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NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C.

EXCERPTS FROM THE
PG&E ECDA PLAN
RMP-09

(100 Pages)

PACIFIC GAS AND ELECTRIC COMPANY

GAS TRANSMISSION & DISTRIBUTION
GAS ENGINEERING

REV 7

Procedure for External Corrosion Direct Assessment

Procedure No. RMP-09

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Alan Eastman, Manager, System Integrity

Rev. No.	Date	Description	Prepared By	Approved By	Approved Manager, System Integrity
0		Initial Issue	CEC		
1		Updated to meet NACE RP-0502-2002	CEC		
2	8-12-03	Updated	ADE		
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5	10-31-05	Updated	RPF	CMW	
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1.0 PURPOSE

The purpose of this procedure is to describe the process of performing External Corrosion Direct Assessment (ECDA) survey on identified buried gas transmission pipeline segments. This procedure is in accordance with the NACE RP 0502-2002 *Pipeline External Corrosion Direct Assessment Methodology* and DOT 49 CFR Part 192 Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines); Final Rule (8-04-04). It provides instructions, guidance, and requirements to assure and document that ECDA assessments are in compliance with the recommended practice and the final rule (8-04-04). It is PG&E's policy to be in compliance with this practice as well as governing regulations and laws.

2.0 INTRODUCTION

External corrosion direct assessment is a structured process that is intended to improve safety by assessing and reducing the impact of external corrosion on pipeline integrity. By identifying and addressing corrosion activity, ECDA seeks to proactively prevent external corrosion anomalies from growing to a size that affects the structural integrity of the pipeline segments inspected.

2.1 Scope

This procedure may be used to evaluate the integrity of pipeline segments that are threatened by external corrosion or third party damage. During the assessment process other types of damage may be identified. In those cases other suitable assessment methodologies shall be used to evaluate the integrity of the pipe segments.

2.2 ECDA Steps

The ECDA methodology is a four-step process that requires the integration of data from multiple indirect field inspections and from direct pipe surface examinations with the pipe's physical characteristics and operating history. The four steps of the process are:

Pre-Assessment: The Pre-Assessment step collects historic and current data to determine whether the ECDA process is feasible, what indirect inspection tools are appropriate, and defines ECDA regions. The types of data to be collected are typically available in GIS, transmission and distribution plat sheets, associated field validation, job estimates, as-builts, maintenance records.

Indirect Inspection(IIT): The Indirect Inspection step covers above ground inspections to identify and define the severity of coating faults, other anomalies, and areas where corrosion activity may have or may be occurring. Two or more complimentary indirect inspection tools are used over the entire ECDA section to provide improved detection reliability under the wide variety of conditions that may be encountered along a pipeline right-of-way.

Direct Examination(DE): The Direct Examination step includes analyses of indirect inspection data to select sites for excavations and pipe surface evaluations. The data from the direct examinations are combined with prior data to identify and assess the threat of external corrosion on the pipeline.

Post-Assessment: The Post-Assessment step covers analyses of data collected from the previous three steps to assess the effectiveness of the ECDA process, identify mitigations steps and determine reassessment intervals.

ECDA may detect other pipeline integrity threats, such as mechanical damage, stress-corrosion cracking, etc. When such threats are detected, the ECDA procedure requires documentation of the threat and addressed through the Integrity Management Plan (RMP-06).

2.3 Roles and Responsibilities

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

2.3.2 ECDA Project Manager: The ECDA Project Manager (PM) is responsible for ensuring that all aspects of the assigned facets of the ECDA projects are conducted in full compliance with this procedure. In addition, the PM is responsible for the effective planning, documenting and communicating the various aspects and stages of the assigned ECDA projects. This procedure has response time requirements. The PM has point responsibility to assure that those time requirements are met throughout the project.

2.3.3 ECDA Project Engineer: The Project Engineer (PE) provides technical evaluations and analyses through out the assessment process. These include, but are not limited to, sufficient data analysis, the creation of Preassessment Reports, ECDA Region Designation, review and evaluation of Indirect Inspection results for the purpose of determining and calling for Direct Examination excavation sites, remaining strength evaluations, the creation of post assessment reports including root cause analysis, long term mitigation and implementation of mitigation.

2.3.4 Field Engineer: The Field Engineer (FE) is responsible for validating the alignment of the pipeline being assessed in the field with the alignment of the pipeline in GIS. They are responsible for using GPS to collect the coordinates of the shape of the pipeline along with other physical information such as surface cover type, location of monitoring points, valves, etc, rectifiers, known foreign crossings, etc. The FE is also responsible for assisting the PE with gathering the necessary documents required for completing the pre-assessment phase of the ECDA process. With experience, an FE may perform pre-assessment analysis.

2.3.5 Inspector: Inspector is responsible for permit compliance and ensure IIT/DE Inspection Personnel comply with ECDA procedure RMP-09.

2.3.6 IIT/DE Inspection Personnel: The **IIT/DE** Inspection Personnel are responsible for conducting the indirect inspections as well as assigned direct examinations. They are responsible for conducting the inspections and tests in accordance with this procedure and other testing procedures that have been referenced in the assessment process.

2.3.7 Supervising Engineer of TIMP: The supervisor is responsible for the supervision of the DA team and the management of all DA programs (ECDA, EC-CDA and Risk Management based DA projects). This position is responsible for ensuring that all phases of the ECDA process are conducted in a timely and compliant manner. This position is also responsible for the creation, revisions, and communication of changes associated with all direct assessment procedures.

2.3.8 Senior Technical Advisor: The Senior Technical Advisor (STA) is responsible for the quality assurance of the technical reports and recommendations provided by the PE for the DA program. The STA may also assist with the creation of pre-assessment reports including root cause analysis, direct examination site selections and writing post assessment reports. The STA is responsible for the management of the ICDA and SCCDA programs.

2.4 Qualifications

The provisions of this procedure shall be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and related practical experience, are qualified to engage in the practice of corrosion control and risk assessment on ferrous piping systems. The specific qualifications are described below. All positions shall review and be familiar with RMP-09. For additional training requirements see CETS Developmental Plan.

2.4.1 **Manager of Integrity Management:** Shall be a degreed engineer and have sufficient gas transmission corrosion related experience.

2.4.2 **ECDA Project Manager:** Shall be a degreed engineer or have equivalent pipeline experience and certification

2.4.3 **Project Engineer:** Shall be a degreed engineer or have equivalent pipeline experience and certification

2.4.4 **ECDA Field Engineer:** The Field Engineer is an entry level position meeting the requirements of the ESC 3100/PG&E contract job description for Field Engineer.

2.4.5 **IIT/DE Inspection Personnel:** The personnel performing the indirect inspections and direct examinations shall meet the Operator Qualification Requirements as well as being certified with supporting training documentation for the specific inspections they are conducting for the ECDA.

2.4.6 **Supervising Engineer of TIMP:** Shall be a degreed engineer or have comparable pipeline experience and certification. The Supervising Engineer shall have 3 - 5 years gas related supervisory experience in maintenance, construction, or engineering/estimating.

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

2.5 Definitions

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

AC: Asphaltic cement concrete (Paved)

Concrete: Portland Cement Concrete with or without steel reinforcement (Paved)

Considered: "Considered" is a recommendation that a data element is taken into account for the selection of indirect inspection tools, ECDA regions, or analysis of test results.

Covered Pipeline: Are pipe segments in a High Consequence Area that meet the characteristics specified by the Office of Pipeline Safety requiring them to be included in the company Integrity Management Plan.

Defect: Per NACE Standard RP0502-2002 definition, an anomaly in the pipe wall that reduces the pressure-carrying capacity of the pipe.

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

Discovery Of A Condition – Per 49 CFR 192.933 (b) "discovery of a condition occurs when an Operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline." For this procedure the completion of the Direct Examination phase per N-Seg or ECDA Region will constitute the completion of "discovery of a condition."

ECDA Region: For the purpose of this document, the definition of the term ECDA Region shall be the same as the ANSI/NACE Standard RP0502-2002 definition, which is "a section or sections of a pipeline that have similar physical characteristics and operating history and in which the same indirect inspections tools are used." An ECDA region (examples, casings, water crossings and bare pipe, etc.) can have multiple N-Segs. See Figure 2.5.

ECDA Section: For the purpose of this document, the definition of the term ECDA Section shall refer to a part of the N-Segment having its integrity assessed using the ECDA process.

First Time: The first time the ECDA methodology is used to assess the integrity of all or part of an N-Seg. Application of ECDA methodology after an In-Line Inspection or pressure test does not constitute a first time assessment.

GIS Pipe Segment or GIS Segment: Is a length of pipe between nodes which has specific pipe characteristics associated with it in PG&E's GIS database.

In Line Inspection (ILI): Pipeline internal inspection mechanism (aka "smart pig") to determine pipe condition including internal / external metal loss and ovality / dents.

NI: No indication found.

N-Segment: For the purpose of this document, the definition of the term N-Segment (N-Seg) is defined as a "numbered" transmission line with a portion of the pipeline identified for assessment using ECDA. An N-Seg consists of one or more ECDA Regions and includes any taps, dregs, gcusts, dfms, dcusts and numbered lines, etc., that are tapped to it. See Figure 2.5.

NT: No testing performed

Project Engineer Discretionary Dig (PEDD): An excavation for direct examination of an indication that is not required by code, but the Project Engineer specifies. For example, shallow locations <30" with corresponding IIT concern for third party damage as well as other IIT signals of concern but do not meet conditions for required excavations.

Random: Per Microsoft Office Word 2003, Encarta Dictionary "Statistics relating or belonging to a set in which all members have the same probability of occurrence" (examples of sets are: Scheduled, Monitor, NI).

Required: "Required" data listed in Table 3.3.1 must be obtained or its exception approved and documented in accordance with Section 7.0 of this procedure.

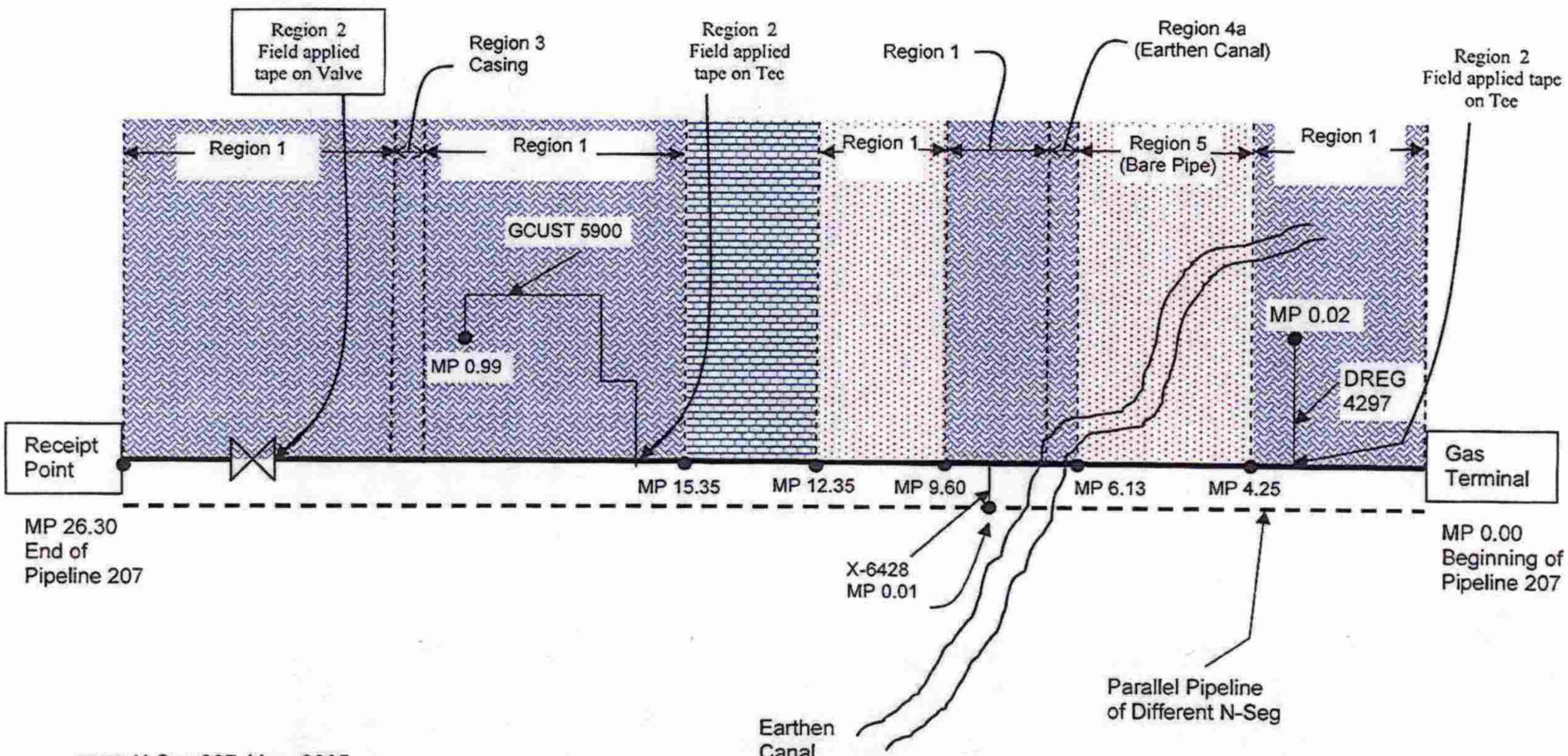
RSTRENG: Computer program that calculates remaining strength of corroded pipe. Is approved by name in 49 CFR Part 192 as an acceptable calculation method.

Subsequent Assessment: An Assessment after the first assessment.

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 or its exception approved and documented in accordance with Section 7.0 of this procedure..

Figure 2.5 – Illustration of the Term N-Seg



N-Seg 207, Year 2005
L-207 MP 0.00 – 4.25, MP 6.13 – 9.60, MP 15.35 – 26.30 (GIS Pipe Segments 142.10 – 156.35, 159.20 – 163.10, 171.14 – 183.0)
GCUST 5900 MP 0.00 – 0.99 (GIS Pipe Segments 501.00, 405.00 – 419.00)
X-6428 MP 0.00 – 0.01 (GIS Pipe Segments 423.1 – 425.6)
DREG 4297 MP 0.00 – 0.02 (GIS Pipe Segment 401)

N-Seg 207, Year 2009
L-207 MP 4.25 – 6.13 (GIS Pipe Segments 156.36 – 159.10)
MP 9.60 – 12.35 (GIS Pipe Segments 163.11 – 164.92)

Not in EDCA Program – No HCA
MP 12.35 – 15.35 (GIS Pipe Segments 164.93 – 171.13)

3.0 PRE-ASSESSMENT

3.1 Objectives

The objectives of the pre-assessment process are to:

- Collect the needed pipeline data to determine the feasibility of conducting an ECDA
- Determine the feasibility of conducting an ECDA of the assessment area
- Select Indirect Inspection Tools (IIT)
- Establish ECDA regions
- Document pre-assessment results

Figure 3.1 shows the process for conducting the pre-assessment step of an ECDA. Each step in the figure will be described in the following paragraphs.

3.2 Pipeline Segments Requiring ECDA

3.2.1 Identification of ECDA Projects: Pipeline segments needing or requiring an ECDA can be identified from multiple sources. Usually the requests for ECDA analysis will come from the Integrity Management, or Risk Management Programs. However, the company may utilize ECDA for other business or operating initiatives. This procedure does not address the identification or ranking processes of pipeline segments requiring ECDA. See RMP-06 for the risk ranking process.

The ECDA scope for a given year should be available in GIS or in the current BAP 12 months before January 1st of the required survey year. This is to allow appropriate time for the pre-assessment phase to be completed. The ECDA scope is developed by the Integrity Management group and made available to the ECDA group. Any additions or deletions to the identified scope should be thoroughly documented and agreed upon by both groups. These additions and or deletions should be communicated in a timely manner to avoid undue hardships and or wasted resources. Any additional HCA's that are identified during the HCA/Risk analysis review should be documented, communicated to Integrity Management and assigned an agreeable future inspection date.

3.2.2 Information Provided With ECDA Request: The request for an ECDA shall provide the following information:

- Integrity Management (SEGMENT) Name (If applicable)
- GIS Segment Number
- Route number
- Starting and ending mile points of requested ECDA sections
- Approval by Email from the **Supervising Engineer of TIMP**
- This information shall reside on the System integrity shared drive under DA/ECDA for the respective year.

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 ECDA. The data is collected to achieve the following objectives of the process:

- Determine the feasibility of conducting an ECDA
- Selection of an Indirect Inspection Tool (IIT)
- Establishment of ECDA regions
- Use and interpretation of results
- For **first time** surveys collect all available corrosion records for the pipeline section to be surveyed. For Second time surveys, the data package needs only to be updated.
- Review the data for additional threats such as Internal Corrosion, Stress Corrosion Cracking or Third Party Damage.

The PE **should** consider these objectives to assure that appropriate and sufficient data is collected to achieve their intent.

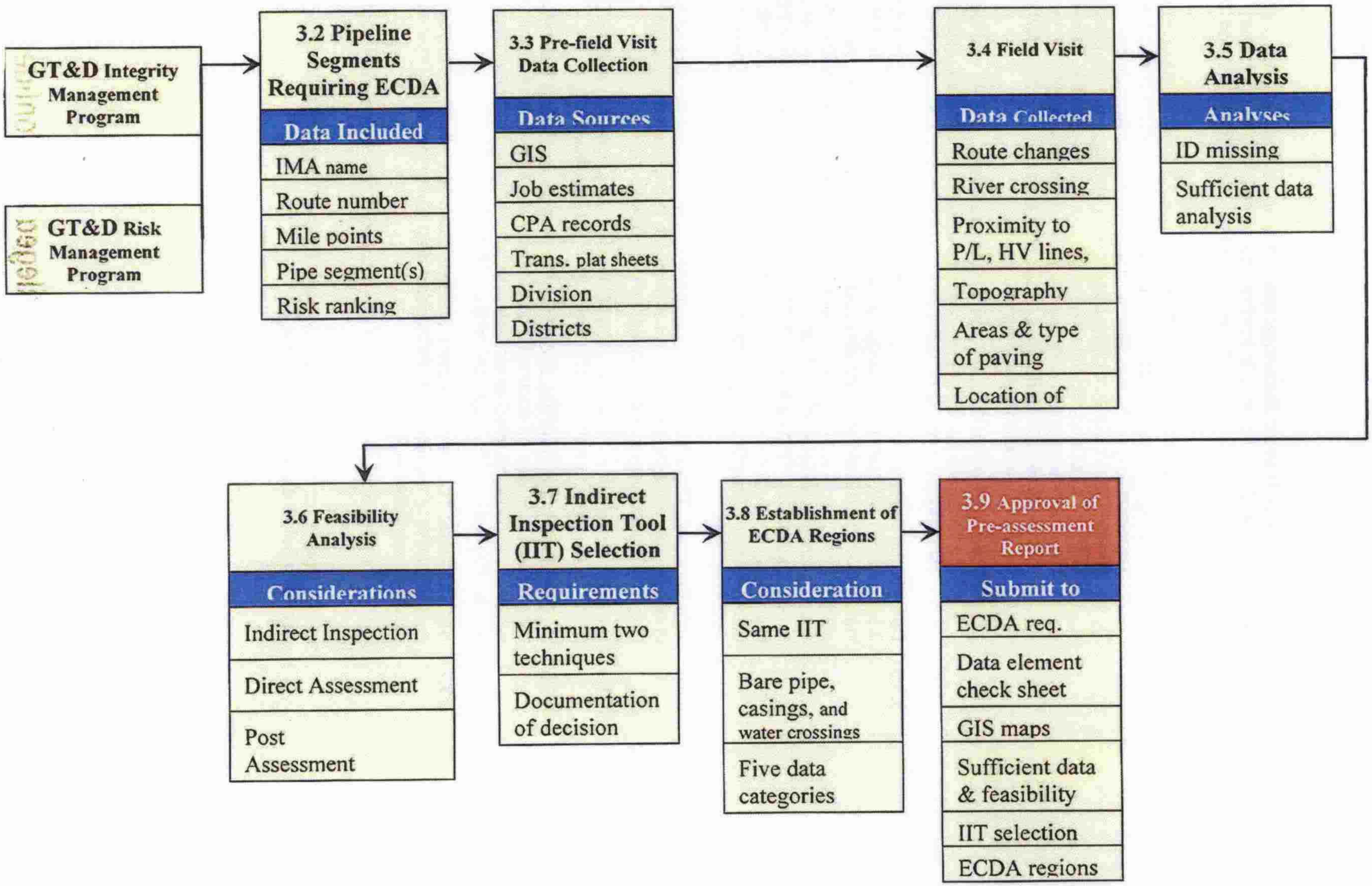


Figure 3.1 Pre-assessment Work Flow

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

3.3.2.1 Pre-Assessment Interview Process: The PE shall facilitate a meeting of key employees to discuss the program and develop a qualitative understanding of the maintenance history of the pipelines to be assessed. An example of the questions to be asked and the people who should attend this meeting can be found in Appendix F. Updates and changes to the Pre-Assessment data, feasibility analysis, II tool selection, and ECDA Regions analysis as a result of the interview shall be documented on the appropriate forms.

3.3.2.2 Pre-Assessment Quality Control Requirements: The PE or designate shall initiate a review of the Pre-Assessment data accuracy, especially for region control points based on coating type and application, etc.

3.3.3 Data Requirements: The "Need" for the data elements is identified in Table 3.3.1 as either "REQUIRED" ,"DESIRED" or "Considered." 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 ECDA Form B: "Sufficient Data List". "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 PE may consider desired data sufficiently important to classify it as "REQUIRED" for a specific ECDA 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 PM should use good judgment on seeking the data elsewhere.

3.3.5 Data Documentation: The collection of information shall be indicated on the "**DATA ELEMENT CHECK SHEET**" (DA Form A) or similar document.

3.3.6 Project Documentation File: Each ECDA project shall establish a suitable filing system to house the documentation of the project. The system shall be organized to allow the effective storage of pipeline data, inspection and analysis results, disposition of findings, and re-inspection intervals.

3.3.7 Updating GIS: The PM shall assure that new information about the physical characteristics of the pipeline or HCA discovered during the pre-assessment process be updated in GIS.

3.3.7.1 FE GPS data should be input into GIS prior to commencement of phase II.

3.3.7.2 Contractor Phase II data should be compared to FE Data for quality assurance before starting excavations.

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST						Usage			Data Source					
ID #	Data Element	Indirect Inspection Tool Selection	ECDA Region Selection	Use & Interpretation Of Results	Need[1]	Inspection Tool[2]	Region Selection[2]	Interpretation Analysis[2]	GIS	Job Est.	Field	Districts or Division	Other	Comments
1.0 Pipe Related														
1.1	Material and Grade	ECDA is not appropriate for nonferrous materials	Special consideration should be given to locations where dissimilar metals are joined		R	C	C	R	X	X				Consider for inspection tools and region selection only when non-ferrous, stainless, or cast iron materials are used. Otherwise use only in direct assessment and post assessment phases.
1.2	Diameter	May reduce detection capability of indirect inspection tools		Influences CP current flow and interpretation	R	C	N/R	R	X	X				Investigate the effect of diameter on detect ability
1.3	Wall thickness			Impacts critical anomaly size	R	N/R	N/R	R	X	X				
1.4	Year manufactured			Older pipe materials typically have lower toughness levels, which reduces critical anomaly size and remaining life predictions	C	N/R	N/R	R						Assume the same as year installed
1.5	Seam Type		Locations with pre-1970 low frequency ERW or flash welded pipe with increased selective seam corrosion susceptibility may require a separate region.	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	R	N/R	C	C	X	X				
1.6	Bare pipe	Limits ECDA application. Fewer available tools	GIS Segments with bare pipe in coated pipelines should be in separate regions.	Specific ECDA methods provided in Appendix A	R	R	R	R	X	X				

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

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST						Usage			Data Sourc					
ID #	Data Element	Indirect Inspection Tool Selection	ECDA Region Selection	Use & Interpretation Of Results	Need[1]	Inspection Tool[2]	Region Selection[2]	Interpretation Analysis[2]	GIS	Job Est.	Field	Districts or Division	Other	Comments
1.7	Pipe Manufacturer			Used to satisfy SCCDA NACE 0204	C	N/R	N/R	C	X	X		X	As-builts	
2. 0 Construction Related														
2.1	Year installed			Impacts time over which coating degradation may occur, anomaly population estimates, and corrosion rate estimates	R	N/R	N/R	R	X	X				
2.2	Recent route changes/ modifications that may not be in GIS		Changes may require separate regions		D	N/R	C	N/R			X	X	As-builts	
2.3	Construction practices		Construction practice differences may require separate regions	May indicate locations at which construction problems may have occurred; e.g., backfill practices influences the probability of coating damage during construction, rocky backfill, etc.	D	C	C	C		X			Engr. Stds. drawings	
2.4	Location of major pipe appurtenances such as valves, taps, tie-in locations and angle points		Significant drains or changes in CP current should be considered separately; special consideration should be given to locations at which dissimilar metals	May impact local current flow and interpretation of results; dissimilar metals may create local corrosion cells points of contact; coating degradation rates may be different from adjacent regions	D	N/R	C	C	X	X	X			
2.5	Locations of casings (including gelled casings)	May preclude the use of some indirect inspection tools	Casings shall be evaluated with PG&E casing protocol	May require operator to extrapolate nearby results to inaccessible regions. Additional tools and other assessment activities may be required	R	R	R	C	X	X	X		Trans. Plat sheets, CPA Records	

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST						Usage			Data Source					
ID #	Data Element	Indirect Inspection Tool Selection	ECDA Region Selection	Use & Interpretation Of Results	Need[1]	Inspection Tool[2]	Region Selection[2]	Interpretation Analysis[2]	GIS	Job Est.	Field	Districts or Division	Other	Comments
2.6	Location of spans	Standard tools would be visual and holiday test	Requires separate ECDA Region.		R	R	R	C	X	X	X	X		
2.7	Location of bends, including miter bends and wrinkle bends		Presence of miter and wrinkle bends may influence region selection	Coating degradation rates may be different from adjacent regions; corrosion on miter and wrinkle bends can be localized, which affects local current flow and interpretation of results	D	C	C	C		X			Trans. Plat Sheet	
2.8	Depth of cover	Restricts the use of some indirect inspection techniques	May require different ECDA regions	May impact current flow and interpretation of results	D	C	C	C			X	X		
2.9	Underwater sections and river crossings	Significantly restricts the use of many indirect inspection techniques	Requires separate ECDA region	Changes current flow and interpretation of results	R	R	R	C	X	X	X			
2.10	Locations of river weight and anchors	Reduces the available indirect inspection tools	May require separate ECDA region	Influences current flow and interpretation of results; corrosion near weights and anchors can be localized which affects local current flow and interpretation results	D	C	C	C		X	X		As-builts	
2.11	Proximity to other pipelines structures, transmission lines and electrified DC rail crossing	May preclude the use of some indirect inspection methods	Regions where the CP currents are significantly affected by external sources may be treated as separate ECDA regions.	Influences local current flow and interpretation of results	D	C	C	C	X		X			May require night time testing.

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST						Usage			Data Source					
ID #	Data Element	Indirect Inspection Tool Selection	ECDA Region Selection	Use & Interpretation Of Results	Need[1]	Inspection Tool[2]	Region Selection[2]	Interpretation Analysis[2]	GIS	Job Est.	Field	Districts or Division	Other	Comments
2.12	Proximity to HV electric transmission structures	May preclude the use of some indirect inspection methods	Regions where the pipeline is significantly affected by external sources may be treated as separate ECDA regions.	Influences local current flow and interpretation of results	D	C	C	C	X		X			
2.13	Location of reinforced concrete caps	May not be possible to assess with IIT	If IIT can be conducted within allowable 5' offset, region type shall be based on coating		R	N/R	N/R	N/R		X		X	Pipeline engineer	
3.0 Soils/Environmental														
3.1	Soil characteristics & types.	Some soil characteristics reduce the accuracy of the various indirect inspection techniques	Influences where corrosion is most likely; significant differences generally require separate ECDA regions	Can be useful in interpreting results. Influences corrosion rate and remaining life assessment	D	C	C	C	X		X			
3.2	Drainage		Influences where corrosion is most likely; significant differences may require separate ECDA regions	Can be useful in interpreting results. Influences corrosion rate and remaining life assessment	D	N/R	C	N/R			X			
3.3	Topography	Conditions such as rocky areas can make indirect inspections difficult or impossible.	Can determine region selection by identifying locations of higher water content soils		D	C	C	N/R			X			
3.4	Land use (current/past)	Paved roads, etc., influence indirect inspection tool selection	Can influence ECDA application and selection	Can be considered in evaluating the potential severity of damage.	R	C	C	N/R	X		X			Asphalt vs. concrete
3.5	Frozen ground	May impact the applicability and effectiveness of some ECDA methods	Pipeline with some frozen areas should be considered in separate regions.	Influences current flow and interpretation of results	R	C	N/R	N/R			X			

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST						**Usage**			**Data Source**					
ID #	**Data Element**	**Indirect Inspection Tool Selection**	**ECDA Region Selection**	**Use & Interpretation Of Results**	**Need[1]**	**Inspection Tool[2]**	**Region Selection[2]**	**Interpretation Analysis[2]**	**GIS**	**Job Est.**	**Field**	**Districts or Division**	**Other**	**Comments**
3.6	Assessment of environmental conditions			May indicate environmentally sensitive areas.	D	N/R	N/R	C	X		X	X		See E-Screen Modified Appendix I
4.0 External Corrosion (EC) Control														
4.1	CP system type (anodes, rectifiers and locations)	May effect ECDA tool selection		Localized use of sacrificial anodes within impressed current systems may influence indirect inspection. Influences current flow interpretation	R	C	C	C			X		CPA Records	
4.2	CP System Boundaries			Can Significantly effect Interruption Plan	R	C	C	C			X	X	CPA Records/ Preassessment Interview	
4.3	Locations Of Isolation Points			Can Significantly effect Interruption Plan	R	C	C	C			X	X	CPA Records/ Preassessment Interview	
4.4	Locations of Connections to Distribution			Can Significantly effect Interruption Plan & Current Distribution	C	C	C	C			X	X	CPA Records/ Preassessment Interview	
4.5	Stray Current sources/locations			Influences current flow and interpretation results	D	N/R	C	C	X		X	X	CPA Records. Past survey reports	
4.6	Test point locations (pipe access points)		May provide input when defining ECDA regions		R	N/R	C	N/R	X		X		CPA Records	
4.7	CP evaluation criteria			Used in post assessment analysis	R	N/R	C	C					CPA Records, PLM	
4.8	CP maintenance history		Coating condition indicator	Can be useful in interpreting the results	R	N/R	C	C					CPA Records, PLM	
4.9	Years without CP applied		May make ECDA more difficult to apply.	Negatively effects ability to estimate corrosion rates and make remaining life predictions	D	N/R	C	N/R		X				
4.10	Coating type-pipe	ECDA may not be appropriate for coatings that cause shielding (coatings with high dielectric constants)		Coating type may influence time at which corrosion begins and estimates of corrosion rate based on measured wall loss.	R	R	C	C	X	X				
4.11	Coating condition	ECDA may be difficult to apply			D	C	C	N/R	X			X	Direct Assessment	

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST						Usage			Data Source					
ID #	Data Element	Indirect Inspection Tool Selection	ECDA Region Selection	Use & Interpretation Of Results	Need[1]	Inspection Tool[2]	Region Selection[2]	Interpretation Analysis[2]	GIS	Job Est.	Field	Districts or Division	Other	Comments
		with severely degraded coatings												
4.12	Current demand			Increasing current demand can indicate areas where coating degradation is leading to more exposed pipe surface area	D	C	C	C					CPA Records	
4.13	CP survey data/history (Compliance reads only)			Can be useful in interpreting the results	D	N/R	C	C					CPA Records PLM	
4.14	Other prior integrity related activities – CIS, ILI runs, etc.	May impact ECDA tool selection- isolated vs. larger corroded areas		Useful post assessment data	R	C	N/R	C	X				Corrosion Group, IMP Library	
5.0 Operational Data														
5.1	Pipe operating temperature		Significant differences generally require separate ECDA areas	Can locally influence coating degradation rates	D	N/R	C	C				Field measu remen ts		Consider when near the discharge of compressor stat. Develop criteria based on distance from compressor
5.2	Operating stress level			Impacts critical flaw size and remaining life predictions	R	N/R	N/R	R	X					
5.3	Monitoring programs (Coupon, patrol leak surveys etc.)		May provide input when defining ECDA regions	May impact repair, remediation and replacement schedules.	D	N/R	C	N/R				Corro sion Group		
5.4	Pipe inspection reports-excavation		May provide input when defining ECDA regions		R	N/R	C	N/R	X					
5.5	Repair history/records, steel/composite repair sleeves, repair locations	May effect ECDA tool selection	Prior repair methods, such as anode additions can create a local difference that may influence region selection.	Provide useful data for post assessment analysis	R	C	C	C	X			X	Form A's	
5.6	Leak Rupture History (EC)				R	N/R	C	N/R	X	X				

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST

						Usage			Data Source					
ID #	Data Element	Indirect Inspection Tool Selection	ECDA Region Selection	Use & Interpretation Of Results	Need[1]	Inspection Tool[2]	Region Selection[2]	Interpretation Analysis[2]	GIS	Job Est.	Field	Districts or Division	Other	Comments
5.7	Evidence of external MIC			MIC may accelerate external corrosion	D	N/R	N/R	C					Corrosion records	
5.8	Type and frequency of third party damage			High third party damage areas may have increased indirect inspection coating fault defects.	R		C	C	X					
5.9	Data from previous over the ground surveys			Essential for pre-assessment and region selection	R	N/R	R	C	X					
5.10	Pressure Test. Dates / Pressure				D	N/R	C	C	X					
6.0 Internal Corrosion (IC) Threat Assessment														
6.1	History of IC leaks	ICDA Procedure	ICDA Region	Useful post assessment data	D	C	D	C	X		X	X		Pipe inspection form
6.2	Topography	USGS data			D	D	D	D	X		X			
6.3	Depth Survey	PCM or Pipe Locator		Need for critical angle determination and low point	D	D	N/R	D	X		X			
6.4	Received gas from gathering or storage lines			To establish threat for potential IC	D	N/R	D	D	X		X			
6.5	Drip Location			To establish history of electrolytes	D	N/R	C	C	X		X			Check drip logs, PLM
6.6	Corrosometer Probe reads			To establish potential internal corrosion threat	D	D	C	D	X		X			
6.7	Corrosion inhibitor solubility, carrier, dose rate, years of treatment, monitoring, detection of inhibitor in downstream liquids			To establish potential internal corrosion threat	R	R	C	C	X		X	X		
6.8	History Of Liquids		Needed to assess IC history	Determines whether historical or current liquids exist.	R	C	C	C	C		X	X	Drip Logs in Divisions/Districts	

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST						Usage			Data Source					
ID #	Data Element	Indirect Inspection Tool Selection	ECDA Region Selection	Use & Interpretation Of Results	Need[1]	Inspection Tool[2]	Region Selection[2]	Interpretation Analysis[2]	GIS	Job Est.	Field	Districts or Division	Other	Comments
6.9	Chemical/Microbial analysis of liquid samples			To establish potential internal corrosion threat	D	D	C	D	X		X	X		
6.10	Acid Gas Partial Pressures				C	C	C	C						District or Corrosion Group
6.11	Line Pressure and Flow Rate(Including fluctuations in pressure and direction)				D	D	C	D	X		X	X		
6.12	Dew Point & Temp				D	D	C	D	X		X	X		
6.13	Previously "pigged"				D	D	C	D	X		X	X		
6.14	Type and locations of current and historic inlets and outlets, tie-ins, taps, insulating joints, drains, drips, cast iron components				R	R	R	R						
6.15	Type of dehydration				R	R	N/R	C						
6.16	Data on liquid upsets				D	C	C	C						
6.17	Corrosion monitoring (LPR probes, weight loss coupons, etc.)				R	R	N/R	C						
6.18	Type of Flow Coating				C	N/R	N/R	C		X		X	As-builts	
7.0 Stress Corrosion Cracking (high pH SCC) Threat Assessment														
7.1	Year of Manufacture			If Pre-1970	D	C	C	C	X					
7.2	Operating Stress Level			> 50%	D	C	C	C	X					

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST						Usage			Data Source					
ID #	Data Element	Indirect Inspection Tool Selection	ECDA Region Selection	Use & Interpretation Of Results	Need[1]	Inspection Tool[2]	Region Selection[2]	Interpretation Analysis[2]	GIS	Job Est.	Field	Districts or Division	Other	Comments
7.3	Operating Temp			> 100 degrees F	D	C	C	C	X					
7.4	Distance from Compressor station			<= to 20 miles	D	C	C	C	X					
7.5	Coating type			other than FBE	D	C	C	C	X					
7.6	Pressure Test. Dates / Pressure			For reasons other than SCC investigations	D									
8.0 Third Party Damage Threat Assessment														
8.1	Review Easement documents for foreign crossings				C	C	C	C						Land Department
8.2	Evidence of new excavation or construction				C	C	C	C						
8.3	Historical concentration of USA tags				C	C	C	C	X					
8.4	Known areas of shallow cover			Review old corrosion surveys for depth information	C	C	C	C	X					Interview Questions, see Appendix F for details
8.5	Pipe inspection reports/repairs				C	C	C	C	X					Interview Questions, see Appendix F for details
8.6	Patrol Records				C	C	C	C	X					Interview Questions, see Appendix F for details
9.0 Hard Spot Threat														
9.1	Threat of hard spots				C	C	C	C						RM Department provided information
10. 0 Casings														
10.1	Year installed				D	D	X	C	X	X				
10.2	Type of casing				D	D	X	D		X				
10.3	Type of end seal				D	N/R	X	D		X				
10.4	Spacer				D	N/R	X	D		X				
10.5	Coated				D	N/R	X	D		X				
10.6	Gelled casings				D	D	X	R	X		X	X		
10.7	History of shorts				D	N/R	X	R			X	X		
10.8	Presence of Vents				D	R	X	R	X	X	X	X		
10.9	Presence of ETS				D	R	X	R	X	X	X	X		

TABLE 3.3.1: PRE-ASSESSMENT DATA LIST						Usage			Data Source					
ID #	Data Element	Indirect Inspection Tool Selection	ECDA Region Selection	Use & Interpretation Of Results	Need[1]	Inspection Tool[2]	Region Selection[2]	Interpretation Analysis[2]	GIS	Job Est.	Field	Districts or Division	Other	Comments
10.10	Water table				D	N/R	X	D	X		X	X		
10.11	Type of soil				D	N/R	X	D	X		X	X		
10.12	Proximity to compressors station				R	N/R	X	R	X		X	X		
11.0 SPANS														
11.1	Location Of Spans	Will Impact IIT Selection	Will Impact Region Selection		R	R	R	C	C		X	X	Span Listings in Divisions/Districts	
11.2	Span Accessibility				D	N/R	N/A	C			X	X		

3.4 Field Visit

3.4.1 General Description: Examining the physical locations where the ECDA 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 Indirect Inspection step of the ECDA process. Hence preparation is key to conducting an effective field visit. Some of the data elements that may require field collection or verification in the field are:

TABLE 3.4.1: TYPICAL DATA COLLECTED

ID	Description	ID	Description
2.2	Route changes in the pipeline that are not yet reflected in GIS	3.3	Topography where it is extremely rocky or steep or where access is difficult. Also low lying areas where soils are wetter for longer periods of time.
2.8	Dramatic changes in the depth of cover	3.4	The type of paving, accessibility due to private lands, crossing or in busy roads or highways
2.9	Details on under water crossings	3.5	The possibility of frozen ground
2.12	Proximity to other pipelines, HVAC transmission lines and rail crossings	4.1	CP systems (impressed, galvanic etc.), location of rectifiers, ETS stations, insulation points
3.1	Soil characteristics(Typically found on A-form)	4.5	Sources of stray current and their proximity to the pipeline
3.2	Drainage along the pipe line and areas where the pipeline crosses seasonal creeks	4.6	Test point locations and access to the pipe
		6.5	Drip Locations

3.5 Data Analysis

Once the Field Visit data is collected the PE shall analyze the data to identify missing REQUIRED data elements, and conduct a Sufficient Data Analysis (Form B). If it is determined that additional threats exist on the line segment in question (i.e., internal corrosion, stress corrosion cracking, or third party damage) then additional assessment methods shall be required and the following parties shall be notified:

Pipeline Engineer (PLE)

Supervising Engineer of TIMP

Manager of Integrity Management

Pipeline Engineering Manager

- **Missing Data:** The PE shall document missing data. The Data Element Check Sheet, Form A, can be used to document the missing data. The GIS pipe segments that are missing data shall be identified on Form B, Sufficient Data List.

3.5.1 Sufficient Data Analysis: The data shall be analyzed to determine if there is sufficient data to conduct an ECDA. 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 ECDA then the reason it is not necessary shall be explained in the Sufficient Data List (Form B).
- **Missing Desired Data**: The PE should review the missing Desired data to identify if any of those data elements are essential to conduct the ECDA. If

some of the missing desired data is essential then it should be explained in the Sufficient Data List (Form B).

- **Sufficient Data List:** The PE shall prepare a Sufficient Data List (Form B) concluding there is sufficient data to conduct an ECDA. This list shall have the analyses described in the two paragraphs above and be signed and dated by the PE, PM and Manager.

3.6 Feasibility Analysis

3.6.1 Analysis: The PE shall integrate and analyze the data collected on the pipeline segments and determine if conditions for indirect inspections can be used and whether the application of the ECDA is appropriate. The PE shall examine the existing data in each of the ten categories in Table 3.3.1 and assess the following:

- **Indirect Inspection:** Can existing indirect inspection tools be applied to the pipe segments identified in the ECDA project and be expected to provide meaningful results on potential locations where the coating is damaged? **(Reference NACE RP0502-2002 3.3.1.1 to 3.3.1.6)**
- **Direct Assessment:** Is it physically and economically feasible to gain access to the pipeline to conduct direct assessment and be expected to gain meaningful data?
- **Post Assessment:** Can it be reasonably expected to be able to determine reassessment intervals of the GIS pipe segments given the existing data?

If the conditions along a portion of the pipeline are such that the above methods of assessing integrity cannot be applied, then this ECDA procedure is no longer applicable and shall be brought to the attention of the Integrity Management Program Manager.

3.6.2 Feasibility Analysis Report: The PE shall prepare the FEASIBILITY ANALYSIS REPORT (Form C) which can be used to present the following information:

- Adverse conditions that may make the ECDA infeasible
- Any special considerations or techniques that need to be incorporated in conducting the ECDA to overcome the adverse conditions
- A conclusion on the feasibility of conducting an ECDA for all the GIS pipe segments in the project
- Signed and dated by the PE and PM.

3.7 Indirect Inspection Tool (IIT) Selection

3.7.1 Number of IIT's: The PE shall select at least two complimentary tools from Table 3.7.1 for each pipeline segment in the study area. The PE may utilize other tools than listed in Table 3.7.1 but shall go through the exception process described in Section 7.0 of this procedure. In addition to the two primary IIT's the PE may select additional inspection techniques to compliment the two IIT's and to gain further corrosion and coating information on the pipeline segments.

3.7.2 Selection Considerations: The PE shall select IIT's based on their ability to reliably detect corrosion activity and/or coating holidays under the specific pipeline conditions for each segment. The PE shall consider the guidance provided in Table 3.7.1, Table 3.7.2, and Table 3.3.1. The PE shall select tools that are complimentary to one another with the guidance provided in Table 3.7.2.

3.7.3 Selection Documentation: The selection of IIT's shall be documented for each pipeline segment. The documentation shall include the name of each technique used, the number of the technique and any special considerations for conducting the inspections. Form D, INDIRECT INSPECTION TOOLS SELECTION, shall be used to document the IIT selections.

TABLE 3.7.1 ECDA TOOL SELECTION MATRIX

Conditions	CIS	DCVG	ACVG	Electro-magnetic (PCM)	UT Guided Wave
Coating holidays	Yes	Yes	Yes	No	Yes
Anodic zones on bare pipe****	Yes	No	No	No	Yes
Near river or water crossings	Yes	Yes	Yes	Yes	Yes
Under frozen ground	No	No	No	Yes	Yes
Stray currents	Yes	Yes	Yes	Yes	No
Shield corrosion activity	No	No	No	No	Yes
Isolated parallel structures	Yes	Yes	Yes	Yes	Yes
Near parallel bonded and/or tied pipe lines	Yes	Yes	Yes	Yes***	Yes
Under HVAC electric transmission lines	Yes	Yes	Yes	Yes***	Yes
Shorted casing	Yes	No	Yes	Yes	Yes
Under paved roads**	Yes	Yes	Yes	Yes	Yes
Uncased crossings	Yes	Yes	Yes	Yes	Yes
Cased crossings	Yes	No	Yes	Yes	Yes
Wetlands	Yes	Yes	Yes	Yes	Yes
Rock terrain, ledges or backfill	Yes	Yes	Yes	Yes	Yes
Exposed Pipe (Visual) *	No	No	No	No	Yes

* Complete Exposed Pipe Inspection per appendix E
** When drilled with contact to electrolyte
*** Influence from parallel structure above or below ground may render data invalid
**** For Bare Pipe procedure see Appendix H

Proprietary Information

TABLE 3.7.2 INDIRECT INSPECTION TOOL GUIDE

Indirect Inspection Tool	Measurement Attributes	Typical Uses	Less Suitable for:	Complimentary Tools
CIS	Measures pipe to soil potentials along the pipeline at intervals typically 3 to 10 foot intervals.	Generally used to assess the performance of CP systems and generally estimating the location of coating holidays. Also can detect interferences, shorted casings, and contact with other metallic structures as well as defective electrical isolation joints.	Pipelines that are below paved areas will require holes to be drilled to the soil. Is not effective at detecting coating systems that have disbonded **and** are shielding, or geological shielding	DCVG, ACVG, Electro-magentic (PCM), Guided wave UT
Electro-magnetic (PCM)	Measures the electromagnetic field attenuation emanating from the pipe induced with an AC signal. Qualitatively ranks coating quality and highlights areas with the largest holidays	Can be used for pipelines under pavement and CP systems that are difficult to isolate.	Not useful determining pipe to soil potential or effectiveness of CP. Is not effective at detecting coating systems that have disbonded **and** are shielding. Influence from parallel structure above or below ground may render data invalid. Steel reinforced concrete may influence data.	CIS, Guided wave UT
DCVG/ACVG	Measures voltage gradients resulting from current pickup and discharge points at holidays. Capable of locating holidays on the pipeline.	Generally used to locate large and small coating holidays on soil covered pipelines for DCVG. ACVG can be used through all surface cover types.	Pipelines that are below paved areas will require holes to be drilled to the soil for DCVG. Is not effective at detecting coating systems that have disbonded **and** are shielding.	CIS, Guided wave UT
Guided Wave UT	Uses guided ultrasonic waves to detect and axially locate interior and exterior wall loss. Can estimate percent cross sectional wall loss. Can examine 50 to 150 feet of pipe from one bell hole depending on the coating type and condition.	Can be used for pipelines under pavement or in casings, pipelines with shielded coatings, or expand the length of pipe examined at a bell hole.	Requires direct access to the pipeline and removal of the coating for collar attachment.	Electro-magnetic (PCM), CIS, DCVG, ACVG

3.8 Establishment of ECDA Regions

3.8.1 **Description:** ECDA Regions are pipeline segments that have similar physical characteristics, corrosion histories; expected future corrosion conditions, and uses the same indirect inspection tools. An ECDA region can have non-contiguous pipeline segments within it.

3.8.2 **Criteria:** The PE shall analyze all the data collected in the Pre-assessment step and assign each pipeline segment to an ECDA region on form E (ECDA Region Report).

3.8.2.1 **Indirect Inspection Methods:** Each region shall use two of the same inspection tools. Reference NACE RP 0502-2002 3.5.1.1.1.

3.8.2.2 **Required Data Elements:** Table 3.3.1 lists the data elements that are REQUIRED for the analysis of the ECDA regions. These elements shall be evaluated in establishing ECDA regions.

3.8.2.3 **Considered Data Elements:** Data elements that are listed as CONSIDERED in Table 3.3.1 should be taken into account when establishing the ECDA region.

3.8.2.4 Pipelines Previously Inspected by ILI: PE should consider ILI data to place pipe segments into ECDA regions.

3.8.3 **Typical Region Descriptions Used in the PG&E System: For region selection based on coating type and application (Field applied Tape) only the main line pipe coating is considered.** Typical region types that can be used in the PG&E system for region selections are as follows:

3.8.3.1 **Region 1** –Coatings such as Hot Applied Asphalt (HAA), Protal 7200, Powercrete (PC, Powercrete J (PCJ), Fusion Bonded Epoxy (FBE), Somastic Coating (SOMA), Coal Tar Epoxy, Wax Tape (WAX), Polyken Tape (TAPE), Xtrucoat (XTRUPL), and Coal Tar Enamel.

3.8.3.2 **Region 2** – Possibly hand applied coating locations with a high probability of installation flaws, including field applied Polyken Tape (TAPE) or Coal Tar Enamel. These locations shall be angle points, valves, tees, and taps to District Reg Stations and large customer meter sets.

3.8.3.3 **Region 3** – Casings – This region type is used for cased crossings. Note, all casings evaluated in a given year, regardless of NSEG, shall be evaluated together as Region 3. See Appendix D.

3.8.3.4 **Region 4** - Water Crossings – This description includes continuously wet areas such as wetlands and rice fields as well as rivers, creek crossing and flood control channels that are earthen rather than concrete or metal lined. Concrete or metal lined canals would not be considered Region 4 unless the concrete or metal is excessively degraded. Earthen water crossings will be tracked using Region 4A and 4B. This change is only to track which earthen water crossings that are surveyable by foot with IIT tools and those that are surveyed by boat and/or diver. Region 4A will be used for the earthen water crossings that are able to be surveyed by foot with IIT tools. Region 4B will be used to track earthen water crossings that are surveyable by boat and/or diver. This separation is only for tracking purposes. Note that all region 4A and 4B water crossings evaluated in a given year regardless of NSEG shall be evaluated together for direct examinations.

3.8.3.5 **Region 5** – Bare – This region type is used for bare pipe. See Appendix H for ECDA Procedure. Note, all bare pipe segments evaluated in a given year, regardless of NSEG, shall be evaluated together as Region 5.

3.8.3.6 Region 6 - Spans\Exposed Piping – This region type is used to describe bridge spans and exposed piping. Note, all Spans\Exposed segments evaluated in a given year, regardless of NSEG, shall be evaluated together as Region 6.(This region includes above ground pipe to meters/regs , piping in vaults as well as spans not considered Region 7)

3.8.3.7 Region 7 - Stations – This region type is used to describe station piping whether it is buried or above ground. See Appendix J for ECDA Procedure. Note, all Stations evaluated in a given year, regardless of NSEG, shall be evaluated together as Region 7.

3.8.3.8 Region 8 – Casings With Atmospheric Corrosion Threat -- This region type is for vented casings within 20 miles downstream of a compressor station or vented casings west of the peak of the coastal mountains.

3.8.4 Documentation: The ECDA Region description (Form E, ECDA Region Report) shall be defined and kept in the Project File. Each ECDA region shall have at least the same two IIT's and one other characteristic that is unique to distinguish it from the other ECDA Regions. The PE shall list all essential characteristics for each region. The ECDA Region Report shall be signed by the PE and reviewed and signed by the Project Manager.

3.9 Approval of Pre-assessment Report

3.9.1 Requirements: A Pre-assessment report shall be submitted to the Manager of Integrity Management or designate for review and approval. **Note: If threats other than external corrosion were identified during the pre-assessment phase then the PE shall detail those threats in this report.**

3.9.2 Contents: The report shall contain forms A through E completed and signed by the Project Manager and the PE. The report may be in the form of a binder, and may also include other supporting data, such as GIS maps, leak data, etc.

3.9.3 Approval: Forms A through E should be reviewed with the Manager of Integrity Management. Recommendations shall be incorporated into the report and the manager shall sign the Form E indicating approval of the Pre-assessment Report.

4.0 INDIRECT INSPECTION

4.1 Objectives: The objectives of the Indirect Inspection process are to:

4.1.1 Locate and define the level of polarization and severity of coating faults, other anomalies, and areas where corrosion may have been or may be occurring

4.1.2 Conduct indirect inspection using at least two complimentary tools over the entire length of each ECDA Region

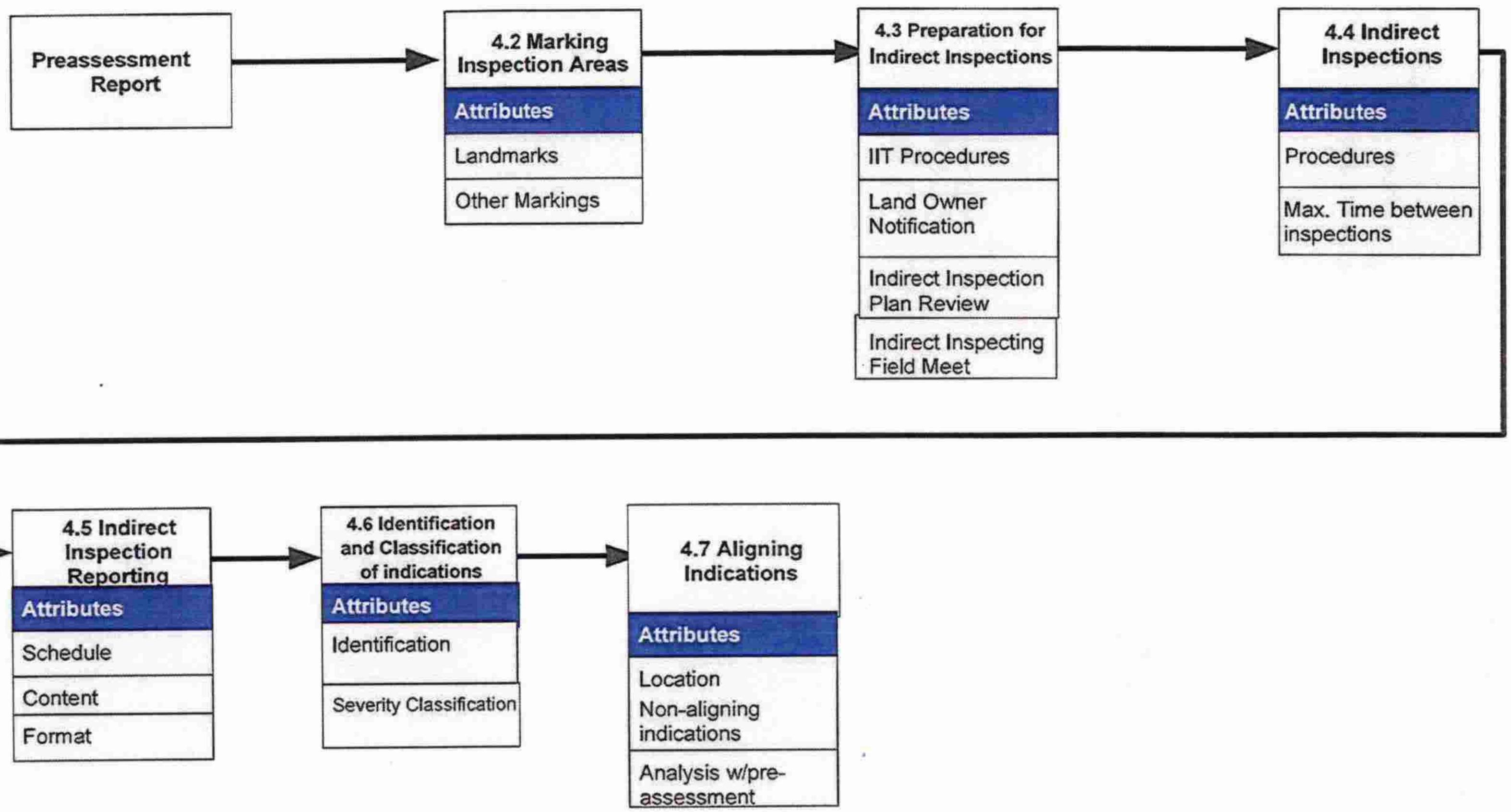
4.1.3 Align and compare the results from the inspections

4.1.4 Identification and classification of indications

4.1.5 Analyze and report results for the Direct Examination step

NOTE: Figure 4.1 shows the process for conducting the Indirect Inspection step of an ECDA. Each step in the figure will be described in following paragraphs.

Figure 4.1 Indirect Inspection Work Flow



4.2 Marking of Inspection Areas

4.2.1 Objective: Prior to conducting indirect inspections each inspection area identified as a specific region in the ECDA REGION REPORT, Form E, shall be clearly marked in the field by the Field Engineer(s) to eliminate any ambiguity as to the boundaries of the regions. The end points of a survey area shall be extended to ensure that the HCA boundaries are covered in the field, typically a 50 foot "buffer" will be used.

4.2.2 Type of Markings: Both ends of each inspection area shall be identified with one or more of the following methods:

4.2.2.1 By a clearly identifiable land mark that has a unique name, such as streets, and buildings

4.2.2.2 Painted markings on the roadway or other pavement with arrows pointing towards the center of the inspection area and with the number of the region.

4.2.2.3 Highly visible stakes, nail markers or other suitable marking device with the Region number on them and an arrow pointing to the center of the region.

4.2.3 HCA Validation: - While the Fielding Engineer (FE) is gathering data while walking the pipeline, it is important to take note of where the high consequence areas (HCAs) are located. It is part of the FE's responsibility to make sure an HCA is valid. If the HCA exists due to an identified site, but that identified site no longer exists or is located far enough away to be outside of the Potential Impact Radius (PIR), this information must be communicated to the Integrity Management department for review. Conversely, if no HCA exists in an area where it appears there should be one, the FE should do more investigation as to whether a new HCA should be established. The complete process for identifying, locating, and documenting HCAs is specified in RMP-06 and RMP-08. RMP-06 also describes how that information is used in the Integrity Management Program.

4.2.4 Documentation: The beginning and end locations of each Region shall be indicated on Form D, INDIRECT INSPECTION TOOL SELECTION.

4.3 Preparation for Indirect Inspections

4.3.1 IIT Procedures: Each IIT shall have a written procedure specifically prepared for that technique. The procedures may be from a vendor who is conducting the inspection or from PG&E where the vendor or employees are performing the inspection to the specified procedure.

4.3.1.1 Procedure Content: Each of the procedures shall contain the following:

4.3.1.1.1 Numbering: The procedure shall have a unique alphanumeric number assigned to it with a revision number.

4.3.1.1.2 General Description: The scope of the procedure and the general theory how the procedure works including what it measures and what it is capable of detecting.

4.3.1.1.3 Limitations: Where the procedure should not be used, what it cannot detect, and its level of sensitivity.

4.3.1.1.4 Procedure Qualification: How the procedure was qualified and where the records are stored that document the qualification.

4.3.1.1.5 **Safety Considerations:** General and specific safety considerations, including, but not limited to following PG&E's clearance procedure and safety regulations, identifying, obtaining and using safety equipment that is required, listing of general hazards, and ensuring stakeholders know what to do in case of an injury/emergency.

4.3.1.1.6 **Instrumentation:** List of equipment by name and model number that is allowed for the inspection. This list should also include special measurement equipment that will be used in case of special field situations such as stray currents.

4.3.1.1.7 **Personnel Qualifications:** The qualification requirements of the personnel conducting the exam including how the personnel were trained on the specific procedure.

4.3.1.1.8 **Step-by-step Instructions:** Specific easy to follow instructions on conducting the survey. These instructions shall include:

- **Calibration:** The calibration of the equipment prior to and during the survey
- **Equipment Connection:** The connection of instrumentation and the set-up of interrupters
- **Pipe Location:** The method of locating the pipe
- **Measurements:** The method of taking measurements and the frequency or interval the measurements should be taken
- **Special Diagnostics:** The techniques and when they are used to address special field situations
- **Distance Measurement:** The method of tracking the distance traveled along the survey and the frequency and locations of geo-references
- **Recording Data:** The recording of data and special diagnostic techniques

4.3.1.1.9 **Data Quality Control**: The contractor shall provide adequate quality control through their procedures to ensure accurate data acquisition and to ensure pipe depolarization does not occur during IIT. These controls and frequency of application shall be documented in the procedure.

4.3.1.1.10 **Prepared and Approval:** The procedure shall document the person who prepared it and the date it was prepared. It shall have been reviewed and approved by a responsible person in the organization that issued it. Both of the above requirements are indicated by signatures and dates.

4.3.1.2 **Procedure Review:** The PE shall review each procedure for adequacy. They shall record their comments for each IIT procedure on the IIT PROCEDURE REVIEW FORM, Form F.

4.3.1.3 **Procedure Filing:** Each approved procedure with any amendments shall be kept in the ECDA program management file.

4.3.2 **Landowner Notification:** A landowner notification plan should be developed for each ECDA Project. The PM is responsible for this plan.

4.3.3 **Indirect Inspection Field Meet:** The vendor shall have a field meet with a representative from the operations and maintenance personnel responsible for maintaining the CP system. The meeting shall be scheduled by e-mail. The PM and PG&E inspector shall be copied on this e-mail. It is recommended that this notification be made at least 2 weeks prior to starting the survey. At this meeting they shall cover the following while referring to the IIT Selection, ECDA Region Forms, and GIS Maps as well as other documents:

4.3.3.1 **ECDA Regions: Review** the boundaries of each ECDA Region.

4.3.3.2 **Cathodic Protection Equipment:** The location and operation of all cathodic protection equipment.

4.3.3.3 **Inspection Tools:** Review all the inspection tools that will be used in the ECDA project. The method to achieve contact with the soil if the area is paved. The use of additional tests for special circumstances as needed.

4.3.3.4 **Access to ECDA Regions:** How the vendor should access the work areas, contacts, schedule, etc.

4.3.3.5 **Schedule:** What exact dates and times the vendor will conduct the survey.

4.3.3.6 **Landowner Contact:** Protocol to follow if landowners question field personnel.

4.3.3.7 **Safety Hazards:** Discuss safety hazards such as traffic, overhead lines, rectifier potentials, flora and fauna, etc..

4.3.3.8 **Notification Procedure:** The vendor shall notify the PM or his designate when abnormal conditions or situations develop. Discuss what these conditions are; such as extreme data, unusual landowner contact, pipeline safety concerns, inspection tool does not appear appropriate, personnel injury, and changes in inspection dates and times.

4.3.3.9 **Changes:** Any changes to the Indirect Inspection Plan shall be documented on the appropriate form. The changes shall be approved as previously stated.

4.3.3.10 Meeting notes and discussion topics shall be documented on Form O and sent to the PM.

4.4 Indirect Inspections

4.4.1 **Breadth of Inspections:** Each of the primary indirect inspections shall be conducted over the entire inspection region. When CIS is performed over asphaltic cement concrete (AC) or steel reinforced Portland Cement Concrete (Concrete) the surface shall be drilled, using a pneumatic or electric drill (with leak survey OQ for electric), and efforts taken to ensure that the test probe is adequately contacting the electrolyte. The ONE CALL service (USA) shall be called prior to drilling. All utilities that are marked as crossing or running in parallel to the pipeline being surveyed in the USA area shall be GPS'd and recorded in the data stream. USA boundaries shall be a minimum of 10' from centerline of pipeline.

4.4.1.1 **3rd and 4th Inspections:** Indirect inspections other than the first and second specified may be conducted in specific areas as determined by the PE and documented on the Form D, INDIRECT INSPECTION TOOL SELECTION.

4.4.1.2 Station Numbering: Each ECDA HCA section shall start with a station of 0+00.

4.4.2 Data Collected: The following data shall be collected for indirect inspections in conjunction with the IIT readings. A data dictionary is provided in Appendix B defining the units of the data elements.

TABLE 4.4.2 DATA ELEMENTS COLLECTED FOR IIT

• Line number	• Type CP equipment**
• Flag number*	• Description of Land use
• Pipe Line Angle Point**	• Valves with Field Labels**
• Depth of pipe every 50 feet and at each change in the configuration of the pipeline**	• Roadway description including street names, driveway addresses, etc.*
• Type Pipeline markers*	• Topographical features*
• Foreign Line Crossings*	• ECDA Region Changes**
• Quality control Data	•

*GPS readings with sub-meter accuracy should be taken for these data elements

** GPS readings with sub-meter accuracy and PCM current attenuation value should be taken for these data elements

4.4.3 Procedures: The indirect inspections shall be performed strictly in accordance with the approved procedures. Any deviation from the procedure shall be approved and documented in the Exception Process of this procedure described in Section 7.0.

4.4.4 Time between Primary Inspections: The PM should have the two indirect inspections conducted as close in time as reasonably possible. The inspections shall not occur more than 90 days apart. If this occurs it shall be approved and documented through the Exception Process in Section 7.0 of this procedure or the earlier indirect inspection shall be redone.

4.4.5 Indirect Inspection Tool Selections Requirements for Cased Pipeline Crossings: For purposes of performing indirect inspections of cased pipeline crossings, the IIT's shall be the Pipeline Current Mapper (PCM), PCM w/A-frame (ACVG), and on-off CIS up to the ends of the casings. All the steps of the casing IIT should be performed at the same time as the indirect inspection of the adjacent uncased pipeline is interrogated with the IIT selected for it (CIS, DCVG, PCM, etc.). If practicable, both ends of the casing should be indirectly inspected in this way.

4.5 Indirect Inspection Reporting

4.5.1 Reporting Time Requirement: The survey data shall be submitted to the PM or the designate no later than 90 days after the completion of the last indirect inspection survey.

4.5.1.1 For ECDA NSEGS that have required re-assessment dates, IIT report must be received 45 days prior to re-assessment date.

4.5.2 Content: The report shall have the following content.

4.5.2.1 Location and Dates: Description of the location where the inspections were performed as well as the dates they were conducted.

4.5.2.2 IIT Types: Description of the indirect inspections that were performed as well as other tests such as soil resistivity, and depth survey. The testing procedures that were followed as well as the personnel conducting the test shall be listed.

4.5.2.3 Current Sources: Rectifier Data Sheet listing the current sources with GPS'd locations that were interrupted with output and ratings of the rectifiers. This sheet will Also include **"As found/As left"** readings.

4.5.2.4 Survey Plots: All IIT results shall be plotted with station distances at 100-foot intervals and at all changes in the configuration of the pipeline. Street names, driveway addresses, type of foreign line crossings (i.e., water crossing, sewer crossing, etc.) and landmarks shall be noted on the chart as well as other test data such as depth surveys, soil resistivity, ETS, rectifiers, anodes, main line valves (MLVs) with field labels, P/L markers, angle points, region and other control points. The period when the tests were conducted shall also be included on the plots.

4.5.2.5 GPS Coordinates: GPS coordinates shall be provided at street names, driveway addresses, type of foreign line crossings (i.e., water crossing, sewer crossing, etc.) and landmarks, as well as ETS's, monitor points, rectifiers, anodes, MLVs with field labels, P/L markers, angle points, region and other control points, etc., and at least every 50 feet.

4.5.2.6 Electronic Format: The report shall be provided in both hardcopy and electronic format.

4.6 Identification and Classification of Indications

4.6.1 Objective: This section describes the process of identifying and classifying indications. The classification is the process of estimating the likelihood of corrosion or other damage occurring at each indication.

4.6.2 Identification Criteria: For each indirect inspection the data shall be analyzed to identify indications. Table 4.6.1 provides the criteria of an indication for each indirect inspection technique for non-cased pipelines and Table 4.6.2 provides same for cased pipelines.

4.6.3 Classification Criteria: The initial severity of each indication shall be classified in accordance with Table 4.6.1 for non-cased crossings and Table 4.6.2 for Cased Crossings.

TABLE 4.6.1 INDIRECT INSPECTION TOOL INDICATION AND SEVERITY GUIDE FOR NON-CASED PIPELINE CROSSINGS

Indirect Inspection Tool	Classification Severe Indications	Classification Moderate Indications	Classification Minor Indications	No Indications (NI)
CIS (Impressed Current)	Any of the following can exist: • <500 mV off (any case) • Less than 600 mV off with a 200 mV change over baseline • Convergence of on/off potential ≤10 mV • Other condition that the PE wants to document	Any of the following can exist: • Between 501 to 600 mV off • Less than 850 mV and 200 mV change over baseline • Convergence of on/off potential between 11 and 50 mV. • Other condition that the PE wants to document	Any of the following can exist: • Between 601 to 850 mV off • Greater than 850 mV and 200 mV change over baseline • Convergence of on/off potentials 51 and 100 mV • Other conditions that the PE wants to document.	• >850 mV off
Close Interval Survey (CIS) with Non-Interruptible Galvanic Anodes Attached to the Pipeline	On pipe to soil measurements less negative than –0.850 V. "AND" A minimum and maximum calculation with a difference of 0.200 V within a 200-ft. sample area.	On pipe to soil measurements less negative than –0.850 V. "AND" a minimum and maximum calculation with a difference of 0.150 V within a 200-ft. sample area.	A minimum and maximum calculation with a difference of 0.100 V within a 200-ft. sample area.	
PCM	Greater than 50% change in 100 feet and remains changed for 4(~200') additional reads within +/- 10% of the new value.	Between 30% and 50% change in 100 feet and remains changed for 4(~200') additional reads within +/- 10% of the new value.	<30 % and remains changed for 4(~200') additional reads within +/- 10% of the new value.	No significant change
DCVG/ACVG	6 or more indications in 100 ft.	3 – 5 indications in 100ft.	2 or less indications in 100ft.	Zero Indications
C-Scan (EM AC Atten.)	Between 60-100%	Between 25-60%	Between 10-25%	<10%
Cell-to-Cell (with soil resistivity)	<10 mV & > 5000 ohm-cm	>10 mV & between 3000 - 5000 ohm-cm	<10 mV & <3000 ohm-cm	
Other				

*In order to distinguish between "No Indication" and "No Test" NI shall be used for no indication and NT shall be used for no test.

4.6.4 Identification and Classification of Indications For Cased Crossings:

TABLE 4.6.2 INDIRECT INSPECTION TOOL INDICATION AND SEVERITY GUIDE FOR CASED PIPELINE CROSSINGS

Indirect Inspection Tool	Severe Indication	Moderate Indication	Minor Indication
Casing Isolation Test (see appendix D)	Metallic Short	Electrolytic Short	Intermittent Electrolytic Short
PCM	Current loss across casing, very little current or signal on downstream side of casing. Large amount of signal (10db+) and current (25%+) loss will indicate direct metal to metal contact. Smaller amounts of signal (10db-) and current (25%-) loss will indicate resistance contact. Current and signal loss at either end of casing, indicating metal to metal contact is at end where loss occurs. Contact not at the ends of casing may be indicated by signal and current loss at point of contact on the casing.	Noticeable (10% +) current loss across casing. Locate signal loss occurs across casing, doesn't return downstream of casing.	No or minimal (less than 10% current loss) across casing. Insignificant locate signal loss (5db or less) across casing. Locate signal loss across casing but signal returns to near upstream level downstream of casing.
PCM w/A-frame	Arrows pointing toward middle of the casing when placed near the ends of the casing. Values of greater than or equal to 75db should be considered metal to metal contacts.	Arrows pointing toward middle of the casing when placed near the ends of the casing. Values of less than 75db can be considered an electrolytic short	No Arrows indicated on read out screen when device is placed near each end of the casing
CIS reads at each end of casing	Full convergence of on-off reads near casing ends	Partial convergence of on-off reads near casing ends	No convergence of on-off reads near casing ends.

Note: If there are A-frame indications at the casing ends without PCM current loss across the casing the problem is coating related at the casing end, generally wire connections.

4.6.5 **Analysis Time Requirements**: The analysis of indications should be completed no later than 1 month after receipt of the data. The analysis should include all paragraphs up through paragraph 4.7 of this procedure.

4.6.6 **Documentation:** The severity of the indications shall be documented on the INDICATION CLASSIFICATION AND DIRECT EXAMINATION FORM, Form G. The following shall be documented on Form G or other appropriate document:

- **Inspection Tool:** The inspection technique used to identify the indication
- **Location:** The location of the indication along the pipeline
- **Severity Classification:** Whether the indication is minor, moderate, and severe.

4.7 Aligning Indications

4.7.1 **Comparison:** The PE shall compare the results from the indirect inspections to determine if they are consistent. The location and severity of the indications from each indirect inspection tool shall be compared to the indications from other indirect inspection tools. Effort should also be made to align any foreign crossing information that was logged in the indirect inspection phase with the survey data collected to assess for the probability of third party damage. If it appears there is a probability of third party damage then the PE may include such a location for direct examination as an effectiveness dig.

4.7.2 **Misalignment:** If two or more indirect inspections tools indicate significantly different sets of indications at locations that do not align with each indirect inspection and if the differences cannot be explained by the inherent capabilities of the tools or specific and localized pipeline features or conditions, additional indirect inspections or preliminary direct examinations shall be conducted. The PE shall do one or more of the following until the discrepancy is explained:

4.7.2.1 **Direct Examinations:** Preliminary direct examinations may be used to resolve discrepancy in the alignment of indications.

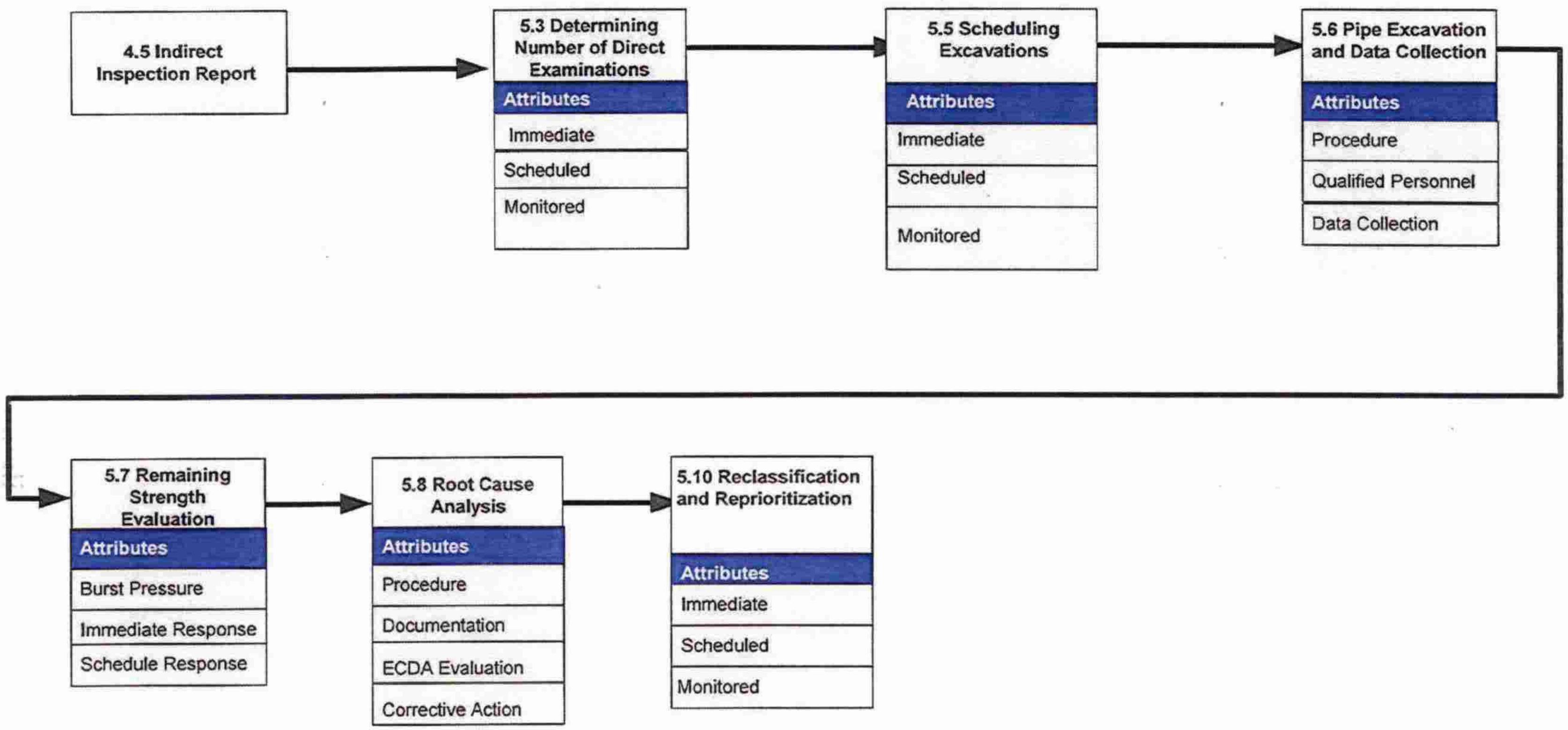
4.7.2.2 **Additional Indirect Inspections:** Additional indirect inspections may be used to resolve discrepancies in the alignment of indications.

4.7.2.3 **ECDA Feasibility Evaluation:** The PE may reevaluate the feasibility of the ECDA and choose to use another integrity assessment technology

4.7.2.4 **Classified Indications Severe:** Any indications where there is a discrepancy in alignment that has not been resolved shall be classified as severe.

Documentation: The vendor shall complete the DIRECT ASSESSMENT PRIORITIZATION ANALYSIS, Form G. The PE shall document any discrepancy and its resolution.

Figure 5.1 Direct Examination Work Flow



5.0 DIRECT EXAMINATION

5.1 Overview

5.1.1 Objective: The Direct Examination step is to calibrate and validate the severity and initial prioritization of indications.

5.1.2 Activities: The Direct Examination Step includes the following activities:

5.1.2.1 Prioritization of indications found during the indirect inspections

5.1.2.2 Scheduling the excavations

5.1.2.3 Excavating the indications and collecting data at areas where corrosion activity is most likely

5.1.2.4 Measurement of coating damage and corrosion defects

5.1.2.5 Evaluation of remaining strength of the GIS pipe segment

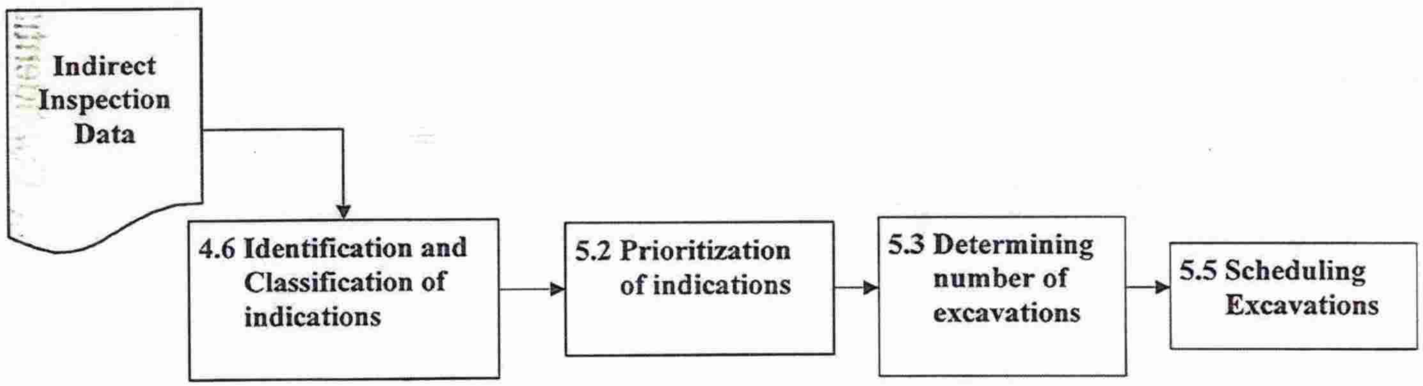
5.1.2.6 Root cause analysis

5.1.2.7 Re-prioritization of other indications

5.2 Prioritization of Indications:

5.2.1 Objective: Prioritization is the process of estimating the need for direct examination of each indication based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion. (Ref. NACE RP0502-2002 5.2.1.1) Figure 5.1 shows the prioritization process from the Indirect Inspection step to the Post Assessment step.

Figure 5.2 - Prioritization Process of Indications



5.2.2 Initial Priorities: All indications shall be initially prioritized into the following categories:

5.2.2.1 Immediate: This priority shall include indications that are likely to have on-going corrosion activity and that, when coupled with past corrosion could pose a threat to the pipeline segments. The following indications, coupled with prior corrosion, pose an immediate threat:

5.2.2.1.1 Isolated Indications: Indications that were prioritized as severe by two IIT inspections as shown in Tables 5.2.2, 5.2.4 for non-cased pipelines and Table 5.2.3 for Cased pipeline crossings.

5.2.2.1.2 Multiple Severe Indications: Multiple severe indications that are in close proximity.

5.2.2.1.3 Discrepancies between IIT: First time ECDA applications, indications that seem to have discrepancies between different IIT techniques.

5.2.2.1.4 Significant Prior Corrosion: Consideration shall be given to other severe or moderate indirect inspection indications in this priority category if significant prior corrosion is suspected or known at or near the indication.

5.2.2.1.5 Difficult to Characterize Indications: Indications for which the likelihood of ongoing corrosion cannot be determined. For example, indications that are a result of interference with CP current.

5.2.2.2 Scheduled: This priority should include indications that may have on-going corrosion activity but when coupled with prior corrosion history does not pose an immediate threat to the pipeline under normal operating conditions. See Tables 5.2.2, 5.2.4 for non-cased pipelines and Table 5.2.3 for Cased pipeline crossings.

5.2.2.3 Monitored: This priority should include indications that are considered inactive or as having the lowest likelihood of ongoing or prior corrosion. See Tables 5.2.2, 5.2.4 for non-cased pipelines and Table 5.2.3 for Cased pipeline crossings.

TABLE 5.2.2 PRIORITIZATION OF INDICATIONS FOR NON-CASED PIPELINES

		CIS			
		Severe	Moderate	Minor	NI
PCM	Severe	I	S	S	M
	Moderate	I	S	M	NI
	Minor	I	S	M	NI
DCVG	Severe	I	S	S	M
	Moderate	I	S	M	NI
	Minor	I	S	M	NI
	NI	I	S	M	NI

I-Immediate, S-Scheduled, M-Monitor, NI-No Indication

Example: With a CIS Minor indication and a PCM Severe indication the result is a Scheduled priority.

Table 5.2.3 PRIORITIZATION OF INDICATIONS FOR CASED PIPELINES

		PCM		
		Severe	Moderate	Minor
CIS	Severe	I	S	S
	Moderate	I	S	M
	Minor	I	S	M
A-frame	Severe	I	S	S
	Moderate	I	S	M
	Minor	I	S	M

Table 5.2.4 PRIORITIZATION OF INDICATIONS FOR PIPELINES PREVIOUSLY ASSESSED USING ILI METHOD

		DA			
		I	S	M	NI
ILI w/ CGR & Tool Tolerance*	I	I	I	I	I
	S	I	S	M	NI
	M	I	I	S	M
	NI**	S	M	NI	NI

* ILI prioritization taken from table 5.5.1 RMP 11, with exception to NI.

** NI ILI prioritization is for any anomaly that does not fall within RMP 11 Table 5.5.1

5.2.3 Indirect Inspection Analysis

5.2.3.1 The PE shall compare the results of the indirect inspections with the pre-assessment results for each ECDA region to see if they rationalize each other. If the assessment results are not consistent with the operating history, the PE must reassess the feasibility of the ECDA.

5.2.4 Indirect Inspection Report

5.2.4.1 The PE shall critically review Form G, DIRECT ASSESSMENT PRIORITIZATION ANALYSIS, and require revision as necessary.

5.3 Number of Excavations

5.3.1 The number of excavations is governed by the number and priority of the indications, as well as if it is the **first time** ECDA is applied to the N-seg. Table 5.3.1 provides a summary of the number of excavations required. Consecutive indications of the same priority will be considered as a single priority. A sampling of this indication at the worst location shall be sufficient to fully assess the actual pipe condition. The typical excavation length is 12 ft. in length for the purpose of exposing approximately 10 ft. of pipeline for direct examination. Approximately 1 foot of pipe on each end of the excavation shall have the coating remain to aid in the transition of the new coating to the old coating.

5.3.2 **Immediate:** All immediate indications shall be planned to be excavated for direct examination. The definition of an immediate indication is a continuous length of pipeline bounded by non-immediate indications. The PE shall determine where along the indication the direct examination shall occur, comments as to why the location was selected shall be included in the comments section in Form-N.

5.3.2.1 **Reprioritization:** If immediate indications are reprioritized to a lower Priority as described in 5.10 the excavation criteria shall be followed for that priority. Note that the worst immediate indications shall be sampled and be sufficient to validate pipeline condition prior to reprioritizing the rest of the immediate indication footage to be scheduled.

5.3.3 **Scheduled:** For all ECDA regions that contain scheduled indications, but did not contain immediate indications, a minimum of one Scheduled indication shall be excavated. When ECDA is applied for the first time an additional Scheduled indication shall be excavated. (Ref. NACE 0502-2002 5.10.2.2.1)

5.3.3.1 If an ECDA region contains scheduled indications and it contained one or more immediate indications, at least one scheduled indication must be subjected to direct examination in the ECDA region at the location considered most severe by the PE. When ECDA is applied for the first time, a minimum of two additional direct examinations shall be performed. (Ref. NACE 0502-2002 5.10.2.2.2)

20% Wall Loss Criteria: If the results of an excavation at a scheduled indication show corrosion that is deeper than 20% of the original wall thickness and that is deeper or more severe than at an immediate indication, at least one more direct examination is required. When ECDA is applied for the first time at least two additional direct examinations shall be performed. (Ref. NACE 0502-2002 5.10.2.2.3)

5.3.3.2 Reprioritization: If Scheduled indications are reprioritized as described in Paragraph 5.10 then they shall follow the excavation criteria for that priority. If one or more Scheduled indications are reprioritized to Immediate then there shall be at least one more excavation per ECDA Region of a Scheduled indication, in rank order. If this occurs, the PE shall review the criteria and the root cause analysis to determine and document future decisions.

5.3.4 Monitored: Monitored indications are not required to be excavated, and can be either monitored, or reprioritized, as described in Paragraph 5.10.

5.3.4.1 If an ECDA Region contains monitored indications but the ECDA region did not contain any immediate or scheduled indication, one excavation is required in the ECDA region at the most severe indication. When ECDA is applied for the first time, a minimum of two direct examinations shall be performed.

5.3.4.2 If multiple ECDA Regions contain monitored indications but did not contain any Immediate or Scheduled indications, then at least one Monitored indication shall be excavated in the ECDA region identified as most likely for external corrosion in the Pre-assessment Step. When ECDA is applied for the first time, a minimum of 2 direct examinations shall be performed.

5.3.5 ECDA Effectiveness Digs: One additional excavation is required to assess the ECDA evaluation process. The location shall be at the indication as determined by the PE. These excavations are applied per segment surveyed.

5.3.5.1 Initial ECDA Projects: Two additional excavations shall be conducted the first time an ECDA survey is performed. One excavation shall be at a Scheduled indication and the other where no indications were detected.

5.3.5.2 Evaluation: The excavation site shall be assessed per the requirements in 5.5. The effectiveness of the ECDA shall be reviewed or an alternate integrity assessment can be used.

5.3.6 Selected Indications: Indications of selected pipe to be excavated shall be shown on Form N, DIG SHEET.

Table 5.3.1 Excavation Summary Table (Per Region)

Priority of Indications Found Sect. 5.2			Required Excavations Sect. 5.3			Trigger of Additional Excavations Sec. 5.2	Additional Excavations Sec. 5.2					Comments
							Per Region			Per N-Seg		
										Effectiveness Digs		
I	S	M	I	S	M		I	S*	M	Initial	Normal	
X			All**							2	1	
X	X		All**	1		First time ECDA		1-2		2	1	Two excavations are required for First time ECDA
X	X	X	All**	1		First time ECDA		1-2		2	1	Two excavations are required for First time ECDA
	X			1		First time ECDA		1-2		2	1	Two excavations are required for First time ECDA
	X	X		1		First time ECDA		1		2	1	Two excavations are required for First time ECDA
		X			1	First time ECDA			1	2	1	
No Indications			1 Excavation based on Pre-assessment			First time ECDA	1 Excavation based on Pre-assessment			2	1	

*See 5.3.3.1 for additional requirements
<u> See 5.3.2.1 for additional guidance</u>**

5.4 EXAMPLES

Problem 1 – Given an N-Seg with 3 regions with the following number of indications determine the minimum number of direct examinations required for the first time ECDA is performed on the N-Seg.

Region 1 has 3 immediates, 9 scheduled and many monitors and "no indications." Region 2 has nothing with a priority higher than monitored indications - no immediates or scheduled.

Region 3 has 3 scheduled and the remaining indications are at least monitors.

Answer – Minimum number of D.E.'s required for the N-Seg = 11.

Solution: Region 1 requires 5 D.E.'s - 3 immediates, 1 scheduled (required), 1 scheduled for 1st time ECDA.

Region 2 requires 2 D.E.'s – 1 monitor is required by the RP in the region identified as most likely for external corrosion in the Pre-assessment Step. An additional monitor is required because it's the first time that ECDA is being applied to the N-Seg.

Region 3 requires 2 D.E.'s – 1 scheduled is required by the RP and a second one is also required because it's the first time that ECDA is being applied to the N-Seg.

The summation of the above breakout for each region above = 9 as the minimum number of D.E.'s required but there are 2 effectiveness digs required per NACE RP0502-2002 –6.4.2 and 6.4.2.1. 1 D.E. required at a scheduled indication and 1 required at any area of no indication. Had this not been the first time that ECDA was applied to the N-Seg then only 1 effectiveness D.E. selected randomly along the N-Seg would have been required.

Problem 2 – Given the same information as in problem 1 above for region 1, it's determined that during the excavation phase there was less than 20% corrosion found on any of the immediates in region 1. However, while excavating the scheduled digs required for that region it was discovered that one of them had no corrosion but the second one had 25% wall loss. It passed RSTRENG and it was determined that the re-assessment life is 10 years. Are more excavations required?

Answer – Yes, at least 2 more excavations are required.

Solution: Because there was greater than 20% wall loss found at the scheduled indication, 1 D.E. is required by the RP and a second one is required because it's the first time that ECDA is applied to the N-Seg. Keep in mind that excavations of the scheduled indications in region 1 may need to continue to be D.E'd until there is no corrosion found that is greater than 20% wall loss found at an indication.

Problem 3 – Given the same information as in problem 1 above for region 1, there was less than 30% wall loss found while sampling the immediates. The remaining pipe wall passed RSTRENG and it was determined that the re-assessment life for that point is 10 years. While sampling the scheduled indications it was determined that less than 20% wall loss was found on the pipeline. Are more excavations required?

Answer – No, additional excavations are not required.

Solution: Because the wall loss due to corrosion that was found on the scheduled D.E. was less than that found on the Immediate D.E. no additional scheduled need to be excavated.

Problem 4 – Given the same information as in problem 1 above for region 3, while excavating the scheduled required for that region one of them had no corrosion, but the second one had 25% wall loss. RSTRENG was performed and it passed. It was also determined that the reassessment life is at least 10 years. Are more excavations required?

Answer – No, additional excavations are not required.

Problem 5 – Determine the number of minimum required excavations for the N-Seg in Problem 1 above, however assume that it is not the first time that ECDA has been performed on the N-Seg.

Answer – A minimum of 7 D.E.'s would be required for the N-Seg.

Solution:

Region 1 – 3 immediates, 1 scheduled.

Region 2 – 1 scheduled

Region 3 – 1 monitored

Effectiveness D.E.'s – 1 required for the N-Seg.

Problem 6 – Given an N-Seg with 3 regions and it's the first time the segment has been ECDA'd, it's determined that there are no scheduled or immediate indications. How many excavations are required for this N-Seg?

Answer – 4 D.E.'s are required for this N-Seg.

Solution: One excavation will be required in the region identified as most likely for external corrosion pre-assessment step. Because it's the first time that ECDA has been applied to this segment, an additional excavation is also required. There is one effectiveness excavation required and because it's the first time ECDA has been performed an additional effectiveness excavation is required (1 monitor, 1 NI).

Note: Effectiveness excavations are per N-Seg and not per region

5.5 Scheduling Excavations: Scheduling of the excavations is to assure that they are performed within the prescribed timeframe and conducted in the most efficient manner. During the scheduling of excavations, an Environmental Screen (E-Screen) is performed to identify environmental impact. See Appendix I E-Screen form.

5.5.1 Schedule: The first excavation per N-Seg should be completed within 180 days of receiving the indirect inspection report. Final schedule of digs will be completed by the PM based on survey data.

5.5.2 Reprioritization Analysis: Sufficient time should be allowed between excavations, so that the data collected from the Direct Examination is analyzed and that a Reprioritization Analysis can be conducted before further excavations take place.

5.5.3 Exceptions: Excavations that do not meet the schedule requirements described in paragraph 5.6.1 shall be documented in accordance with the exception policy described in Section 7.0 of this procedure.

5.6 Pipe Excavation and Data Collection

5.6.1 Procedure: The pipe shall be excavated in accordance with PG&E Utility Standard S4412 "*Preventing Damage to Underground facilities.*"

5.6.1.1 Location and Size of Excavation: The location and size of the excavation site shall be identified and recorded on Form H, DIRECT EXAMINATION DATA SHEET. The center and each end of each excavation shall be located and recorded with a GPS instrument. The length of the excavation shall be physically measured and recorded on Form H. The GPS coordinates shall be stored in an electronic file and copied on the contractor's project CD.

5.6.1.2 Expansion of Excavation: The PM may have the excavation expanded in length if it appears that the severity of corrosion increases beyond the excavation site. The excavation should be done safely, which may include lowering line pressure before continuing the excavation. Excavation shall not be extended solely due to poor coating at the edge of the excavation. The expansion shall be documented on Form H.

5.6.2 Qualified Personnel: Pipe shall be inspected by a person that is qualified by PG&E Operator Qualification Program for the performance of the task "Corrosion Control 03-05." The person shall complete and sign the DIRECT EXAMINATION DATA SHEET (FORM-H).

5.6.3 Data Collection: Collecting data on the condition of the coating and the pipe at the excavation site is a key step of the ECDA process. The collection of data shall follow reviewed-and-approved procedures as described in paragraph 4.3.1. The data that is to be collected is identified in Table 5.6.3. **NOTE: If any corrosion >20% or other damage is discovered, then the area Pipeline Engineer (PLE) shall be notified. It is the PLE's responsibility to ensure repair requirements are determined and implemented, if required, and that the remaining strength is calculated before the pipe is recoated and the bell hole is backfilled.**

5.6.4 Direct Examination clarification For Cased Crossings: For all casings selected for excavation, at least one end of the casing/pipeline shall be exposed and before the end seals are removed, record the casing to soil and pipe to soil readings on Form H.

5.6.4.1 Remove a short section of each end of the casing (at least 3ft which can be performed using a mechanical pipe cutter, Air-Arc gouging, portable lathe, or other approved method by Corrosion Engineering) and inspect the carrier pipe surface for the following:

5.6.4.1.1 Condition of the coating.

5.6.4.1.2 The contents of the annular space. Collect a sample of any electrolyte that may be found, test the pH (on-site) and the MIC count.

5.6.4.1.3 Perform conventional casing electrical tests, as outlined in Appendix D

5.6.4.2 As an effectiveness method, at each exposed cased crossing, the carrier pipe shall be inspected using guided wave technology or approved equivalent (See PG&E procedures for using Long Range Ultrasonic Guidedwave technology). This technology uses surface ultrasonic waves to inspect for wall loss. The results are an average wall thickness. With this technology it is possible to inspect in a qualitative way deep into the casing. The specific procedure used for this direct inspection is specific to the technology used by the vendor. As such the inspection will follow the specific procedures developed by those individual vendors. The vendors will follow their own procedures. Because there are several differing inspection technologies referred to under the "guided wave family umbrella" PG&E will review and modify acceptance criteria prior to use/acceptance. Mike to review GW procedure to see if the entire procedure or just forms???? Start Here

TABLE 5.6.3 DIRECT EXAMINATION DATA COLLECTION REQUIREMENTS

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 bell hole length at the springline location. Also, in the comments section record the type of soil the pipe is bedded in using the United Soil Classification (USC) 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. Note: If no degradation is found, write a note in the comments section reflecting this.
1.9	Map Of Coating Degradation	R	Note in the map the location of all coating holidays, calcareous deposits, etc. The zero reference shall be the farthest upstream location that is inspected.
1.10	Photo documentation	R	Document the coating condition with a digital camera. Photos shall have ruler or other device to determine magnification of photographs showing details of the pipe and coating condition. The minimum requirements shall be to document the following: • The type of cover • Macros showing the cross-section of the excavation (depth of pavement, soil strata, etc.); cross section showing the strata under the pipe especially if rocks are present. • Macros of areas where the jeep test shows holidays • As-found condition of the coating after excavation is complete • General condition of coating • Showing the overall presence or absence of calcareous deposits after the coating has been completely removed but prior to sandblasting. • Presence or absence of rocks embedded in the coating (preferably at the 6:00 position) • Pitting before and after sandblasting • Any unusual characteristics of the pipe or excavation • After recoating • Documenting the as-left condition of the site Macro as well as perspective views shall be recorded. The photo log on page 9 of 10 of the H-form shall be filled out with any necessary descriptions of the photographed areas.

Data Element	DATA Type	Required	Description
1.11	Coating Sample	R	Two samples of the coating shall be obtained. One will be sent to a lab for asbestos testing. The other sample will be stored for physical examination and aid in determining root cause. This sample may also be used to determine the electrical and physical properties of the coating as well as for performing microbial tests. This sample shall be obtained from an area where the worst pipe damage was found, if possible. This sample shall be given to the PE
1.12	Under coating liquid pH analysis	R	If any liquid is detected underneath the coating the pH shall be determined with pH litmus paper. This test infers the relative level of CP reaching the pipe surface.
1.13	Corrosion Product Removal	R	Carefully remove any corrosion deposit for analysis. The presence or absence of corrosive species in the corrosion products can guide the root cause analysis. Analysis may include, but is not limited to, MIC testing, chemical testing, and in some cases XRD testing. MIC testing is required for corrosion products when corrosion greater than 20% is found. Note in comments section if MIC testing was performed and attach results to H-form
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	D	Measure the bare pipe surface temperature. This factors into the tendency for coating to disbond and SCC susceptibility. Measure the circumference of the pipe using a pi tape or other suitable device and compute the actual outside diameter of the pipe.
2.2	Weld Seam Identification	D	The type of weld seam shall be identified and recorded. It will be used to compare with GSAVE, and the presence of brittle seam welds could also be determined. If the seam type cannot be determined, check that box. In some cases it will be necessary to perform a macro etch to locate and characterize the weld type and condition. The macro will only be done when specifically called for by the PE Recoating of the pipe and backfilling of the bell hole will not be allowed unless the long seam has been identified or there is no external corrosion.
2.3	Girth Weld Coordinates	R for ILI	This is required for ILI inspections. ILI keys on the nearest girth weld to determine the location of the bell hole and to compare to ILI girth weld data.
2.4	Other Damage	R	Other damage to the pipe surface that can be visually detected shall be recorded, and **immediately** reported to PG&E. Examples of such damage would include gouges, cracking, dents and out of roundness.
2.5	UT Wall Thickness Measurements	R	Ultrasonic wall thickness shall be taken at every quadrant on the pipe to establish original/nominal wall thickness. In cases where an ICDA pre-assessment has been performed, a UT grid shall also be obtained at the 6:00 location for a length of 1-foot circumferential by 1-foot axial. Grid size shall be 1"x1". The minimum thickness measured in each grid box shall be recorded. The grid shall be located at the low end of the pipe. This ICDA grid and angle of inclination shall be recorded on page 6 of 10 on the H-form.
2.6	Wet Fluorescent Magnetic Particle Inspection	R	For determining the presence or absence of SCC this test shall be performed. Only the AC yoke method shall be used. Surface preparation shall be light sandblasting. On occasion the PE 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. Note: If no corrosion >20% is found, a note in a text box on the grid is required stating "No Corrosion >20% Found".
3.0	**Pipe Recoat Data**		

Data Element	DATA Type	Required	Description
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. Verify conformance to SSPC SP-10 near white metal surface condition.
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 PE 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. **The coupon test station shall be installed per PG&E Gas Standard & Specification O-10.2 in a minimum of 3'x3'x3' cube of native soil. If the dig will require import backfill, enough native soils shall be retained to satisfy the 3' cube.**
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.

TABLE 5.6.4 DIRECT EXAMINATION DATA COLLECTION REQUIREMENTS FOR CASED CROSSINGS

NOTE: REFER TO PG&E WORK PROCEDURE 4133-04 FOR TECHNICAL GUIDANCE.

Data Element	DATA Type	Required	Description
1.0 Before Casing Removal (As Found)			
1.1	Case to Soil Potential Before Portion of Casing is Removed	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 casing. These potentials may help identify dynamic stray currents, as well as help in determining the root cause of any corrosion present (active vs. inactive).
1.2	Pipe to Soil Potential Before Portion of Casing is Removed	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 carrier pipe. These potentials may help identify dynamic stray currents, as well as help in determining the root cause of any corrosion present (active vs. inactive) and casing contacts.
1.3	Casing Type	R	Check the appropriate box to indicate the correct casing type.
1.4	Measured Casing Diameter	R	Measure the circumference of the pipe using a pi tape or other suitable device and compute the actual outside diameter of the pipe.
1.5	Casing Condition	R	Document the casing condition. If the casing appears to be damaged by natural or foreign causes, explain the appearance and possible cause(s) for damage.
1.6	Casing Coating	R	Document if the casing is coated. Explain what type of coating is present and its condition. Three conditions could exist (1) coating is in good condition and completely adhered to the casing.; (2) Coating partially disbanded and/or degraded; (3) The coating is significantly disbanded or missing, i.e., most of it comes off with soil.

Data Element	DATA Type	Required	Description
1.7	Casing Orientation	R	Check the appropriate box to reflect the slope of the casing end.
1.8	Vent	R	Document if a vent pipe at the casing end is present and at what clock position it attached to the casing.
1.9	Water Presence	R	Indicate if water is present inside the casing and estimate the approximate amount of water in gallons.
1.10	End Seals & Spacers	R	Document if an end seal is present. Note the condition of the end seal and its configuration. Photograph if necessary to document condition. Document if spacers are present and the number present.
2.0 After Portion of Casing Removal (As Left)			
2.1	Portion of Casing Removal	R	Document the length of casing removed and what method was used to remove the casing. A minimum of three feet of casing must be removed unless otherwise approved by the PM.
2.2	Casing Flush	R	Document that casing annulus was flushed clean and the method used to carry out the process.
2.3	Vent Clock Position	R	Note the clock position of the connection between casing and the installed vent pipe. The installation shall be at the 12:00 O'clock for the high side and at the 6:00 O'clock position for the low side. Refer to PG&E Work Procedure 4133-04.
2.4	Diameter of Vent Pipe	R	Measure the circumference of the vent pipe using a pi tape or other suitable device and compute the actual outside diameter of the pipe. Refer to PG&E Work Procedure 4133-04.
2.5	Diameter of Vent Opening in Casing	R	Document the diameter of the opening in the casing where the vent pipe connects to the casing. Refer to PG&E Work Procedure 4133-04.
2.6	Wave guides Installed	R	Document if waveguides have been installed. See Appendix D for wave guide installation instructions.
2.7	Spacers Installed	R	Document if spacers have been installed. Refer to Gas Standards & Specifications A-70 and A-73 for installation requirements. Any deviation from A-70 or A-73 must be approved by the PM.
2.8	End Seals Installed	R	Document if end seals have been installed and the type used. Refer to Gas Standards & Specifications A-70 and A-73 for installation requirements. Any deviation from A-70 or A-73 must be approved by the PM.
2.9	End Seal Pressure Test	R	Document that the end seals pass a 5 psi pressure test. Refer to PG&E Work Procedure 4133-04.
2.10	Vent Air Flow Test	R	Document that, through the vent, the casing is able pass an air flow test using a high volume compressor. Refer to PG&E Work Procedure 4133-04.
2.11	Case to Soil Potential After Portion of Casing is Removed	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 casing. These potentials may help identify dynamic stray currents, as well as help in determining the root cause of any corrosion present (active vs. inactive) and clearing casing contacts.
2.12	Pipe to Soil Potential After Portion of Casing is Removed	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 carrier pipe. These potentials may help identify dynamic stray currents, as well as help in determining the root cause of any corrosion present (active vs. inactive) and clearing casing contacts.
2.13	Type B Test Station Installation	R	Document that a Type B test station is installed per Gas Standards & Specifications O-10.
2.14	End of Casing GPS Coordinates	R	Document the Northing and Easting GPS coordinates of the casing end.

5.7 Remaining Strength Evaluation

5.7.1 Objective: The objectives of the remaining strength calculations are three fold:

- **Predicted Burst Pressure:** To determine the predicted burst pressure at the corroded area and assure it meets the Area Class Location Design Requirements.
- **Reprioritization:** Provide input into the reprioritization process to evaluate if the remaining indications are in the appropriate Priority.
- **Reassessment:** Provide input in determining the re-inspection interval in the Post Assessment Step of this procedure.

5.7.2 Predicted Burst Pressure Procedure: The following procedure shall be used to calculate the failure pressure for each corroded area with a wall loss greater than 20%. Other analytical techniques, such as linear elastic fracture mechanics, may be used as deemed appropriate with approval of the Manager of System Integrity or his designate.

Documentation: Form I, "REMAINING STRENGTH EVALUATION," or similar documentation shall be completed with the pertinent background data including pipe geometry, pipe material properties, and corrosion mapping data (Form H, page 4 of 10 and page 5 of 10). The RSTRENG analysis results shall also be documented on this form. The interaction rules for corrosion defects should be 1 inch axially or 6t circumferentially. Other technically supported methods may also be used.

Predicted Burst Pressure (*Pf*): The predicted pressure shall be calculated for each corroded area with a wall loss greater than 20% using the RSTRENG or equivalent (i.e., ASME B31G, Modified B31G) calculation methodology.

> **Analyst: The area PLE shall be notified. It is the PLE's responsibility to ensure repair requirements are determined and implemented, if required, and that the remaining strength is calculated and documented before the pipe is recoated and the bell hole is backfilled.** An individual qualified to use RSTRENG or an equivalent calculation methodology shall make these calculations. The qualification records shall be maintained in the Integrity Management Program file. The DE Inspection personnel are responsible for collecting the calculation information.

Determination of Safety Factor: The safety factor of the evaluated area shall be determined that it meets the minimum safety factor required by the class location.

Calculation: The safety factor shall be determined by:

$$SF_{corr} = \frac{Pf}{MAOP}$$

SF_{corr} = *Safety factor of corroded area*

MAOP = Maximum allowable operating pressure

Pf = Predicted Burst Pressure

Comparison to Class Design Requirements: The safety factor shall be compared with the safety factor for the class location of the evaluated area (SF_{DR}). Table 5.7.2 provides the corresponding safety factor for each class location.

TABLE 5.7.2 DESIGN REQUIREMENTS BY AREA CLASS LOCATION

Area Class	% SMYS	SF_{DR}
1	0.72	1.39
2	0.6	1.67*
3	0.5	2.00
4	0.4	2.50*

*Note: This table is more conservative than ASME B31.8S

5.7.3 **Response:** If SF_{corr} is less than SF_{DR} specified in Table 5.7.2 for the given class location it will require a repair. If the anomaly meets the requirements for an immediate repair as stated below then the pressure in the pipeline shall be reduced and the pipeline shall be repaired.

5.7.4 **Immediate Repair Condition**: Section O of DOT 49 CFR 192 refers to the requirement for scheduling responses relative to immediate, schedule, or monitored condition. With ECDA the condition is discovered during the direct examination of a specific point on the pipeline as required by the PE after the indirect inspection data has been collected and analyzed. Because of this, any indication found at the time of the direct examination that meets the definitions of Immediate, Schedule or Monitor indications as described in Section O of DOT 49 CFR 192 shall be promptly remediated by repair or removal per UO4134 or DOT 49CFR 192.933 whichever is more stringent. To maintain safety, the operating pressure of the pipeline shall be temporarily reduced or shut down if any of the following conditions are met:

Immediate Condition

A calculation of the remaining strength of the pipe shows P_f less than or equal to 1.1 times the Maximum Allowable Operating Pressure at the location of the anomaly.

A dent that has any indication of metal loss, cracking or a stress riser.

All indications of stress corrosion cracks; [ASME B31.8S-2001, Section 7.2.2].

Metal-loss indications affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding.

Smooth dent located between the 8 and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter; [§192.933(d)(2)].

A dent with a depth greater than 2% of the pipeline's diameter, that affects pipe curvature at a girth weld or at a longitudinal seam weld. [§192.933(d)(2)].

Any indications that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline.

An indication or anomaly that in the judgment of the qualified person evaluating the assessment results requires immediate action (Ref. for above 49 CFR 192.933 (d) – (i-iii).

Schedule Condition

It may be necessary to reduce the pressure in the pipeline to address Schedule Conditions. The reduction in pressure should be reduced if required by UO4134 to evaluate the condition or if the PLE or PE require it. Also, the determination of any remediation for the following conditions shall be conducted per UO4134:

Any indication on a pipeline operating at or above 30% SMYS of a plain dent that exceeds 6% of the nominal pipe diameter.

Mechanical damage with or without concurrent visible indentation of the pipe.

Dents with cracks.

Dent that effect ductile girth or seam welds if the depth is in excess of 2% of the nominal pipe diameter.

Dents of any depth that affect non-ductile welds.

A smooth dent between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe size (NPS)12 inches).

Monitor Condition

Although it may not be necessary to reduce pressure to remediate a Monitor Condition the PLE or PE shall evaluate the following conditions and determine if pressure in the pipeline needs to be reduced or that a repair needs to be made per UO4134. The following conditions would meet the definition of a monitor indication:

A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12 inches) located between the 4 o'clock and the 8 o'clock position (bottom 1/3 of the pipe).

A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12 inches, and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12 inches) that affects pipe curvature at a girth weld or seam weld demonstrate critical strain levels are not exceeded.

These analyses must consider weld properties.

5.7.5 **Determining Reduction in Pressure:** If it is determined that the pressure shall be reduced, then temporary reduction in pressure shall be reduced using ASME/ANSI B31G or "RSTRENG" or reduce operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. A reduction in operating pressure cannot exceed 365 days without notifying the CPUC and OPS and providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline (Ref. 49CFR 192.933 (a)). Remediation activities that have not been completed in accordance with DOT 49CFR 192.933 timeframes, and a temporary pressure reduction to the pipeline has not been taken in order to provide additional safety to the public shall be reported to the CPUC and OPS in accordance with the requirements of DOT 49 CFR Part 192.933(c).

5.7.6 Remediation: The PM shall work with the Pipeline Engineer to have the damage per UO4134 remediated in order to restore the pipe to the MAOP with the appropriate safety factor specified in Table 5.7.2 or reduce MAOP to establish the safety factor. NOTE: Any remediation activities taken shall be sufficient to ensure that the anomaly is unlikely to threaten the integrity of the pipeline before the next scheduled reassessment. [ref DOT 49CFR 92.933(a)]

5.7.7 Notification: If any of the above conditions are met the following people shall be aware and/or contacted:

- Responsible Pipeline Engineer
- Supervising Engineer of TIMP
- Manager of Integrity Management
- Manager of Pipeline Engineering
- Director of Integrity Management

The PM shall ensure that all required operational/pressure changes are communicated to Gas System Operations (GSO) and that all required operational/pressure changes are documented on Form I.

5.8 Root Cause Analysis

5.8.1 Procedure: The PM shall assure that a root cause analysis is performed for each area of corrosion greater than 20% wall loss found during any of the direct examinations.

5.8.2 Objective: The analysis is to determine the likely causes for the corrosion and determine the following:

- Is the ECDA process suitable for finding degradation caused by the identified mechanism?
- The likelihood that it will occur elsewhere in the ECDA region.
- Determine if the corrosion is active or inactive.

Identify mitigative measures to eliminate future continued corrosion of the same type.

5.8.3 Analysis Content: The analysis should discuss the following aspects:

5.8.3.1 Coating Failure: The extent and reason for the coating failure. Discussion if the failure is localized or widespread.

5.8.3.2 Cathodic Protection Ineffectiveness: Why the CP was ineffective in this area. Include discussion of history of CP in the area. The expected presence and reasons for shielding of CP current or the presence of stray currents.

5.8.3.3 Corrosion Mechanism: Identify the main drivers for corrosion in the area including soil chemistry and physical properties, such as chlorides, sulfates, sulfides, total organic carbon (TOC), pH, moisture, corrosive microbes, rock shielding, etc. Is the corrosion active or inactive?

5.8.3.4 **Degradation in other areas:** Discuss the likelihood and location of where similar characteristics and where similar corrosion may be occurring.

5.8.3.5 **Mitigative Measures:** Identify potential mitigative measures to arrest corrosion at the particular location and at all other similar locations on the pipe.

5.8.3.6 **ECDA Feasibility:** Discuss the suitability of the ECDA process on identifying similar areas of degradation.

5.8.4 **Documentation:** The root cause of the external corrosion for each Immediate or Scheduled indication excavated shall be documented and placed in the project file and summarized on Form I "REMAINING STRENGTH EVALUATION AND ROOT CAUSE ANALYSIS." A root cause analysis can cover multiple indications provided that they are similar in all the characteristics listed in paragraph 5.8.3.

5.8.5 **ECDA Evaluation:** If the root cause analysis identifies a degradation mechanism that the ECDA process is not well suited to detect, then it shall be documented in the analysis and on Form I. Per RMP-06 a suitable assessment method shall then be used to evaluate the subject segments of pipe for that degradation mechanism.

5.8.6 **Corrective Action:** If corrective action was taken to address the root cause during the assessment, then it shall be documented on Form I.

5.9 In Process Evaluation

5.9.1 Once the direct examinations root cause analyses and remaining strength evaluations are completed, an evaluation to critically assess the original criteria used to prioritize indications and classify indications shall be performed.

5.9.2 If corrosion activity is less severe than classified, the criteria may be adjusted to redefine the severity of the indications. In addition, the prioritization criteria may also be adjusted.

5.9.3 If corrosion activity is worse than originally classified or prioritized, the operator shall adjust the criteria used for the indications. In addition, consideration should be given to performing additional indirect inspections to gain further insight and indication resolution.

5.9.4 If the classification or prioritization criteria is modified, at least one additional direct examination must be performed in each region in the highest priority areas to validate the new criterion.

5.10 Reclassification and Reprioritization of Indications

5.10.1 **Overview:** Figure 4.8 shows the method of reprioritization of indications. The additional data collected from the direct examination and the resulting analyses shall be used to evaluate the appropriateness of the initial assigned priority of indications. This evaluation may result in indications being raised or lowered in priority as well as be classified as non-reportable indications.

The reprioritization process involves;

- determining the actual condition of the pipe, in terms of remaining strength and calculated safety factor
- assigning it a priority (immediate, scheduled, monitored) base on its actual condition, or remaining strength.

This data is then used to reprioritize the remainder of the indirect inspection indications that have not been excavated.

5.10.2 Reprioritization Criteria: The following describes how actual pipe conditions are prioritized and how this data is used to reprioritize the remaining indirect examination indications. Table 5.11 summarizes the requirements of reprioritization. SF_{corr} is the safety factor determined in 5.8.2. SF_{DR} is the safety factor for the respective class location that are given in Table 5.8.2.

5.10.2.1 Immediate: Indications in this category have a SF_{corr} less than 1.1.

5.10.2.1.1 Additional Requirement: If any Immediate indications in an ECDA region are validated from direct examinations to meet the criteria in Table 5.10, then all remaining immediate indication footage of the specific indication must be directly examined, smart pigged, or hydro tested.

5.10.2.2 Scheduled: Indications in this category have a SF_{corr} of greater than SF_{DR} and have evidence of inactive or active corrosion greater than 20% wall loss.

5.10.2.3 Monitored: Indications in this category have no sign of active or inactive corrosion greater than 20% wall loss.

5.10.2.4 No Indications (NI): Indications in this category have no sign of active or inactive corrosion and meet a code compliance criteria.

TABLE 5.10 REPRIORITIZATION CRITERIA BY AREA CLASS

Area Class	SF_{corr} Requirements for Priority Categories			
	Immediate	Schedule	Monitored	NI
1	<1.39	>1.39 w/corrosion > 20% wt	No corrosion > 20% wt	No corrosion w/850 "on" or 100mV shift
2	<1.67	>1.67 w/corrosion > 20% wt	No corrosion > 20% wt	No corrosion w/850 "on" or 100mV shift
3	<2.00	>2.00 w/corrosion > 20% wt	No corrosion > 20% wt	No corrosion w/850 "on" or 100mV shift
4	<2.5	>2.5 w/corrosion > 20% wt	No corrosion > 20% wt	No corrosion w/850 "on" or 100mV shift

5.10.3 Reprioritization Process: Complete Form J, REPRIORITIZATION, for all indications that are direct examined in the following two steps:

Prioritization Evaluation: Complete the upper portion of the form with the appropriate information. Document what priorities need to be reprioritized.

Reprioritization Indications: From the prioritization evaluation data reprioritize all indications as appropriate. Document the reprioritization on the lower half of Form J.

5.10.4 Reprioritization Requirements: The following requirements or allowances shall be applied to the reprioritization of indications.

Reprioritization is required if the above methodologies shows that the corroded area is worse than its assigned Priority.

When an indication's priority is raised the PE shall re-evaluate other indications that may have similar root cause conditions in the ECDA region.

If remediation is performed on a portion of an Immediate indication, (e.g., 10 feet has been exposed and directly examined), then it may be moved to a lower priority provided:

- No corrosion meeting the Immediate criteria in Table 5.10 is found
- Adequate CP has been restored

If remediation is performed on a Scheduled indication then it may be moved to Monitored, if no corrosion is found and may be further reduced to an NI, provided it can meet the cathodic protection criteria.

6.0 POST ASSESSMENT

6.1 **Purpose:** The purpose of the Post Assessment step is to determine the remaining life and reassessment intervals for an ECDA Region, evaluate the overall effectiveness of the ECDA process, and recommend short and long term mitigation items.

6.2 **Remaining Life Determination:** This procedure calculates the remaining life of a corroded area based on the given length of time at an assumed corrosion rate that a corroded area thins to the predicted burst pressure divided by SF_{DR}.

$$RL \propto f\left(\frac{Pf}{SF_{DR}}\right)$$

6.2.1 **Corroded Area Dimensions:** The most severe (lowest remaining strength and lowest safety factor) condition found in each ECDA Region shall be used in determining remaining life.

6.2.1.1 **Root Cause Exception:** If the root cause analysis determined that the corroded area is unique then the next smaller size corroded area may be used. If this occurs, the PE must document this decision on Form K.

6.2.2 **Corrosion Rate:** Methods based on the data developed may be used for corrosion rate estimates. (Ref. NACE RP 0502-2002 D3.1)

6.2.2.1 When other data are not available, a pitting rate of 0.4 mm/y (16 mpy) is recommended for determining re-inspection intervals. This rate represents the upper 80% confidence level of maximum pitting rates for long-term (up to 17-year duration) underground corrosion tests of bare steel pipe coupons without CP in a variety of soils including native and non-native backfill. (Ref NACE RP0502-2002 D3.2)

6.2.2.2 The corrosion rate in Paragraph 6.2.2.1 may be reduced by a maximum of 24% provided it can be demonstrated that the CP level of all pipelines or segments being evaluated have had at least 40 mV of polarization for a significant fraction of the time since installation. (Ref NACE RP0502-2002 D3.3)

6.2.2.3 **Exceptions:** ASME B31.8S (2001) page 63, Table B1, shows average corrosion rates related to soil resistivity which are provided in Table 6.2.1. Other corrosion rates that are scientifically supported may also be used. The Manager of CE&DA shall approve using these rates:

TABLE 6.2.1 CORROSION RATES VS. SOIL RESISTIVITY

Corrosion Rate (mpy)	Soil Resistivity (ohm-cm)
3	>15,000+no active corrosion
6	1,000 – 15,000 and/or active corrosion
12	<1,000 (worst case)

6.2.3 Predicted Burst Pressure: The P_f used in this methodology shall be the "Predicted Burst Pressure" calculated in RSTRENG or equivalent.

6.2.4 Remaining Life Determination: The equation below shall be used to calculate the remaining life:

$$RL = \frac{0.85}{YP}[Pf - MAOP]\frac{t}{CR}$$

where:

RL = Remaining Life (years)

YP = *Yield Pressure (psi)*

Pf = Burst Pressure by RSTRENG or equivalent (psi)

$MAOP$ = Maximum Allowable Operating Pressure (psi)

t = Un-corroded Actual Wall Thickness (in)

CR = Corrosion Rate (inches/year)

6.2.4.1 Documentation: The remaining life shall be documented on Form K.

6.3 Reassessment Intervals

6.3.1 Remaining Life: The reassessment interval shall not exceed half of the remaining life calculated in 6.2.4.

6.3.2 Maximum Reassessment Interval: When corrosion defects are found during the direct examinations, the maximum reassessment interval for each ECDA region shall be taken as one half the calculated remaining life. For additional requirements on maximum intervals see Appendix G (Ref ASME B31.8S Table 3). (Note: Confirmatory Assessment (CA) is required in 7 years.)

6.3.3 Documentation: The reassessment interval for each region per NSeg shall be recorded on Form K and signed by the PE, Project Manager, DA Program Manager, and the Manager of CE&DA.

SAMPLE REPRIORITIZATION, REMAINING LIFE AND REASSESSMENT INTERVAL CALCULATIONS

Example 1) Determine the actual priority and the remaining life according to NACE RP – 0502-2002. Also, determine the reassessment interval per NACE and also according to ASME B-31.8S. Apply to the following data set:

Site 1: The original IIT priority was "Scheduled." This site is in a class 3 location in region 2 and direct examination showed that the maximum corrosion was 3% of the depth. The RSTRENG failure pressure (P_f) is1830 psig. The pipe data is:

- Class location 3
- MAOP 400 psig
- Wall thickness 0.312
- 24-inch diameter
- Grade X-60

Solution:
The actual priority of the indication should be determined first. Accordingly, determine the SF_{corr} (P_f/MAOP) and the SF_{dr} (code design requirements):
- SF_{corr} = 1830/400=4.55
- SF_{dr} = 2.0

From this use Table 5.10 to determine the actual prioritization. This table uses the actual burst pressure (Pf) with the level of polarization to determine the actual priority. The actual numbers used in the table are based on the minimum code design factors plus some additional margin ranging from 7% to 13% of the code design factor. Based on the location being a class 3 location, and that there was no corrosion greater than 20% of the wall thickness, the actual priority is reduced to "Monitored." Note that all indications that are directly examined must go through the reprioritization process. Once this has been done, then the entire region may be collectively reprioritized to the highest level represented (most conservative level) of the entire data set.

The next step is to compute the remaining life according the NACE formula below:

$$RL = \frac{0.85}{YP}\left[Pf - MAOP\right]\frac{t}{CR}$$ where:

RL = Remaining Life (years)

YP = Yield Pressure (psi)

Pf = Burst Pressure by RSTRENG (psi)

SF_{DR} = Design Requirement Safety Factor (Table 5.7.2)

MAOP = Maximum Allowable Operating Pressure (psi)

t = Uncorroded Actual Wall Thickness (inch)
CR = Corrosion Rate (inches/years) (from Table 6.2.1 or by direct measurement using LPR coupons, etc.)

The first input should be to calculate the yield pressure:

Yield Pressure (YP) = $\frac{2St}{D}$

Where S is the material grade, t the thickness, and D is the diameter.

$$YP = \frac{2(60{,}000)lbs(0.312)inch}{(inch)(inch)(24 - inch)} = 1560 \text{ psi}$$

The corrosion rate is determined from the measured soil resistivity (H-form) data using Table 6.2.1 or by direct corrosion rate measurement. For this example the soil resistivity was measured to be 6400 ohm-cm. Therefore the equivalent corrosion rate is 6 mpy. Now that all the variables for the remaining life equation have been determined, simply plug in the appropriate values.

$$RL = \frac{0.85}{YP}\left[Pf - MAOP\right]\frac{t}{CR} = \frac{0.85}{1560}\left[1820 - 400\right]\frac{0.312}{0.006} = 40.23 \text{ years}$$

Application of the NACE RP 0502 –2002 half life requirement makes the reassessment interval 20.11 years. Additionally, the ASME B31.8S Code limits the reassessment interval to 10 years maximum. Therefore the reassessment interval for this site cannot exceed 10 years.

Example 2) Determine the actual priority and the remaining life according To NACE RP – 0502-2002. Also determine the reassessment interval per NACE and then B-31.8S. The data set:

Site 2. The original IIT priority was "Scheduled." This site is in a class 3 location in region 1 (Coated pipe less Region 2), and direct examination showed that the maximum corrosion was17% of the depth. The RSTRENG failure pressure (P_f) is2692 psig. The pipe data is:

- Class location 3
- MAOP 650 psig
- Specified wall thickness 0.188". Actual wall thickness in area adjacent to corrosion damage 0.228".
- 6-inch diameter (6.625" actual OD)
- Grade B (35 ksi SMYS)
- P/S = - 998 mV

Calculations needed to determine the actual priority:

$SF_{corr} = P_f/MAOP = 2692/650 = 4.14$
$SF_{dr} = 2.0$

Reprioritization is accomplished using the criteria in Table 5.10. Accordingly, the actual priority is determined to be "Monitored."

The next step is to compute the remaining life according the NACE formula below:

$$RL = \frac{0.85}{YP}\left[Pf - MAOP\right]\frac{t}{CR} \quad \text{where:}$$

RL = Remaining Life (years)

YP = Yield Pressure (psi)

Pf = Burst Pressure by RSTRENG (psi)

SF_{DR} = Design Requirement Safety Factor (Table 5.7.2)

$MAOP$ = Maximum Allowable Operating Pressure (psi)

t = Thickness (inch)
CR = Corrosion Rate (inches/years) (from Table 6.2.1 or by direct measurement using LPR coupons, etc)

The yield pressure calculation is:

$$\text{Yield Pressure (YP)} = \frac{2St}{D}$$

Where S is the material grade, t the thickness, and D is the diameter.

$$\text{YP} = \frac{2(35{,}000)lbs(0.228)inch}{(inch)(inch)(6.625 - inch)} = 2409 \text{ psi}$$

The corrosion rate is 3 mpy based on a measured soil resistivity of 35,150 ohm-cm. Therefore the remaining life is

$$RL = \frac{0.85}{YP}\left[Pf - MAOP\right]\frac{t}{CR} = \frac{0.85}{2409}\left[2692 - 650\right]\frac{0.228}{0.003} = 54.76 \text{ years}$$

The half life requirement makes the calculated reassessment interval 27.38 years. The B-31.8S requirements limit it to 10 years. Therefore the reassessment interval may not exceed 10 years.

6.4 **ECDA Performance Report:** The PM shall complete the ECDA Performance Report, Form L. The report shall be filed in the ECDA project file as well as the Integrity Management Program file under "Performance Measures." In addition, re-classifications and severity of corrosion shall be tracked on a programmatic level to assess overall ECDA performance and be used, as appropriate, to enhance the prioritization/categorization of indications. In addition, root cause analysis of leaks in HCA's that were previously assessed with ECDA, shall be performed to determine if there are gaps or improvements to the ECDA process that would have identified the location before it leaked.

6.5 **Project Report:** The PM shall work with a representative of the TIMP team to prepare a project report and submit it for approval to the manager of Integrity Management

6.5.1 Contents: The report shall contain a cover letter (Executive Summary) which summarizes any mitigation requirements and associated suggested timetables and the following information:

Compliance Documentation Section

- Form A: Data Element Check Sheet
- Form B: Sufficient Data Analysis
- Form C: Feasibility Analysis Report
- Form D: Indirect Inspection Tool Report
- Form E: ECDA Region Report
- Form F: IIT Procedure Review Form
- Form I: Remaining Strength Evaluation and Root Cause Analysis
- Form J: Reprioritization Reports
- Form K: Remaining Life Determination
- Form L: ECDA Performance Reports
- Form M: Exceptions Reports

Indirect Inspection Data Section

- Form G: Indication Classification and Direct Examination
- Form O: Indirect Inspection Field Meet

Direct Examination Maps Section

- Form N: Dig Sheet

Direct Examination Data Section

- Form H: Data Excavation Sheets

Note: If threats other than external corrosion were identified during the assessment phase, then the PE shall detail those threats in this report.

6.5.2 Documentation: After the Manager of Integrity Management approves the report it shall be distributed as appropriate and filed in the ECDA project file.

6.5.3 Communication of recommended mitigation plan: The PM shall communicate mitigation tasks that pertain to the pipeline being assessed. . For example, a meeting should be held to discuss what types of mitigation are recommended to improve pipeline integrity such as pipeline replacement, recoating, installation of additional monitoring points, upgrade of CP system, etc. The following responsible parties should be included in this meeting:

- Responsible Pipeline Engineer
- T&R Supervisor or District Superintendent
- Responsible Senior Gas Distribution Engineer
- Project Engineer
- DA Project Manager

APPENDIX A

ECDA Forms

- A representative from Corrosion Engineering.

6.5.3.1 This shall include Executive Summary, mitigation plans and coupon locations (aerial maps). Reference to any location must be identified with NAD83 UTM Zone 10 North (Northing and Easting) or Longitude/Latitude and land base reference (i.e. Main Street with distance to nearest intersecting street name).

7.0 EXCEPTION PROCESS

7.1 Expectations: It is expected that all requirements of this procedure be met in conducting an ECDA. However, when this is not possible, then exceptions can be made by obtaining approval, and documenting the exceptions, as prescribed in this section.

7.1.1 Note: If it is the intent to take exception to a "shall" stated in either the DOT Integrity Management Rule or the NACE RP0502-2002 Recommended Practice for ECDA, then a waiver must be obtained from OPS.

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

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

7.3.1 Section of Procedure: State the specific paragraph number where the exception is being taken. Briefly state in your own words the requirements of the paragraph.

7.3.2 Alternative Plan: State what is proposed instead of what is required in the procedure.

7.3.3 Reason: Provide the reason the exception is needed.

7.3.4 Recommendation: Indicate if it is recommended to change the procedure or that this exception is project specific.

7.3.5 Approval: Obtain approval from the Manager of System Integrity or his designate prior to acting on the exception.

7.3.6 Documentation: Document the above steps on Form M, EXCEPTION REPORT. Place all exception reports in the project file.

DA FORM A: DATA ELEMENT CHECK SHEET

DATE: ____________________

STARTING MILE POINT: ____________________

ENDING MILE POINT: ____________________

N-SEGMENT NUMBER: ____________________

ROUTE NUMBER: ____________________

PM: ____________________

		Requirements				Data Location						
ID #	Data Element Description	Need[1]	InspectionTool[2]	Region Selection[2]	Interpretation Analysis[2]	GIS	As-built Job file	Field	Districts or Division	Other	Sign Off	Comments
1.0 Pipe Related												
1.1	Material and Grade	R	C	C	R	X	X					
1.2	Diameter	R	C	N/R	R	X	X					
1.3	Wall thickness	R	N/R	N/R	R	X	X					
1.4	Year manufactured	C	N/R	N/R	R							
1.5	Seam Type	R	N/R	C	C	X	X					
1.6	Bare pipe	R	R	R	R	X	X					
1.7	Pipe Manufacturer	C	N/R	N/R	C	X	X		X	As-Builts		
2.0 Construction Related												
2.1	Year installed	R	N/R	N/R	R	X	X					
2.2	Recent route changes/ modifications that may not be in GIS	D	N/R	C	N/R			X	X	As-builts		
2.3	Construction practices	D	C	C	C		X			Engr. Stds. drawings		
2.4	Location of major pipe appurtenances such as valves, taps, tie-in locations and angle points.	D	N/R	C	C	X	X	X				
2.5	Locations of casings (including gelled casings)	R	R	R	C	X	X			Trans. Plat sheets, CPA Records		
2.6	Location of spans	R	R	R	C	X	X	X	X			

[1, 2] R = Required, D = Desired (See paragraph 2.5 for definitions)

[2] R = Required, C = Considered

2.7	Location of bends, including miter bends and wrinkle bends	D	C	C	C		X			Trans. Plat Sheet		
2.8	Depth of cover	D	C	C	C			X	X			
2.9	Underwater sections and river crossings	R	R	R	C	X	X	X				
2.10	Locations of river weight and anchors	D	C	C	C		X	X		As builts		
2.11	Proximity to other pipelines structures, transmission lines and electrified DC rail crossing	D	C	C	C	X		X				
2.12	Proximity to HV electric transmission structures	D	C	C	C	X		X				
2.13	Location of reinforced concrete caps	R	N/R	N/R	N/R		X		X	Pipeline engineer		
3.0 Soil Environmental												
3.1	Soil characteristics & types. Refer to Appendix B and D	D	C	C	C	X		X				
3.2	Drainage	D	N/R	C	N/R			X				
3.3	Topography	D	C	C	N/R			X				
3.4	Land use (current/past)	R	C	C	N/R	X		X				
3.5	Frozen ground	R	C	N/R	N/R			X				
3.6	Assessment of environmental conditions	D	N/R	N/R	C	X		X	X			See E-Screen Modified Appendix I
4.0 External Corrosion (EC) Control												
4.1	CP system type (anodes, rectifiers and locations)	R	C	C	C			X		CPA Records		
4.2	CP System Boundaries	R	C	C	C			X	X	CPA Records/Preassessment Interview		
4.3	Locations Of Isolation Points	R	C	C	C			X	X	CPA Records/Preassessment Interview		
4.4	Locations Of Connections to Distribution	R	C	C	C			X	X	CPA Records/Preassessment Interview		
45	Stray Current sources/locations	D	N/R	C	C	X		X	X	CPA Records. Past survey reports		
4.6	Test point locations (pipe access points)	R	N/R	C	N/R	X		X		CPA Records		
4.7	CP evaluation criteria	R	N/R	C	C					CPA Records, Paradigm		

4.8	CP maintenance history	R	N/R	C	C					CPA Records, Paradigm		
4.9	Years without CP applied	D	N/R	C	N/R		X					
4.10	Coating type-pipe	R	R	C	C	X	X					
4.11	Coating condition	D	C	C	N/R	X			X	Direct Assessment		
4.12	Current demand	D	N/R	N/R	C					CPA Records		
4.13	CP survey data/history	D	N/R	C	C					CPA Records Paradigm	4.13	CP survey data/history
4.14	Other prior integrity related activities – CIS, ILI runs, etc.	R	C	N/R	C	X				Corrosion Group, IMP Library		
5.0 Operational Data												
5.1	Pipe operating temperature	D	N/R	C	C					Field measurements		
5.2	Operating stress level	R	N/R	N/R	R	X						
5.3	Monitoring programs (Coupon, patrol leak surveys etc.)	D	N/R	C	N/R					Corrosion Group		
5.4	Pipe inspection reports-excavation	R	N/R	C	N/R	X						
5.5	Repair history/records, steel/composite repair sleeves, repair locations	R	C	C	C	X			X	Form A's		
5.6	Leak rupture history (EC)	R	N/R	C	N/R	X	X					
5.7	Evidence of external MIC	D	N/R	N/R	C					Corrosion records		
5.8	Type and frequency of third party damage	R	N/R	C	N/R	X						
5.9	Data from previous over the ground surveys	R	N/R	C	N/R	X						
5.10	Pressure Test. Dates / Pressure	D	N/R	C	C	X						
5.11	Other prior integrity related activities – CIS, ILI runs, etc.	R	C	N/R	C	X				Corrosion Group		
6.0 Internal Corrosion (IC) Threat Assessment												
6.1	History of IC leaks	D	C	D	C	X		X	X			Pipe inspection form
6.2	Topography	D	D	D	D	X		X				
6.3	Depth Survey	D	D	N/R	D	X		X				
6.4	Received gas from gathering or storage lines	D	N/R	D	D	X		X				

6.5	Drip Location	D	N/R	C	C	X		X				Check drip logs, PLM
6.6	Corrosometer Probe reads	D	D	C	D	X		X				
6.7	Corrosion inhibitor solubility, carrier, dose rate, years of treatment, monitoring, detection of inhibitor in downstream liquids.	R	R	C	C	X		X	X			
6.8	History Of Liquids	R	C	C	C			X	X	Drip Logs in Division/District		
6.9	Chemical/Microbial analysis of liquid samples	D	D	C	D	X		X	X			
6.10	Acid Gas Partial Pressures	C	C	C	C							District or Corrosion Group
6.11	Line Pressure and Flow Rate(Including fluctuactions in pressure and direction)	D	D	C	D	X		X	X			
6.12	Dew Point & Temp	D	D	C	D	X		X	X			
6.13	Previously "pigged"	D	D	C	D	X		X	X			
6.14	Type and locations of current and historic inlets and outlets, tie-ins, taps, insulating joints, drains, drips, cast iron components.	R	R	R	R							
6.15	Type of dehydration	R	R	N/R	C							
6.16	Data on liquid upsets	D	C	C	C							
6.17	Corrosion monitoring (LPR probes, weight loss coupons, etc.)	R	R	N/R	C							
6.18	Type of flow coating	C	N/R	N/R	C		X		X	As-builts		
7.0 Stress Corrosion Cracking (high ph SCC) Threat Assessment												
7.1	Year of Manufacture	D	C	C	C	X						
7.2	Operating Stress Level	D	C	C	C	X						
7.3	Operating Temp	D	C	C	C	X						
7.4	Distance from Compressor station	D	C	C	C	X						
7.5	Coating type	D	C	C	C	X						

7.6	Pressure Test. Dates / Pressure	D										
8.0 Third Party Threat												
8.1	Review Easement documents for foreign crossings	C	C	C	C							Land Department
8.2	Evidence of new excavation or construction	C	C	C	C							
8.3	Historical concentration of USA tags	C	C	C	C	X						
8.4	Known areas of shallow cover	C	C	C	C	X						Interview Questions, see Appendix F for details
8.5	Pipe inspection reports/repairs	C	C	C	C	X						Interview Questions, see Appendix F for details
8.6	Patrol Records	C	C	C	C	X						Interview Questions, see Appendix F for details
9.0 Hard Spot Threat												
9.1	Threat of Hard Spots	C	C	C	C							Information provided by Risk Management Department
10.0 Casings												
10.1	Year Installed	D	D	X	C	X	X					
10.2	Type of casing	D	D	X	D		X					
10.3	Type of end seal	D	N/R	X	D		X					
10.4	Spacer	D	N/R	X	D		X					
10.5	Coated	D	N/R	X	D		X					
10.6	Gelled casings	D	D	X	R	X		X	X			
10.7	History of shorts	D	N/R	X	R			X	X			
10.8	Presence of vents	D	R	X	R	X	X	X	X			
10.9	Presence of ETS	D	R	X	R	X	X	X	X			
10.10	Water table	D	N/R	X	D	X		X	X			
10.11	Type of soil	D	N/R	X	D	X		X	X			
10.12	Proximity to compressors station	R	N/R	X	R	X		X	X			
11.0 SPANS												
11.1	Location Of Spans	R	R	R	C	X		X	X	Span Listing in Districts/Divisions		
11.2	Span Accessibility	D	N/R	N/A	C			X	X			

DA Form B: Sufficient Data List

DATE:__________________________________
STARTING MILE POINT:__________________________
ENDING MILE POINT:___________________________

N-SEGMENT.__________________________________
ROUTE NUMBER:_______________________________
PM:_______________________________________

SUFFICIENT DATA ANALYSIS

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

Sufficient Data: Yes ______ No ______

Project Manager: ______________________ **Date:** ________________

PE or Designate: ______________________ **Date:** ________________

Proprietary Information

DA Form C: **Feasibility Analysis Report**

DATE: ____________________

STARTING MILE POINT: ____________________

ENDING MILE POINT: ____________________

N-SEGMENT ____________________

ROUTE NUMBER: ____________________

PM: ____________________

Instructions: Analyze each data category to answer the general questions listed under each ECDA step in the table below. In answering the question include the following:

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

ECDA FEASIBILITY ANALYSIS

ID #	Data Categories	**Indirect Inspection** Can existing indirect inspection tools be applied to the GIS pipe segments identified in the ECDA project and be expected to provide meaningful results on potential locations where the coating is damaged? If any of the conditions listed in paragraph 3.7.2 is present an explanation shall be provided here why ECDA is feasible for the subject GIS pipe segments.	**Direct Assessment** Is it physically and economically feasible to gain access to the pipeline to conduct direct assessment and be expected to gain meaningful data?	**Post Assessment** Can it be reasonably expected to be able to determine reassessment intervals of the GIS pipe segments given the existing data?
1.0	Pipe Related			
2.0	Construction Related			
3.0	Soils/Environmental			
4.0	Corrosion Control			
5.0	Operational Data			
8.0	Third Party Damage			
10.0	Casings			
11.0	Spans			

ECDA Feasible: Yes_____ No_____

Project Manager: ____________________ **Date:** ____________________

PE or Designate: ____________________ **Date:** ____________________

DA Form D: Indirect Inspection Tool Selection

DATE: ____________________
STARTING MILE POINT: ____________________
ENDING MILE POINT: ____________________
Note: The following table is maintained in electronic format.

N-SEGMENT: ____________________
ROUTE NUMBER: ____________________
PM: ____________________

Program	Division	Nseg	Gas Map ID	Route	Pipe Segment Number	ECDA MP Start	ECDA MP Stop	Boundary Marking Type	Footage	1st IIT	2nd IIT	3rd IIT	ECDA Region Number (Form E)	Coating Type (*=assumed coating)	Comments	Vent Pipe Fnd?	ETS Fnd?

PE or Designate: ____________________ **Date:** ____________________

Project Manager: ____________________ **Date:** ____________________

Proprietary Information

DA Form E: ECDA Region Report

DATE:________________________
STARTING MILE POINT:____________________
ENDING MILE POINT:____________________

N-SEGMENT NUMBER:____________________
ROUTE NUMBER:____________________
PM:____________________

Instructions: For each ECDA region record the two IIT's for that region and the unique data element(s) that are used to establish the region. The Indirect inspection methods and at least one other characteristic must be recorded for each region. Bare pipe, casings, and water crossing require separate ECDA regions (Table 3.3.1).

ECDA REGION DESCRIPTIONS

ECDA Region	Pipe Related Characteristics (include Data Element #)	Construction Related Characteristics (include Data Element #)	Soils and Environmental Characteristics (include Data Element #)	Corrosion Control Characteristics (include Data Element #)	Operational Data Characteristics (include Data Element #)

PE or Designate: ____________________ Date: ____________

Project Manager: ____________________ Date: ____________

Manager of Integrity Management: ____________________ Date: ____________

DA Form F: IIT Procedure Review Form

DATE: ____________________
REVIEWER: ____________________
VENDOR CONTACT: ____________________

IIT METHOD: ____________________
VENDOR: ____________________
VENDOR PROCEDURE NUMBER: ____________________

INSTRUCTIONS: Paragraph 4.3.1 in the ECDA Procedure provides instructions on completing and filing of this form

Procedure Content Review

Acceptable	Not Acceptable		Comments
☐	☐	Procedure Number	
☐	☐	General Description	
☐	☐	Limitations	
☐	☐	Procedure Qualification	
☐	☐	Safety	
☐	☐	Instrumentation	
☐	☐	Personnel Qualifications	
☐	☐	Calibration	
☐	☐	Equipment Connections	
☐	☐	Pipe Locator	
☐	☐	Measurements	
☐	☐	Special Diagnostics	
☐	☐	Distance Measurements	
☐	☐	Data Recording	
☐	☐	Approval	

General Comments: ____________________

Approved	Not Approved	
☐	☐	Comment: ____________________

PE or Designate: ____________________

Date: ____________________

DA Form G: DIRECT ASSESSMENT PRIORITIZATION ANALYSIS

DATE:____________________
STARTING MILE POINT:____________________
ENDING MILE POINT:____________________

N-SEGMENT NUMBER:____________________
ROUTE NUMBER:____________________
PM:____________________

Pipeline Section	Start MP	End MP	Item #	Station Begin	Station End	Footage (Feet)	CIS Category	PCM Category	DCVG Category	ECDA Category	ECDA Region	Comments	Depth of Cover (in)	Pipe Gradient (deg)	NORTHING BEGIN	EASTING BEGIN	NORTHING END	EASTING END

FORM H: DIRECT EXAMINATION DATA SHEET 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 ☐ NI ☐ EFFECTIVENESS

EXCAVATION REASON:
☐ ECDA ☐ ILI ☐ RECOAT
☐ ICDA ☐ OTHER ____

IF PRACTICAL, TAKE P/S OR CIS READS BEFORE EXCAVATION: ____

EXCAVATION DETAILS: CENTERLINE GPS COORDINATES (BASED ON GIS):
NORTHING: ____ PLANNED EXCAVATION LENGTH (FT.): ____
EASTING: ____ ACTUAL EXCAVATION LENGTH (FT.): ____
CENTERLINE GPS COORDINATES (UNCORRECTED FIELD MEASUREMENT): GPS FILE NAME: ____
NORTHING: ____
EASTING: ____
CENTERLINE 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										
FEET	0	1	2	3	4	5	6	7	8	9	10

FORM H: DIRECT EXAMINATION DATA SHEET 2 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: ____________

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 MACROTECH TO LOCATE & IDENTIFY TYPE (SEE TABLE 5.7.3, ELEMENT 2.2)

2.3 GIRTH WELD COORDINATES:

NORTHING: ____________
EASTING: ____________
ELEVATION: ____________

WELD CLOCK POSITION: ____________

2.4 DAMAGE FOUND:
CORROSION DAMAGE ☐YES ☐NO MECHANICAL DAMAGE ☐YES ☐NO
OTHER DAMAGE: ____________

2.5 UT WALL THICKNESS EASUREMENTS: 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 MEASURMENT GRID FOR ADDITIONAL INFORMATION

Zero Reference Point: ____________
FLOW ⟶

*NOTE ANY CALCAREOUS DEPOSITS.

12 O'CLOCK										
9 O'CLOCK										
6 O'CLOCK										
3 O'CLOCK										
12 O'CLOCK										

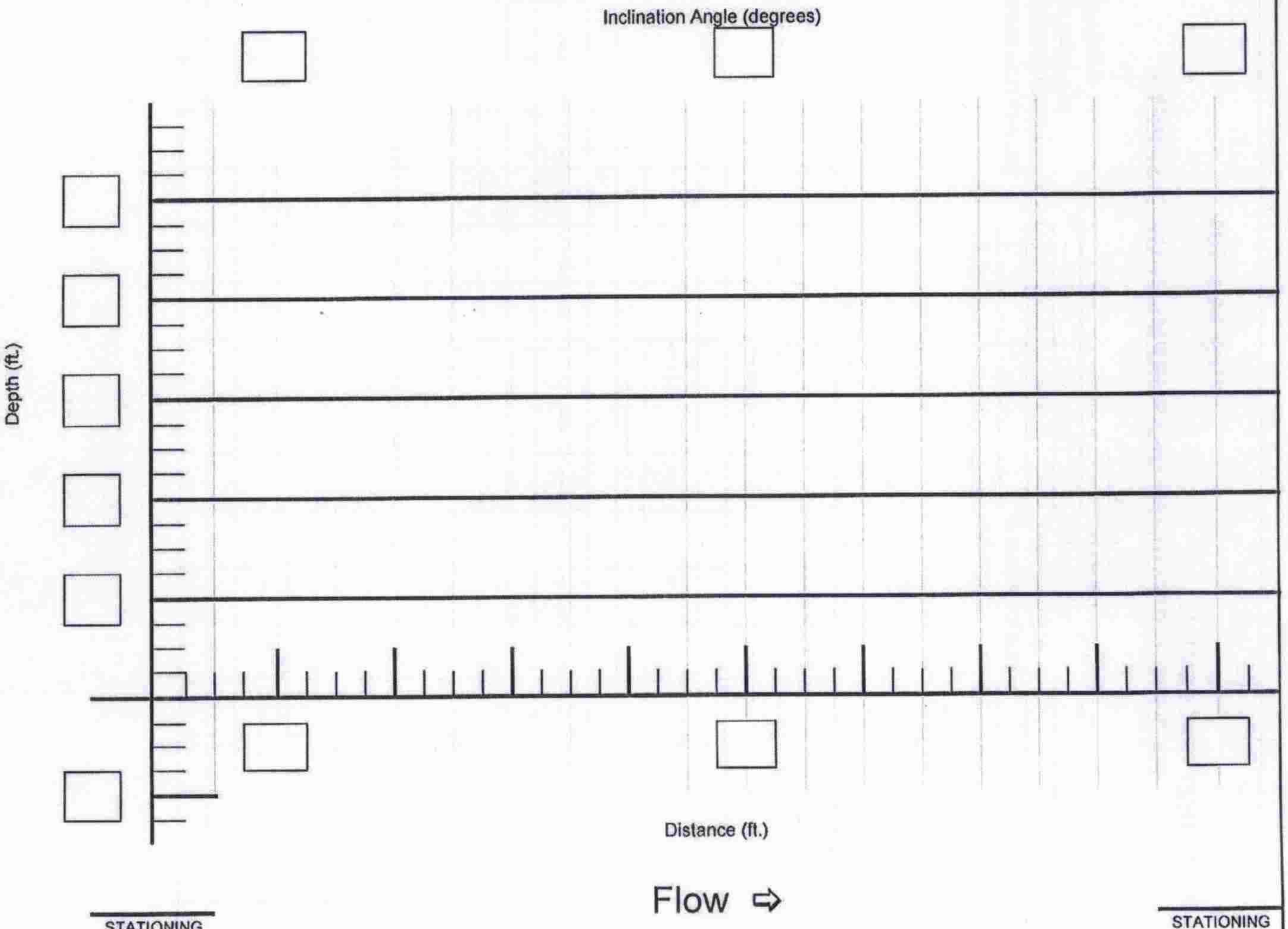
FEET 0 1 2 3 4 5 6 7 8 9 10

FORM H: DIRECT EXAMINATION DATA SHEET 3 OF 10

DA/ILI		DA		ILI	
ROUTE NUMBER:		N-SEGMENT:		ILI LOG DISTANCE:	
EXAMINATION DATE		IMA NUMBER:		RMP-11 REF. SECTION:	Table 5.6.2
MILE POINT:				REFERENCE GIRTH WELD:	
EXAMINATION PERFORMED BY:		REGION NUMBER:		DISTANCE FROM GIRTH WELD:	
PG&E PROJECT MANAGER:		SUBREGION # (ICDA)			
APPROVED BY:		STATIONING:			
ORDER NUMBER:					

Excavation Drawing:

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



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

Form H: DIRECT EXAMINATION DATA SHEET - PAGE 4 OF 10

EXTERNAL PIT DEPTH MEASUREMENT GRID SHEETS

DA/ILI

ROUTE NUMBER: ______
EXAMINATION DATE ______
MILE POINT: ______
EXCAVATION 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 (SPECIFIY GRID SIZE)   ANOMALY #: ______   GRID #: ______

Clock Position (Specify below)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
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

Proprietary Information

Form H: DIRECT EXAMINATION DATA SHEET - PAGE 5 OF 10

EXTERNAL PIT DEPTH MEASUREMENT GRID SHEETS

DA/ILI

ROUTE NUMBER: ____________________

EXAMINATION DATE: ____________________

MILE POINT: ____________________

EXCAVATION PERFORMED BY: ____________________

PG&E PROJECT MANAGER: ____________________

APPROVED BY: ____________________

ORDER NUMBER: ____________________

DA

N-SEGMENT: ____________________

IMA NUMBER: ____________________

REGION NUMBER: ____________________

SUBREGION # (ICDA): ____________________

STATIONING: ____________________

ANOMALY #: ____________________

ILI

ILI LOG DISTANCE: ____________________

RMP-11 REF. SECTION: Table 5.6.2

REFERENCE GIRTH WELD: ____________________

DISTANCE FROM GIRTH WELD: ____________________

GRID #: ____________________

GRID SIZE = ______ INCH x ______ INCH (SPECIFIY GRID SIZE)

Clock Position (Specify Below)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
A																								
B																								
C																								
D																								
E																								
F																								
G																								
H																								
I																								
J																								
K																								
L																								
M																								
N																								
O																								
P																								
Q																								
R																								
S																								
T																								
U																								
V																								
W																								
X																								

PIT DEPTH GRID 2 OF 2

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

INTERNAL CORROSION PIT DEPTH GRID

DA/ILI

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 = _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
Page 1 of 1

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

COATING DAMAGE

DA/ILI

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

DA

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

ILI

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

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

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

CORROSION LOG

DA/ILI

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.)

Form H: Direct Examination Data Sheet– Page 9 of 10

PHOTO LOG

DA/ILI

ROUTE NUMBER:

EXAMINATION DATE:

MILE POINT:

EXAMINATION PERFORMED BY:

PG&E PROJECT MANAGER:

APPROVED BY:

ORDER NUMBER:

DA

N-SEGMENT:

IMA NUMBER:

REGION NUMBER:

SUBREGION # (ICDA)

STATIONING:

ILI

ILI LOG DISTANCE:

RMP-11 REF. SECTION: Table 5.6.2

REFERENCE GIRTH WELD:

DISTANCE FROM GIRTH WELD:

PHOTO NO.	LOCATION	DESCRIPTION	COMMENTS

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

DA/ILI

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: ______

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 ______ 1200: ______
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 NEEDED, 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 4.2 NUMBER OF REPAIR MADE: ______
4.3 REPAIR TYPE: ☐METALLIC SLEEVE ☐NON METALLIC SLEEVE ☐REPLACE ☐CAN ☐FILLER METAL ☐OTHER
4.4 DAMAGE REPAIRED: ☐CORROSION ☐MECHANICAL ☐OTHER

MISC. COMMENTS/INFO: ______

Form H – Direct Examination Data Sheet (Casings Only) - Page 1 of 1

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: ______

1.0 BEFORE CASING REMOVAL (AS FOUND)

NOTE: ALL TESTING PERFORMED BELOW GRADE

1.1 C/S BEFORE CASING IS REMOVED (-MV): ______ 1.2 P/S BEFORE CASING IS REMOVED (-MV): ______

1.3 CASING TYPE ☐ PIPE ☐ NESTABLE ☐ CORRUGATED ☐ SPLIT PIPE ☐ COMBINATION (EXPLAIN): ______
☐ OTHER (LIST): ______

1.4 MEASURED CASING DIAMETER (IN): ______

1.5 WAS CASING DAMAGED? ☐ NO ☐ YES

IF YES EXPLAIN: ______

1.6 WAS CASING COATED? ☐ NO ☐ YES

IF YES, EXPLAIN COATING TYPE AND CONDITION: ______

______

1.7 CASING ☐ HIGH SIDE ☐ LOW SIDE

1.8 WAS THERE A VENT PIPE ATTACHED TO CASING? ☐ NO ☐ YES

1.8.1 VENT CLOCK POSITION: ☐ 12:00 ☐ 6:00 ☐ OTHER (EXPLAIN): ______

______

2.0 AFTER PORTION OF CASING REMOVED (AS LEFT)

NOTE: PHOTOS ARE REQUIRED FOR EACH PHYSICAL ITEM BELOW

2.1 HOW MUCH CASING WAS REMOVED?: ______

2.2 CASING VERIFICATION FLUSH: ☐ 2.2.1 METHOD USED: ______

2.3 VENT CLOCK POSITION: ☐ 12:00 ☐ 6:00 ☐ OTHER (EXPLAIN): ______

2.4 DIAMETER OF VENT: ______ 2.5 DIAMETER OF VENT OPENING IN CASING: ______

2.6 WAVE GUIDE INSTALLED: ☐ YES ☐ NO 2.7 SPACERS INSTALLED: ☐ YES ☐ NO

2.8 END SEALS INSTALLED: ☐ YES ☐ NO 2.8.1 TYPE OF END SEAL(S): ______

2.9 5 PSI seal Pressure Test: ☐ PASS 2.10 VENT AIR FLOW TEST (USING HIGH VOLUME COMPRESSOR): ☐ PASS

2.11 C/S AFTER CASING IS REMOVED (-MV): ______ 2.12 P/S AFTER CASING IS REMOVED (-MV): ______

2.13 TYPE B TEST STATION INSTALLED: ☐ YES

2.14 END OF CASING GPS COORDINATES: NORTHING: ______ EASTING: ______

DA Form I: ECDA Remaining Strength Evaluation and Root Cause Analysis (Page 1 of 3)

DATE OF EVALUATION:________________
INDICATION STATION ING________________
INITIAL PRIORITY:________________
N-SEGMENT # :________________
ROUTE #:________________

MP RANGE:________________
REGION NUMBER:________________
PM:________________
PE.:________________

PIPE DATA FROM FORM H

DIA.:________ WALL THICKNESS:________ MATERIAL:________ SMYS:________ MAOP:________ CLASS LOCATION:________

AREA OF CORROSION WITH LOWEST BURST PRESSURE

LENGTH________ WIDTH________ MAX PIT DEPTH = ________ RSTRENG BURST PRESSURE = ________

PREDICTED BURST PRESSURE DETERMINATION (*Pf*):

PF:________ SF_{CORR} (PF/MAOP):________ SF_{DR}: ☐ 1.39 ☐ 1.67 ☐ 2.00 ☐ 2.50 PIPE REPAIR REQUIRED: ☐ YES ☐ NO

Comments:

ANALYST:________________ DATE:________________ DATE OF NOTIFICATION:________________

PEOPLE NOTIFIED:________________
____
____
____

DA Form I (2 of 3): ECDA Root Cause Analysis Report

ROUTE NUMBER: ____________ IMA NUMBER: ____________
DATE OF EXCAVATION: ____________ REGION NUMBER ____________
MILE POINT: ____________ DATE REQUIRED: ____________
EXAMINATION PERFORMED BY: ____________
PROJECT MANAGER: ____________
APPROVED BY: ____________

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

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

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

Extent of Coating Degradation: ____________

Max. Depth of Corr.: ____________
Max Length of Corr.: ____________
Comments:

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

Comments:

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

IIT Results Before Excavation:

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

Other Information:

Review of Existing Damage Mitigation Measures:

4/5/2010

DA Form I (3 of 3): ECDA Root Cause Analysis Report

ROUTE NUMBER: ____________________
DATE OF EXCAVATION: ____________________
MILE POINT: ____________________
EXAMINATION PERFORMED BY: ____________________
PROJECT MANAGER: ____________________
APPROVED BY: ____________________

IMA NUMBER: ____________________
REGION NUMBER ____________________
DATE REQUIRED: ____________________

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:

IS ECDA WELL SUITED TO IDENTIFY DAMAGE FROM THE CAUSE DESCRIBED ABOVE? ☐ YES ☐ NO
DOES ROOT CAUSE REQUIRE REPRIORITIZATION OF INDICATIONS? ☐ YES ☐ NO
DOES ROOT CAUSE REQUIRE REPEAT INDIRECT INSPECTIONS? ☐ YES ☐ NO

ECDA PE or Designate: ____________________ Date: __________
Manager, Integrity Management: ____________________ Date: __________

DA Form J: Reprioritization

DATE OF EVALUATION: ____________________
N-SEG. ____________________
ROUTE #: ____________________

MP RANGE: ____________________
REGION NUMBER: ____________________
PROJECT ENGINEER: ____________________
PM: ____________________

Prioritization Evaluation

MP or MP Range of Indication	Dig Stationing	IIT Priority Form G	Region #	SF_{corr}	Class Location	SF_{DR}	Max Corrosion Depth	Actual Priority	Reprio. Yes/No	New Priority	Compliance Criteria Met	Comments

PE or Designate: ____________________ Date: ____________________

Reprioritized Indirect Inspection Indications From Above Analysis

MP or MP Range of Indication	Dig Stationing	Original Priority	New Priority	Range of Reprioritization	Affected Regions	Comments

PE or Designate: ____________________ Date: ____________________

Project Manager: ____________________ Date: ____________________

DA Form K: Remaining Life Determination

DATE OF EVALUATION: ______________________
INDICATION STATIONING: ______________________
REPRIORITIZED PRIORITY: ______________________

N-SEGMENT #: ______________________
ROUTE NUMBER: ______________________
MP RANGE: ______________________
PROJECT ENGINEER: ______________________

PIPE DATA:
DIA.:________ WALL THICKNESS:__________ MATERIAL:_________ SMYS:_________ MAOP:________ CLASS LOCATION:______

REMAINING LIFE CALCULATION:

MP Range & Stationing	Priority	Yield Pressure	Pf	SF_{DR}	MAOP	t	CR	RL	Reassess Interval

Comment:____

PE OR DESIGNATE:______________________ DATE: ______________________

PROJECT MANAGER:______________________ DATE:______________________

SUPERVISING ENGINEER OF TIMP:______________________ DATE______________________

MANAGER INTEGRITY MANAGEMENT:______________________ DATE______________________

$$RL = \frac{0.85}{YP}\left[Pf - MAOP\right]\frac{t}{CR}$$ where:

RL = Remaining Life (years)

YP = Yield Pressure (psi)

Pf = Burst Pressure by RSTRENG (psi)

SF_{DR} = Design Requirement Safety Factor (Table 5.5.1)

$MAOP$ = Maximum Allowable Operating Pressure (psi)

t = Thickness (in.)

CR = Corrosion Rate (mils/year)

DA Form L: ECDA Performance Report

DATE OF REPORT:__________ ECDA REGION:__________

N-SEG:__________ PROJECT ENG:__________

ROUTE NUMBER:__________ MP START:__________ MP FINISH:__________ PM:__________

	CIS	DCVG	PCM	Other
INDIRECT INSPECTION: Length (ft):	______	______	______	______

	Immediate	Scheduled	Monitored	NI
Number of indications: (Before Reprioritization)	______	______	______	______
Number of indications: (After Reprioritization)	______	______	______	______

	Immediate	Scheduled	Monitored	NI
DIRECT EXAMINATION: Number of Excavations:	______	______	______	______
Remaining Life:	______	______	______	______
Safety Factor Responses:	______			

Number of Reprioritizations: Higher Priority______ Lower Priority______ M to NI______

Number of Repairs: ______

Length and coordinates for pipe to be replaced: ____________________

POST ASSESSMENT:

Reinspection Interval: __________

Missed Deadlines: __________

Exceptions: __________

PE or Designate:____________________

Project Manager:____________________

DA Form M: Exception Report

DATE OF REPORT:__________________ ECDA REGION:__________________________

N-SEG:________________________ PROJECT ENG:__________________________

ROUTE NUMBER:__________ MP START:__________ MP FINISH:__________ PM:__________________________

Paragraph Number of Exception:__________

Requirements of paragraph (Your own words): ______________________________

Alternative Plan: ______________________________

Reason for Exception: ______________________________

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

COMMENTS: ______________________________

PE or Designate:____________________ **Date:**____________________

Project Manager:____________________ **Date:**____________________

Supervising Engineer of TIMP:____________________ **Date:**____________________

Manager, Integrity Management:____________________ **Date:**____________________

Proprietary Information

DA Form N: Dig Sheet

DATE: ____________________

STARTING MILE POINT: ____________________

ENDING MILE POINT: ____________________

N-SEGMENT NUMBER: ____________________

ROUTE NUMBER: ____________________

PM: ____________________

N-seg	Route	Mile Point		Sta For DE	Coordinates[1]		Priority	Governing Tool – Class[2]	Region[3]	Schedule Order	Cover Type	Depth to	Pipe	Pipe W.T.	D.E. Type[5]	CIS Potentials		PCM	Comments[6]	Status
		From	To		Northing	Easting						T.O.P[4] (in.)	Dia. (in.)			On (-mV)	Off (-mV)			

Notes:

[1] **Coordinates** = Coordinate system shall be UTM NAD83 Zone 10N (Meters).

[2] **Governing Tool Class** = Responses would be either , CIS,PCM or DCVG which ever is most severe.

[3] **Region 1** = Coatings (i.e. HAA, FBE, Powercrete, Tape, Xtru Coat, etc.); **Region 2** = Possibly hand applied coating locations with a high probability of installation flaws, including field applied Polyken Tape (TAPE) or Coal Tar Enamel, locations to be at angle points, valves, tees, and taps to District Reg Stations and large customer meter sets; **Region 4** = Water Crossings (To include 4A and 4B); **Region 5** = Bare pipe; Region; 6 = Spans; **Region 7** = Station piping

[4] **T.O.P.** = Top of Pipe

[5] **D.E. Type** :

- **Req** = Required Dig
- **Add 1st** = Additional dig for first time ECDA
- **O.I.N. > 20%** = Spec'd out only if Immediate indication (priorities) exist in the Nseg region
- **O.I.N.** = Only If Needed due to other considerations for the case of when there were no Immediates in that region – such as not finding the expected coating.
- **P.E.D.D** = Project Engineer's Discretionary Dig
- **Eff Req*** = Effectiveness dig required
- **Eff 1st *** = Effectiveness dig required for first time ECDA
- ***Effectiveness digs shall be dug last**

[6] **FL** = Foreign Line Crossing

Are the indirect inspection test data sets consistent with each other and do they align? Yes or No ________

After verifying indirect inspection results with pre-assessment results, is ECDA feasible? Yes or No ________

PE or Designate: ______________________________ **Date:** ______________

Project Manager: ______________________________ **Date:** ______________

Supervising Engineer of TIMP: ______________________________ **Date:** ______________

Manager, Integrity Management: ______________________________ **Date:** ______________

DA Form O: Indirect Inspection Field Meet

Division/ District:	
Supervisor:	
Notification Date:	
Meeting Date:	
Attendees:	

Review	Check if completed	Comments
Schedule		
ECDA Regions		
CP Equipment		
Inspection Tools		
Access to ECDA Regions		
Landowner Contact		
Safety Hazards		
Changes to Indirect Inspection Plan		

Notification Procedure: Contractor shall notify the PM or his designate when abnormal conditions or situations develop. These can be; extreme data, unusual landowner contact, pipeline safety concerns, inspection tool does not appear appropriate, personnel injury and changes in inspection dates and times.