool Selection	Description: Interpretation and Analysis Of Inspection Results	Requirements: Need[1]	Requirements: Inspection Tool[2]	Requirements: Interpretation and Analysis of Inspection Results[2]	Data Source: GIS	Data Source: As-built Job file	Data Source: Field	Data Source: Districts or Division	Data Source: 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[3]	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	

[redacted]

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
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	

[redacted]

[redacted]

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 C.S, 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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[redacted]

	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-05 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

[redacted]

- 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 <u>IN-LINE INSPECTION</u>

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

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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)

[redacted]

- 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

[redacted]

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 DIRECT EXAMINATION

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.

[redacted]

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.

[redacted]

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.

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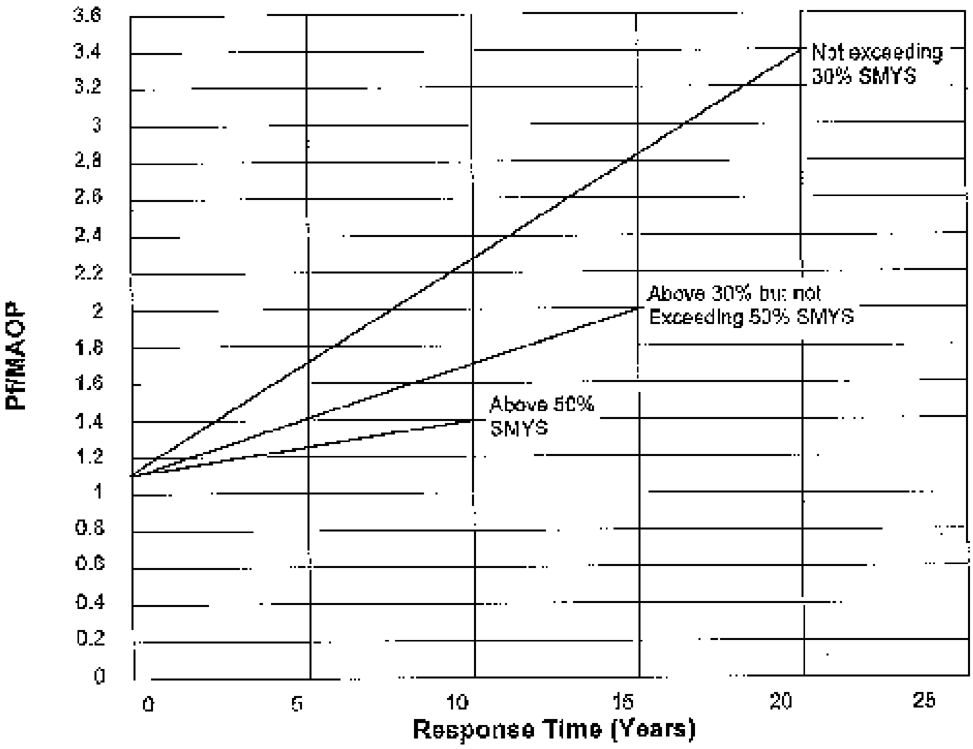


Figure 5.5.2
(ASME B31.8S-2001, Section 7, Figure 4)
TIMING FOR SCHEDULED RESPONSES—TIME DEPENDENT THREATS
PRESCRIPTIVE INTEGRITY MANAGEMENT PLAN

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

[redacted]

- 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.

[redacted]

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.

[redacted]

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 its 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 and 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	R	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 circumferentially 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.

[redacted]

RMP-11

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 50 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.

[redacted]

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

[redacted]

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 EXCEPTION PROCESS

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.

[redacted]

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

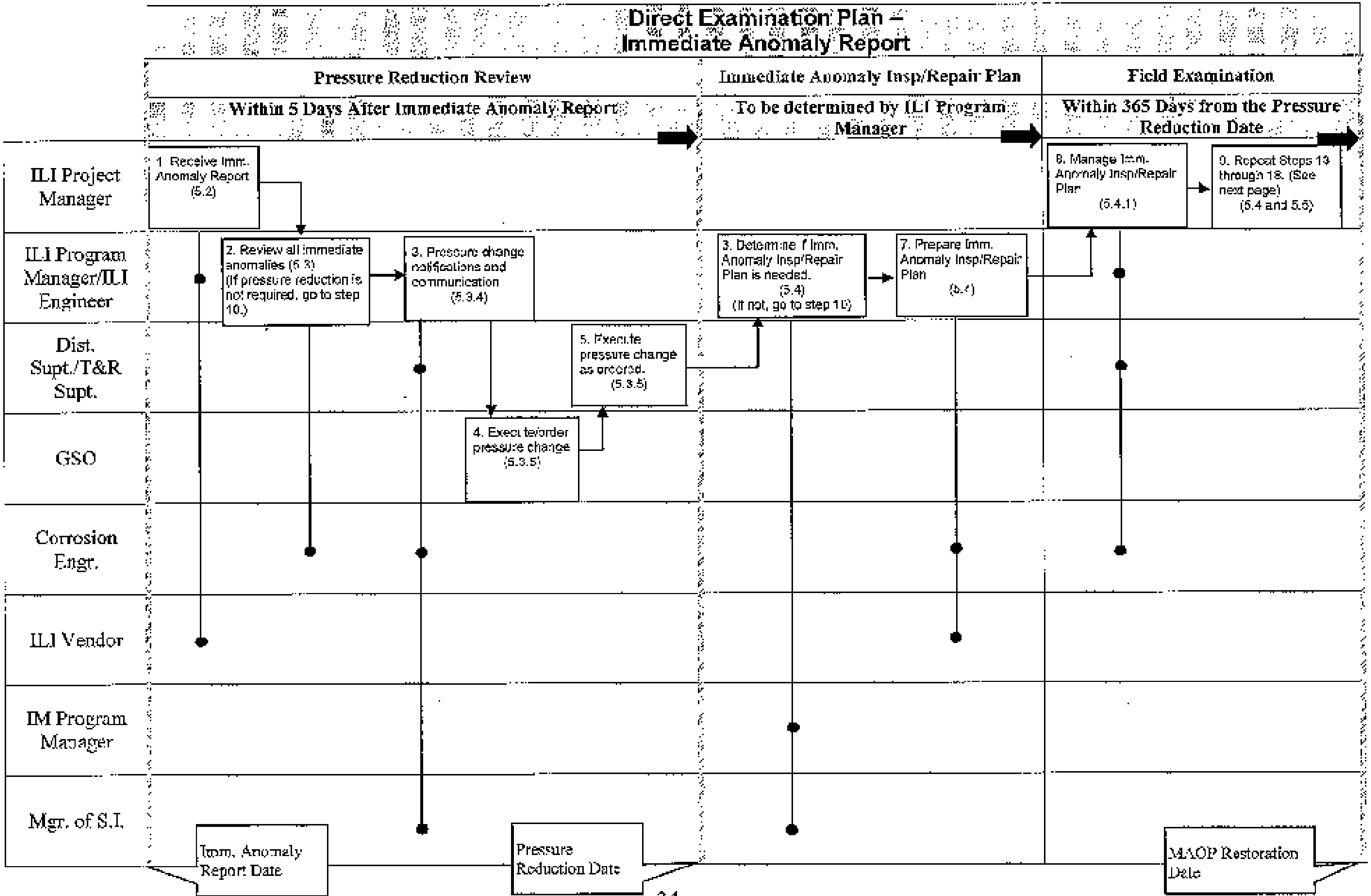
PARAGRAPH	FORM	PURPOSE	RESPONSIBILITIES
3.0 PRE-ASSESSMENT	A	Data Element Check List	ILI Engineer
	B	Sufficient Data Analysis	ILI Engineer
	C	Feasibility Analysis	ILI Program Manager ILI Engineer (This form includes the authorization of Forms A&B also.)
4.0 IN-LINE INSPECTION	D	AGM Locations	ILI Engineer
	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

[redacted]

ATTACHMENT

RMP-11
Attachment A

Direct Examination Process Flow Chart



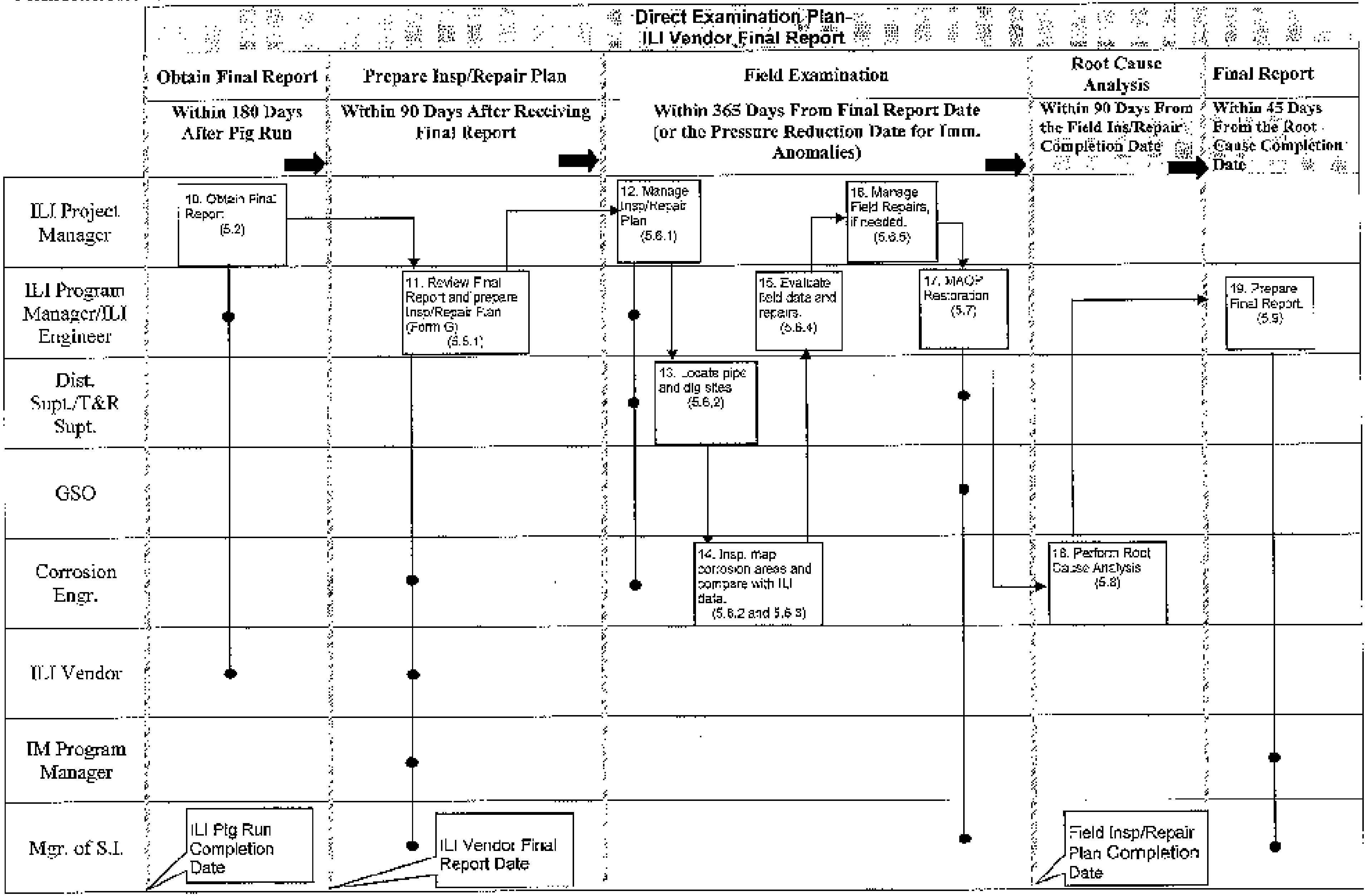
[redacted]

[redacted]

RMP-11

Attachment A

Direct Examination Process Flow Chart



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APPENDIX
ILI Forms

[redacted] GTR0003794

[redacted]

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					Comments
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

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[redacted]

	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]	CIS	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.	

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[redacted]

	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	

[redacted]

	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
											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 3[rd] 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: ______________

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: ______________

[redacted]

[redacted]

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.

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[redacted]

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.

[redacted]

Form E: ILI Vendor Qualification Form

REFERENCE: Section 4.3

ILI 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.

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[redacted]

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

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

Line Number: ______
Starting Mile Point: ______
Ending Mile Point: ______

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.

[redacted]

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 ☐ 1 Year ☐ Other)
☐ Monitor ☐ Effectiveness ☐ 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										

[redacted]

GTR0003805

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 # (ECDA):			
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 5.7.0, 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 ⟶

	0–1	1–2	2–3	3–4	4–5	5–6	6–7	7–8	8–9	9–10
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

[redacted]

DA/ILI

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

DA

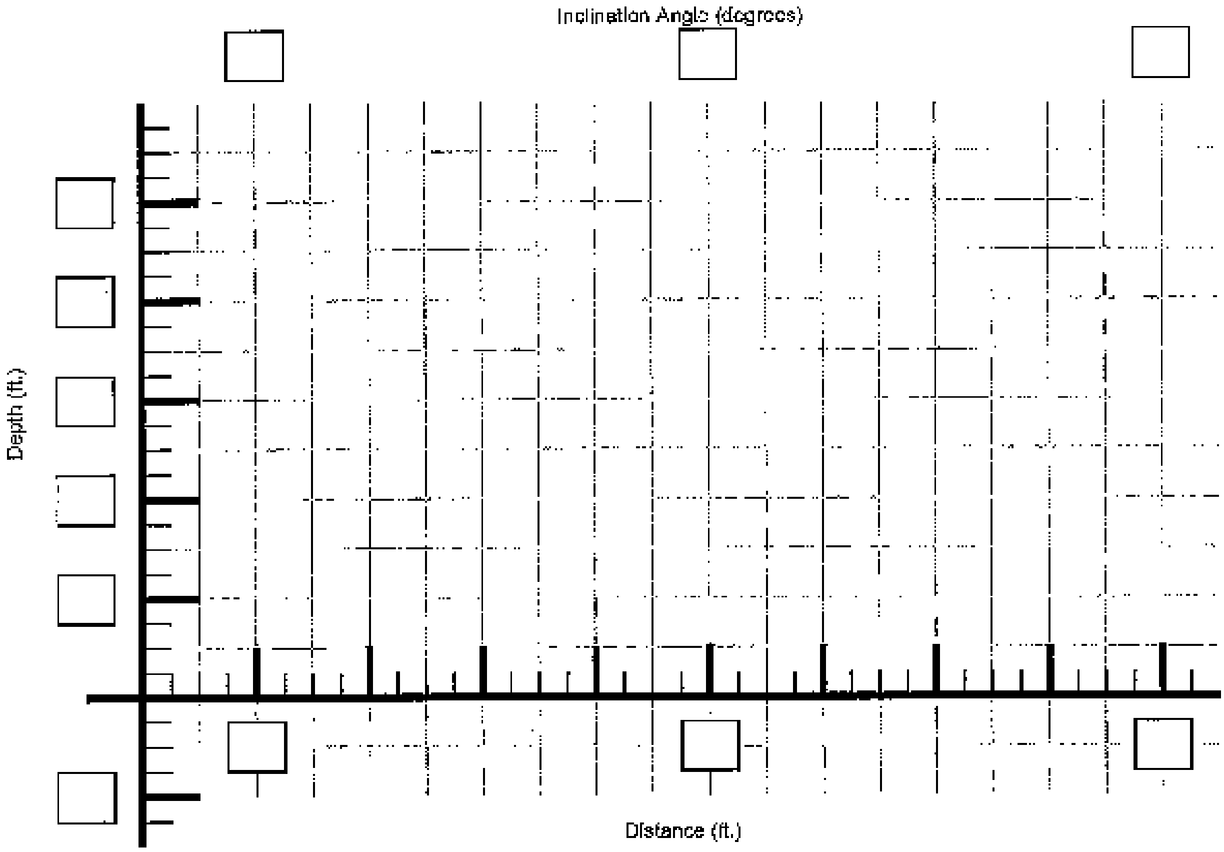
N-Segment: ______________
IMA Number: ______________
Region Number: ______________
Subregion # (ICDA): ______________
Stationing: ______________

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").



Flow ⇨

STATIONING

STATIONING

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

____
____
____

[redacted]

GTR0003807

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

[redacted]

GTR0003808

EXTERNAL PIT DEPTH MEASUREMENT GRID SHEETS

DANEI

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 5.0.2
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 2 OF 2

[redacted] GTR0003809

INTERNAL CORROSION PIT DEPTH GRID

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 6.6.2
Reference Girth Weld: ______
Distance From Girth Weld: ______

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

[redacted]

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 5.0.2
Reference Girth Weld:
Distance From Girth Weld:

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

[redacted]

CORROSION 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: ____________

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

[redacted]

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

[redacted]

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: ________

[redacted]

Form I: Field Examination RSTRENG Summary

Line Number: ______________________

Starting Mile Point: ______________________

Ending Mile Point: ______________________

Reference Section: Section 5.6

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

[redacted]

GTR0003815

RMP-11

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

[redacted]

GTR0003816

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

LINE NUMBER: ______
DATE OF EXCAVATION: ______
MILE POINT: ______
EXAMINATION PERFORMED BY: ______
PROJECT MANAGER: ______
APPROVED BY: ______

ILI LOG DISTANCE: ______
RMP-11 REF. SECTION: 5.8
DIG SITES: ______

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: ______

HT Results Before Excavation: ______

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

Other Information: ______

Review of Existing Damage Mitigation Measures:

[redacted] GTR0003817

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

LINE NUMBER: ________________
DATE OF EXCAVATION: ________________
MILE POINT: ________________
EXAMINATION PERFORMED BY: ________________
PROJECT MANAGER: ________________
APPROVED BY: ________________

ILI LOG DISTANCE: ________________
RMP-11 REF. SECTION: 5.8
DIG SITES: ________________

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

[redacted]

[redacted]

RMP-11

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

[redacted]

Form M: Exception Report

REFERENCE: ________ SECTIONS 7.0

Line Number: ________

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:** ________