PACIFIC GAS AND ELECTRIC COMPANY

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GAS TRANSMISSION & DISTRIBUTION ENGINEERING DEPT
CORROSION ENGINEERING SECTION

Procedure for Dry Gas Internal Corrosion Direct Assessment

Procedure No. RMP-10

Integrity Management Program

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1.0 PURPOSE

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

2.0 INTRODUCTION

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

2.1 Scope

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

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

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

2.2 DG-ICDA Steps

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

The four steps of the process are:

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

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

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

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

2.3 Roles and Responsibilities

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

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

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

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

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

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

2.4 Qualifications

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

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

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

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

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

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

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

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

2.5 Definitions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Natural Gas: Primarily methane as produced from natural sources.

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

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

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

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

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

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

Should: A recommendation that is desirable to follow.

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

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

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

3.0 PIPELINE SEGMENTS REQUIRING DG-ICDA

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

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

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

4.0 PRE-ASSESSMENT

4.1 Objectives

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

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

4.2 Data Collection

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

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

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

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

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

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

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

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

4.3 Pre-Assessment Review Meeting

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

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

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

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

4.3.3 **Recommended Attendees:**

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

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

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

4.4 Sufficient Data Analysis

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

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

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

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

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

4.5 Assessment of DG-ICDA Feasibility

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

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

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

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

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

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

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

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

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

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

4.6 Pre-Assessment Report

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

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

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

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

5.0 IDENTIFICATION OF ICDA REGIONS

5.1 Objectives

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

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

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

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

5.2 Flow Modeling Calculations

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

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

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

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

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

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

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

5.2.4.1 Convert the temperature into Rankine

$T(R) = T(^oF) + 459.67$

5.2.4.2 Calculate the gas density, ρ_G

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

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

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

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

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

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

5.2.4.5 Calculate the superficial gas velocity, V_g

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

5.2.4.6 Calculate the critical angle, θ

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

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

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

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

5.3 **Elevation Profile Calculations**

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

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

5.4 **Inclination Profile Calculations**

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

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

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

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

5.5 **ICDA Region Selection**

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

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

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

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

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

5.5.2.2 The "Considered" and "Not Required" elements listed under "Region Selection" in Form A: Data Collection Form, may be taken into account when establishing DG-ICDA regions.

5.5.3 A new DG-ICDA region shall consider each current inlet, any inlets that were current at the time of the previous DG-ICDA (but are no longer being used), and any historic inlets that have shown internal corrosion during past DG-ICDA assessments. Route changes should also be considered, as these may affect the locations of liquid holdup.

5.5.3.1 **1st Time Requirements:** The first time that DG-ICDA is performed on a given pipe segment testing for liquids other than water and items such as the potential for MIC shall be performed. To determine severity or corrosivity of these locations, the results shall be compared to the "Triggers For Internal Corrosion Corrective Work" given in Appendix F.

5.5.3.2 **Subsequent Investigations:** After the first assessment is performed, any internal corrosion occurring as a result of past liquid upsets will have already been identified.

- If no corrosion has been found, then future corrosion may only occur as a result of liquid upsets from current inlets.
- If corrosion is found, subsequent assessments to determine growth rate and/or active corrosion should be performed.

5.5.4 Any affects on flow and pressure attributed to compressor and valve locations may be considered, as they may cause significant changes in superficial gas velocity, affecting the critical inclination angles.

5.5.5 Pressure and temperature changes over the segment length may be considered, as these changes can induce water condensation or affect the critical inclination angle.

5.5.6 If there has been bi-directional flow through the pipeline, each direction shall be treated separately. Therefore, it may happen that the center area of a pipeline is considered unlikely to have internal corrosion while the two ends are areas of concern.

5.5.7 In relatively level pipelines, it is possible that a region may not have any inclination angles greater than or equal to the critical inclination angle. If it can be documented that the critical inclination angle for the lowest flow conditions ever experienced by the region in question is never reached, then the region may be considered free from an internal corrosion threat. Any electrolyte introduced to this region would be transported through the entire region to the next downstream region, and would not be held-up anywhere in the upstream region.

5.5.7.1 If a region has ever experienced no flow, or there is not sufficient documentation of flow rates to establish the lowest experienced flow rate, then the region may not be eliminated as an internal corrosion threat.

5.5.8 For each region, the ICDA-PE shall identify the first upstream inclination angle greater than or equal to the critical inclination angle determined by flow modeling results.

5.5.8.1 If all inclination angles are smaller than the critical inclination angle, the largest inclination angle in the region shall be chosen.

5.5.9 In some cases, drips or other facility components may serve as liquid accumulation points. They may be used as DG-ICDA examination points if it can be demonstrated that they meet the following requirements:

- They are located within close proximity upstream of the selected site.
- They have a design operation and maintenance that effectively traps liquids.
- They have a corrosion environment that either represents or is more severe than the pipeline.

5.5.10 The ICDA-PE shall compare the sites selected with any prior internal corrosion indications and data obtained from the field visit to make sure that they are consistent and that direct examinations of these sites are possible.

5.6 Region Selection Report

5.6.1 The start and end locations of all DG-ICDA regions shall be documented on Form C in Appendix C. Distinguishing characteristics for each region may also be documented using Form C. The ICDA-PM, the ,ICDA-PE, and the Manager of Integrity Management shall review and sign this report. Records shall demonstrate compliance with 49 CFR Part 192 and shall be retained for the useful life of the pipeline.

5.6.2 The ICDA-PE shall prepare a report for each region. It shall include, but is not limited to the following:

- Statement regarding the accuracy and precision of the inclination profiles
- The results of all flow modeling calculations including Form D: Flow Modeling
- Sites selected for direct examination

Form C and Form D together shall satisfy this requirement. The report shall be signed by theIDCA PE, the ICDA-PM, and the Manager of Integrity Management. A copy shall be retained in the project file.

6 Identification Of Locations For Excavation and Direct Examination

6.1 Objectives

The objectives of the *Direct Examination* step are to:

- Select sites for direct examination
- Examine electrolyte trapping features
- Excavate and inspect selected sites
- Assess the extent of corrosion
- Perform remaining strength evaluation

Each step for conducting direct examinations will be described in the following paragraphs.

During the *Direct Examination* step, defects other than internal corrosion (e.g., external corrosion, stress corrosion cracking, or mechanical damage) may be found. If defects from sources other than internal corrosion are identified, UO Standard S4134 "Selection of Steel Gas Pipeline Repair Methods" should be consulted to determine the appropriate action.

The Pipeline Engineer shall be consulted before any repairs are made.

6.2 Selection of DG-ICDA Excavation Sites

6.2.1 The ICDA-PE shall follow the process identified below to select the sites for direct examination in each DG-ICDA region. Any deviation from this process must be justified based on sound technical principles and be approved by the ICDA-PM, and the Manager of Integrity Management .

6.2.2 **Required by Code:** For every DG-ICDA region containing at least one HCA-covered-segment, a minimum of two excavations and direct examinations must take place within an HCA-covered-segment (per 192.927(c)(3)).

6.2.2.1 "One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the HCA-covered-segment nearest to the beginning of the ICDA Region." (per 192.927(c)(3)(i))

6.2.2.2 "The second location must be further downstream, within a covered segment, near the end of the ICDA Region." (per 192.927(c)(3)(ii)) The end of the ICDA region is the location where the ICDA model predicts electrolytes could accumulate based on the critical angle of inclination above which electrolyte film cannot be transported by the gas (per Protocol D.08(b)(iii)).

6.2.3 **Electrolyte Trapping Features:** If the trap geometry restricts evaporation, it is possible for corrosion to be more severe inside a downstream trap. Therefore, the pipeline operator should consider examing at least one feature where electrolyte can be trapped directly downstream of a pipe inclination angle greater than the critical inclination angle.

6.2.3.1 The electrolyte trapping feature may serve as a DG-ICDA examination location if it meets the requirements described in 5.5.10.

6.2.4 Additional examinations may be performed as deemed necessary by the ICDA-PE.

6.2.5 When the DG-ICDA process identifies internal corrosion based on inspection results, the ICDA-PE shall do one of the following:

- Perform additional direct examinations on potential liquid holdup locations identified for that region in the *Indirect Inspection* step
- Perform another type of integrity assessment on that region

6.2.6 The sites selected for direct examination shall be documented and kept within the project file. Form E: Site Selection for Direct Examination, in Appendix C, shall be used for this documentation. .

6.3 Pipe Excavation and Inspection

6.3.1 All pipe excavations shall be in accordance with PG&E Utility Operations Guideline G14413 "Procedure for Excavating Pipeline and Services".

6.3.2 Low points (e.g. sags) may be particularly vulnerable to internal corrosion because liquid accumulates at these locations during periods of stagnant flow. Therefore, for each DG-ICDA excavation site, examination should begin at the low point immediately upstream of the critical inclination angle and continue downstream until the critical inclination angle is reached. Sufficient pipe shall be examined to verify the presence or absence of internal corrosion.

6.3.2.1 Examination length may be shortened if there is a corrosion monitoring device installed as a result of a prior assessment within identified excavation length.

6.3.3 The location and size of the excavation site shall be identified and recorded on Form F: Direct Examination Data Sheet, in Appendix C. The center and ends of each excavation shall be located and recorded with a GPS instrument. The length of exposed pipe shall be physically measured and recorded on Form F. The GPS coordinates shall be stored in an electronic file and copied on the contractor's project CD.

6.3.4 The ICDA-PM may have the excavation expanded in length if it appears that the internal corrosion may extend beyond the boundaries of the excavation. The expansion shall be performed cautiously and documented on Form F: Direct Examination Data Sheet.

6.3.5 A pipe level (angle finder with magnetic base) or equivalent may be used to measure inclination angles. Inclination angles and the stationing at the low point shall be recorded on Form F. Detailed data on the pipe condition is also important to record.

6.3.6 The pipe shall be inspected by a person that is qualified by PG&E Operator Qualification Program to perform the task of "Corrosion Control 03-05". The individual shall complete Form F: Direct Examination Data Sheet. Any deviation from these procedures shall be identified and approved by the Manager of Integrity Management.

6.3.7 ILI , including tethered pig technology devices, may be used as a detailed direct examination tools. Guided wave ultrasonic inspections may also be used to augment the direct examination process. For both cases the bell hole for launching these devices shall be of sufficient length to allow direct physical examination of a sample of detected anomalies so that verification of tool accuracy can be established. Similarly, if hand held tools are used then detailed and accurate measurements of the wall thickness and axial length of any wall loss indications shall be performed.

6.3.7.1 Minimum wall thickness within corroded areas must be identified.

6.3.7.1.1 Ultrasonic thickness measurements, radiography, or another generally accepted technique may be used to make these measurements. Measurements must be performed by individuals qualified by training or experience.

6.3.8 The severity of all defects must be evaluated, and the pipe shall be repaired if necessary according to UO Standard S4134 "Selection of Steel Gas Pipeline Repair Methods". All remediation of HCA-covered-segments must be conducted in accordance with 49 CFR 192.933.

6.3.9 Indications suspected of having causes other than internal corrosion (i.e. dents) must be investigated using UO Standard S4134 "Selection of Steel Gas Pipeline Repair Methods Attachment 2-Calculation to Determine the Estimated Strain in a Dent".

6.3.10 Improvements for real-time monitoring and future site accessibility may be installed at the time that the excavation is taking place.

6.3.10.1 Once a pipeline is exposed, consider installing a corrosion monitoring device (i.e., corrosometer probe, corrosion coupon, ultrasonic sensor, electrical resistance matrix, etc.) that may allow the determination of inspection intervals and provide monitoring in the location most susceptible to internal corrosion.

6.3.11 **Documentation:** The location and size of the excavation site and the results of the *Direct Examination* shall be documented using Form F: Direct Examination Data Sheet.

6.4 Remaining Strength Evaluation and Notification of Immediate Response

6.4.1 The purpose of the remaining strength calculations is to determine the predicted burst pressure at corroded areas to assure that it meets the Area Class Location Design Requirements.

6.4.2 The predicted burst pressure may be calculated using the RSTRENG calculation methodology in all corroded areas with a wall loss greater than 20%. Other analytical techniques, such as linear elastic fracture mechanics, ASME B-31G, etc, may be used as deemed appropriate with approval by the Manager of Integrity Management, or designate.

6.4.3 An individual qualified to use RSTRENG shall perform any RSTRENG calculations. The qualification records shall be maintained in the Integrity Management Program file.

6.4.4 The safety factor for the evaluated area shall be determined by:

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

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

$MAOP$ = *Maximum allowable operating pressure*

Pf = *Predicted failure Pressure*

6.4.5 The safety factor shall be compared with the safety factor for the class location of the evaluated area. Table 3 in Appendix A provides the corresponding safety factor for each class location. If SF_{corr} is less than SF_{DR} specified for a given location, a repair will be required.

6.4.6 An immediate repair is necessary if any of the following conditions are met (according to 49 CFR 192.933 (d)):

- A remaining strength calculation shows an SF_{corr} 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.
- An indication or anomaly that in the judgment of the qualified person evaluating the assessment results requires immediate action.

If an immediate repair is necessary the pipeline pressure shall be reduced or the line temporarily shut down.

6.4.7 If a pressure reduction is necessary, the pressure shall be reduced using ASME/ANSI B31G or "RSTRENG" or the operating pressure shall be reduced to a level not exceeding 80% of the operating pressure at the time the condition was discovered (49 CFR 192.933 (a)).

6.4.8 The ICDA-PM shall work with the Pipeline Engineer to have the damage per UO4134 remediated in order to restore the pipe to the MOP with the appropriate safety factor specified in Table 3. Alternatively, the MOP may be reduced to establish the safety factor.

6.4.9 **Notification:** If any of the immediate repair conditions are met, the following people shall be contacted:

- ICDA-PM
- Responsible Pipeline Engineer
- Manager of Integrity Management
- Manager of Pipeline Engineering

The ICDA-PM or the Pipeline Engineer shall communicate and document all required pressure/operational changes to Gas System Operations (GSO) and the date that this determination is made shall be documented on Form G: Remaining Strength Evaluation, in Appendix C.

6.4.10 Where evidence of corrosion was found the ICDA-PE shall evaluate the potential for corrosion in all pipeline segments in the pipeline system with similar characteristics to the DG-ICDA region in which the corrosion was found. Both covered and non-covered segments shall be evaluated. Any corrosion discovered during these evaluations shall be remediated according to 49 CFR 192.933.

6.4.11 **Documentation:** The results of the remaining strength evaluation and the RSTRENG calculation shall be documented in Form G: Remaining Strength Evaluation, in Appendix D.

6.5 Root Cause Analysis

6.5.1 **Process:** The ICDA-PE shall perform a root cause analysis for each area of corrosion associated with a location where pipe was removed.

6.5.2 The root cause analysis should identify the corrosion mechanism by identifying the main drivers for corrosion in the area including liquid and gas chemistry, solids, and corrosive microbes and determine recommendations to mitigate the degradation.

6.5.3 **Documentation:** The root cause of internal corrosion performed shall be documented in the project file and summarized on Form H: Root Cause Analysis. A root cause analysis can cover multiple corrosion indications provided that they are similar in all characteristics listed in Section 6.5.2.

6.5.4 **DG-ICDA Evaluation:** If the root cause analysis identifies a degradation mechanism that the DG-ICDA process is not well suited to detect, the mechanism and its location shall be documented according to 6.5.3. A suitable assessment method shall then be used to evaluate those segments of pipe that are vulnerable to the identified mechanism.

6.5.5 Corrective actions taken to address the root cause during the *Direct Examination* step shall be documented on Form H.

6.6 Direct Examination Report

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

6.6.1 The ICDA-PE shall prepare a *Direct Examination* report for each DG-ICDA region and have it signed by the ICDA-PM. Form I: DG-ICDA Direct Examination Overview Report, in Appendix C, shall be used for this purpose.

6.6.2 The report should include but is not limited to the following:

- Characteristics and boundaries of DG-ICDA regions, if applicable.
- Inspection, excavation, and repair procedures.
- Data collected before and after the excavation:
  - Length and actual inclination of the exposed pipe at each location
  - Data used to identify other areas that may be susceptible to corrosion
  - Data used to estimate corrosion growth rates

  If corrosion was found:
  - Measured metal-loss corrosion geometries
  - Defect analysis, remaining strength, and root cause analysis results
  - Planned mitigation activities

7 Post Assessment

7.1 Objectives

The objectives of the *Post Assessment* step are to:

- Determine any necessary continual monitoring for internal corrosion
- Assess the overall effectiveness of the DG-ICDA process
- Determine the remaining life of the pipeline segment
- Determine the reassessment interval

The process for conducting the *Post Assessment* step of a DG-ICDA are outlined below. Each step will be described in the following paragraphs.

7.2 Continual Monitoring of Internal Corrosion

7.2.1 Continual monitoring of HCA-covered-segments where internal corrosion was found shall be performed in compliance with 49 CFR Part 192.927.

7.2.2 Continual monitoring techniques may include one or more of the following:

- Coupons
- UT Sensors
- Electronic/Corrosometer Probes

- Periodically drawing off liquids at low points and chemically analyzing them for the presence of corrosion products.

Each technique requires proper data interpretation. The frequency of monitoring shall be based on root cause analysis and severity of corrosion found.

7.2.3 If there is evidence of corrosion products, prompt action shall be performed. Action taken in an HCA-covered-segment in the ICDA region shall also comply with 49 CFR 192.933, and one of the two following required actions shall be conducted:

- Excavations of HCA-covered-segments at locations downstream from where electrolyte may have entered the pipe.
- Assessment of the HCA covered-segment using another integrity assessment method allowed by 49 CFR Part 192.

7.3 Assessment of DG-ICDA Effectiveness

7.3.1 Data from the three previous steps shall be analyzed to evaluate the effectiveness of DG-ICDA as an assessment method for addressing internal corrosion.

7.3.2 Effectiveness of the DG-ICDA process can be determined by the correlation between detected corrosion and the DG-ICDA predicted locations. Other methods may also be used.

7.3.2.1 If corrosion was found downstream of the first site selected based on the maximum critical inclination angle, the ICDA-PE shall re-evaluate the critical inclination angle.

7.3.2.2 DG-ICDA for gas pipelines is based on the premise of intermittent upsets. While most such pipelines should have little or no corrosion, the presence of extensive corrosion at many locations or the presence of corrosion on the top of the pipeline suggest that this premise may have been violated.

7.3.3 Per 49 CFR Part 192, evaluation of DG-ICDA effectiveness of HCA-covered-segments must be completed within one year of commencement of the DG-ICDA Direct Examinations (ref 192.927 (c)(4)(i)).

7.3.4 Per ASME B31.8S-2001, Section 9.4, the following performance measures should be tracked:

- Number of miles of pipeline inspected versus program requirements.
- Number of immediate repairs completed as a result of the integrity management program.
- Number of leaks, failures, and incidents (classified by cause).
- Number of repair actions taken due to direct assessment results.
- Number of internal corrosion leaks.

7.4 Determination of Remaining Life

7.4.1 The ICDA-PE shall select, technically justify, and validate the method(s) used for determining the corrosion rate. One or more of the following methods should be used:

7.4.1.1 Re-examine the site at a prescribed frequency to determine or assess the mean growth rate (i.e., monitor the site for corrosion growth on the actual pipe).

7.4.1.2 Install one or more corrosion monitoring devices at sites of predicted liquid accumulation based on flow modeling and/or other representative locations.

7.4.1.3 Apply a corrosion rate model based on operating conditions, gas quality, liquid composition, the presence or absence of IC, and other key factors.

7.4.1.4 For cases where no corrosion was found, skipping to direct use of ASME B31.8S Table 3 for determining the **reassessment interval** may be used.

7.4.2 The ICDA-PE shall calculate the remaining life of all excavation locations containing a corroded area with a wall loss greater than 20% by applying a corrosion rate to the corroded area that exhibits the lowest predicted burst pressure.

7.4.2.1 If the root cause analysis shows that the weakest corroded area is unique (and therefore not representative of the dominant degradation mechanism), then the next weakest corroded area may be used to determine the remaining life.

7.4.2.2 The equation below shall be used to calculate the remaining life:

$$RL = \frac{0.85}{YP}\left((Pf - MAOP)\frac{t}{CR}\right)$$

Where

RL = Remaining Life (years)

YP = Yield Pressure (psi)

Pf = Failure Pressure from RSTRENG (psi)

MAOP = Maximum Allowable Operating Pressure (psi)

t = Actual Uncorroded Wall Thickness (inches)

CR = Corrosion Rate (inch/year)

7.4.2.3 **Documentation:** The remaining life shall be documented on Form J: Remaining Life Determination, in Appendix D.

7.5 Reassessment Intervals

7.5.1 The reassessment interval for a DG-ICDA region shall not exceed one-half of the shortest remaining life calculated in section 7.4.2, as applicable. For additional requirements on maximum intervals see ASME B31.8S Table 3

7.5.2 According to 49 CFR Part 192.939, the maximum reassessment interval for HCA-covered-segments is seven years.

7.5.2.1 If a reassessment interval greater than seven years is established, a confirmatory direct assessment, in accordance with 193.931, shall be performed on the HCA-covered-segment within the seven-year period. A follow-up reassessment shall then be conducted at the interval established in section 7.5.1.

7.5.3 Data must also be evaluated to determine whether HCA-covered-segments should be reassessed at more frequent intervals than those stated in 49 CFR 192.939.

7.6 Post Assessment Report

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

7.6.3 The ICDA-PE shall prepare the *Post Assessment* repot. It shall contain, but is not limited to the following:

7.6.3.1 Remaining life calculation results

- Maximum remaining flaw size determinations
- Corrosion growth rate determinations
- Method of estimating remaining life

- Results of remaining strength calculations

7.6.3.2 Reassessment intervals and scheduled activities, if any

7.6.3.3 Correlation between corrosion found and sites predicted by DG-ICDA

7.6.3.4 Monitoring records

Forms G through K shall satisfy this requirement, but other documents may be used to augment the report.

7.6.4 **Communication of Recommended Mitigation Plan:** Communication of Recommended Mitigation Plan shall be made to communicate mitigation tasks that pertain to the line being assessed. The following responsible parties, as appropriate, should be included on this communication:

Responsible Pipeline Engineer, T&R Supervisor or District Superintendent, Responsible Senior Gas Distribution Engineer, ICDA-PE, ICDA-PM, etc.

7.6.5 The ICDA-PE shall complete Form K: DG-ICDA Performance and Effectiveness Report, in Appendix C, for each DG-ICDA project. The report shall be approved by the ICDA-PM and filed in the project file. The report shall include the following:

7.6.5.1 A summary of the Pre-Assessment Data Collection Form, including data from direct examinations and other data as appropriate.

7.6.5.2 A summary of the *Inspection* results, comparing the results from the calculated inclination angles with the actual values and the predicted corrosion sites with any corrosion observed during excavation.

7.6.5.3 A summary of the *Direct Examination* results, including the number of excavations performed, the remaining life of the pipe where internal anomalies were found, and the number of repairs or immediate actions.

7.6.5.4 A summary of the *Post Assessment* results, including the shortest calculated re-inspection interval for the DG-ICDA project, the results of the DG-ICDA effectiveness assessment, and feedback for future projects.

8.0 Exception Process

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

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 DG-ICDA 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.

8.2 Exception Requirements: The following process is required for taking an exception with this procedure. It shall be documented on Form L: Exception Report:

8.2.1 **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.

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

8.2.3 **Reason:** Provide the reason the exception is needed.

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

8.2.5 **Approval:** Obtain approval from the Manager of Integrity Management or designate prior to acting on the exception.

8.2.6 Documentation: Document the above items on Form L: Exception Report. Place all approved exception reports in the project file.

9 DG-ICDA PROJECT REPORTS

9.1 Project Report

The ICDA-PM shall prepare a report and submit it for approval to the Manager of System Integrity. The report should be filed in the DG-ICDA project file.

9.2 Contents

The report should contain the following information:

- Form A: Data Collection Form
- Form B: Feasibility Assessment Report
- Form C: DG-ICDA Region Report
- Form D: Flow Modeling
- Form E: Site Selection for Direct Examination
- Form F: Direct Examination Data Sheet
- Form G: Remaining Strength Evaluation
- Form H: Root Cause Analysis
- Form I: DG-ICDA Direct Examination Overview Report
- Form J: Remaining Life Determination
- Form K: DG-ICDA Performance and Effectiveness Report
- Form L: Exception Report

APPENDICES

Appendix A

PRE-ASSESSMENT DATA COLLECTION

Table 1: Data for Use of Dry Gas DG-ICDA Methodology

ID #	Data Element	REQUIRED/ Desired	Feasibility Assessment	Identification of DG-ICDA Regions	Use & Interpretation of Results
1.	**PIPE RELATED**				
1.1	Diameter	REQUIRED	Internal diameter must be within flow model range.	Consider, but is accounted for in the flow modeling.	Used in flow calculations to determine the critical inclination angle past which liquid carry-over is not expected. New critical inclination angles should be calculated for any length with a significant change.
1.2	Wall thickness	REQUIRED		Not Required	Required to calculate the internal diameter (see 1.1). Also, impacts critical defect size and remaining life prediction of results.
1.3	Internal Coatings	REQUIRED	ICDA not appropriate for locations with internal corrosion protective coatings. The presence of flow coatings should also be considered.	Not Required	Approved alternative internal corrosion integrity assessment method should be considered for lengths containing internal coatings.
1.4	Seam type	REQUIRED	If pre-1970 low-frequency electric resistance welded (ERW) or flash welded pipe located along the bottom half of the pipeline, DG-ICDA may not be appropriate.	Not Required	Location with pre-1970 low-frequency electric resistance welded (ERW) or flash welded pipe with increase selective seam corrosion susceptibility may require separate consideration.
1.5	Material and grade	Desired	ICDA may not be appropriate for nonferrous materials.	Consider	Special consideration should be given to locations where dissimilar metals are joined. Can create local corrosion cells when exposed to the environment.
1.6	Year manufactured	Desired		Not Required	Older pipe materials typically have lower toughness levels, which reduces critical defect size and remaining life predictions.
2.	**CONSTRUCTION RELATED**				
2.1	Year installed	REQUIRED	ICDA will not find corrosion from previous service (e.g., reclaimed pipe).		Impacts corrosion rate estimates.
2.2	Type and locations of current and historic (removed) inlets and outlets, tie-ins, taps, insulating joints, drains, drips, cast iron components. Locations, data on any route changes/ modifications.	REQUIRED	1) Consider economic implications of applying DG-ICDA to pipeline with numerous inlets. 2) Locations of drips, drains or other features where liquid hold-up may occur must be identified. 3) Special consideration should be given to locations at which dissimilar metals are connected.	Not Required. May define new regions at each current or historic inlet. Outlets (current and historic) should also be considered in region definition if it is possible there has been liquid input at these locations.	May impact interpretation of results; dissimilar metals may create local corrosion cells at points of contact. Information on orientation of features may assist in identification of those necessary to examine for internal corrosion.
2.3	Locations of compressors, and valves	REQUIRED		Not Required. Should be considered during region definition; significant differences in superficial gas velocity may trigger new region definitions or may be considered in region analysis. Anywhere where electrolyte could condense should also be considered.	Use in flow calculations to determine the critical angle past which liquid carry-over is not expected. Because critical inclination angle is sensitive to differences in pressure, new critical inclination angles are calculated for lengths with significant changes in flow velocity.

ID #	Data Element	REQUIRED/ Desired	Feasibility Assessment	Identification of DG-ICDA Regions	Use & Interpretation of Results
2.4	Locations of road and electrolyte crossings (including roads no longer in service) and any associated casings/ river weights and anchors	REQUIRED	Consider economic and environmental implications of applying DG-ICDA to lengths of pipe containing multiple sites at difficult to access locations. May significantly restrict the *Direct Examination Step*. Additional tools and other assessment activities may be required.	Not Required, but may provide useful information on low spots where liquids could collect.	Special attention should be given to elevation changes at these locations; pipe depth measurements may be necessary to avoid extrapolating nearby results to inaccessible regions, which could introduce unacceptable error for DG-ICDA.
2.5	Route maps/aerial photos	REQUIRED	Assists in pipeline locating; precise location data required.	Consider. May provide information about route that would be useful to region definition. As-built information can be gathered for determining depth of cover and elevation.	Typically contain pipeline data that facilitate DG-ICDA. Essential to obtain coordinates of precise route location for purposes of elevation profiling with GIS/ USGS.
2.6	Construction practices	Desired	ICDA not desired for pipeline known or suspected to have experienced internal corrosion prior to or during installation. Mechanical damage may preclude use of DG-ICDA.	Not Required	
2.7	Proximity to other pipelines, structures, high voltage electric transmission lines, and rail crossings	Desired		Not Required	Affects site selection. Could make direct examinations difficult. May be associated with pipe depth changes. Provides critical information for use during direct examinations.
3.	**TOPOGRAPHICAL DATA**				
3.1	USGS maps or GIS surveys	REQUIRED	An accurate elevation profile (sub-meter) is essential to DG-ICDA. Tool used must be able to discern all important inclination angles. 1) If GIS is used, static or other high accuracy and precision method is required and sufficient data must be collected. Consider economic implications. 2) USGS data must have sufficient resolution. If USGS data is used, it may be necessary to supplement with quality GIS measurements in important locations (i.e., beginning of line to first site).	Consider	Locations of all low points should be identified. When collecting GIS (Geographic Information System) or USGS (U.S. Geological Survey) data, include marker locations (i.e., road and river crossings) in the comment section of the inclination spreadsheet, for future later reference during direct examinations.
3.2	Locations of exposed pipe, drips and crossovers	REQUIRED		Not Required. Consider including drips as their own region. Drips that are historically dry need not be considered.	Locations of all exposed pipe, drips and crossovers shoiuld be identified.
3.3	Elevation changes at roads, rivers, drains, valves, drips	REQUIRED	An accurate and precise inclination profile is required. If the tool used for data collection does not have sufficient discernment of these features it must be supplemented by pipe depth measurements, static GIS, and/ or another tool which can discern pipeline elevation.	Not Required, but is captured by flow modeling.	Special attention must be paid to these changes, which are not adequately captured in many topographical surveys. At these locations, pipe depth measurements may be necessary, as the elevation of the pipeline is likely to vary from the surface elevation.
3.4	HCA #s	REQUIRED		Not Required	The location of HCAs is necessary to determine what special requirements must be taken for a HCA-covered-segment (ie shorter re-assessment interval, continual monitoring, etc)
3.5	Depth of cover	Desired	Depth of cover measurements are recommended. These must be coordinated precisely with GIS or other data.	Not Required	May impact success of DG-ICDA. If significant inclinations are not captured, site selections are not expected to be accurate. It is recommended to collect pipe depth measurements simultaneous with GIS to avoid alignment issues.
4.	**OPERATIONAL DATA**				

ID #	Data Element	REQUIRED/ Desired	Feasibility Assessment	Identification of DG-ICDA Regions	Use & Interpretation of Results
4.1	Pipeline operating temperature	REQUIRED	Must be within flow model range.	Not Required, but is accounted for in flow modeling. Any significant changes (i.e., frozen ground) require consideration as these could affect liquid hold-up location.	Use in flow calculations to determine the largest critical inclination angle past which liquid carry-over is not expected. New critical inclination angles should be calculated for any length with a significant change.
4.2	Pipeline operating pressures	REQUIRED	Must be within flow model range.	Consider. Is accounted for in flow modeling, Significant changes in pressure (i.e., due to compressor) may trigger new DG-ICDA regions.	Collect minimum and maximum operating pressures. Use in flow calculations to determine the largest critical inclination angle past which liquid carry-over is not expected. New critical inclination angles should be calculated for any length with a significant change.
4.3	Pipeline operating flow rates	REQUIRED	Must be within flow model range.	Consider. New regions may be defined at current and historic inlets as these locations offer renewed liquid input potential. In case of bi-directional flow, regions may be defined for each gas flow direction.	Collect minimum and maximum flow rates at minimum and maximum operating pressures for all inlets and outlets. 1) Use in flow calculations to determine the largest critical inclination angle past which liquid carry-over is not expected. New critical inclination angles should be calculated for any length with a significant change. 2) Range of all gas velocities must be known. 3) Periods of low/no flow must be considered.
4.4	Corrosion inhibitor solubility (electrolyte/ oil), carrier (glycol/ aromatic), point of injection, dose rate, years of treatment, monitoring/ detection of inhibitor in any downstream liquids.	REQUIRED	Pipeline should not have a history of internal corrosion inhibitor use. If there is any history, technical justification should be provided.	Consider. Use of inhibitors can complicate determining the locations of any corrosion.	May impact DG-ICDA in unknown ways. If inhibitor provides partial but incomplete pipeline protection, DG-ICDA may not identify the most corroded locations. In these cases an alternative technique should be considered.
4.5	Type of dehydration	REQUIRED	Type of dehydration should be considered.	Not Required	Some dehydrating agents may encourage formation of sludge and solids or leave other residues. These may increase or decrease corrosion in locations at which they collect.
4.6	Service history	REQUIRED	If pipeline has been converted from a service for which DG-ICDA is not applicable (e.g., crude oil, products) DG-ICDA is not suitable.	Not required.	
4.7	Operating stress levels and fluctuations (% SMYS)	REQUIRED		Not required.	Impacts critical flaw size and remaining life predictions.
4.8	Data on liquid upsets	Desired	1) Dry gas DG-ICDA is intended for nominally dry gas pipelines. 2) Information on upsets may help anticipate extent of internal corrosion and possibility for any non-stratified flow conditions.	Consider. If liquid is known or suspected to have entered the line from outlets, these should be included in region definition.	Collect data on liquid upsets, including frequency (intermittent/ chronic), nature of liquid, volume (if known), location, and potential damage resulting from these upset conditions. History of liquids in the line is useful in assessing likelihood and possible severity of internal corrosion in the pipeline. The dry gas DG-ICDA method is based on assumption of stratified flow.
4.9	Electrolyte Vapor	REQUIRED	Dry gas DG-ICDA is intended for normally dry gas pipelines, which implies normal operation at temperatures well above electrolyte dew point.	Not Required. Locations of vapor may be included in establishing regions.	Operation of the pipe at temperature close to the electrolyte dew point may cause top of the line corrosion in locations not identified by DG-ICDA.

ID #	Data Element	REQUIRED/ Desired	Feasibility Assessment	Identification of DG-ICDA Regions	Use & Interpretation of Results
5.	**MONITORING DATA**				
5.1	Corrosion Monitoring	REQUIRED	1) Provides important supplementary information for DG-ICDA. 2) May provide information on presence and rate of internal corrosion. 3) Useful in defining reassessment intervals/ future monitoring.	Not required, but may be included in region definition.	Collect locations and information from monitoring programs (coupons, electric resistance (ER)/linear polarization resistance (LPR) probes, leak surveys, etc.)
5.2	Gas analyses	REQUIRED	Gas composition factors that may result in accelerated corrosion rate should be evaluated.	Not required, but may be included in region definition.	Presence of CO_2, H_2S, or O_2 may accelerate internal corrosion. Their effects must be considered.
6.	**INSPECTION AND REPAIR DATA**				
6.1	Pipeline inspection reports – excavation	REQUIRED	Dry gas DG-ICDA may not be applicable for pipelines with history of internal corrosion on the top of the pipeline.	Not required.	May impact repair; remediation, replacement schedules.
6.2	Repair history/ records.	REQUIRED		Not required.	Collect repair history and records – such as steel/ composite repair sleeves, repair locations, etc. Repaired pipeline may mask an internal corrosion problem. For locations which are to be detail examined it is essential to know when excavated pipe has been repaired in the past and its condition previous to repair. Use this information in combination with current direct examinations in making further dig site selections.
6.3	Leak/rupture history (internal corrosion)	REQUIRED		Consider. IC leak locations may be included in region analysis.	Collect location and nature of leaks and failures. This is essential for DG-ICDA dig site selection. Prior internal (or suspected internal) corrosion leaks must be considered concurrent with direct examinations in making further site selections.
6.4	Hydrostatic test	REQUIRED		Not Required	Collect hydrostatic data (dates, pressures, electrolyte quality). Provides information on past presence of electrolyte.
6.5	Presence of solids, liquids	REQUIRED	Pipelines that contain accumulations of solids, sludge, or scale can effect the locations of corrosion and the effectiveness of Dry Gas DG-ICDA. The influence of those materials should be evaluated.	**REQUIRED**	Document presence of solids and liquids in the pipe. If available, include analytical data of all removed sludge, liquids when cleaning pigs were employed or from liquid separators, hydrators, etc. and the analysis performed to determine the chemical properties and corrosivity, including the presence of bacteria, of the removed products. The presence of solids, sludge, and scale may affect the ability to predict where internal corrosion will occur.
6.6	Prior integrity-related activities – maintenance and ILI pigging, etc.	REQUIRED	ICDA is not intended for pipelines that have been or are currently being pigged. The effect of pigging should be evaluated for its possible effect on the accuracy of DG-ICDA.	Not Required	Collect locations, frequency, and dates of other prior integrity-related activities, such as maintenance and ILI pigging (including ILI from mainlines attached to legs on which DG-ICDA is being performed). Maintenance pigging affects where liquids collect, which directly affects the distribution of internal corrosion in a way not predicted by DG-ICDA. The operator must provide technical justification when DG-ICDA is applied to a pipeline that has any history of routine maintenance pigging.

Table 2: Possible Effects of Solids and Sludges on Pipeline Internal Corrosion

	Action	Effect
1	Retain electrolyte inside a porous matrix or under a solid layer	Increases corrosion
2	Attract electrolyte through hygroscopic properties and/ or deliquescence	Increases corrosion
3	Formation of a concentration cell (i.e., under deposit corrosion)	Increases corrosion
4	Formation of a protective layer	Decreases corrosion

Table 3: Design Requirements by Area Classification

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

Appendix B

Examples of pipeline inclinations and critical angles calculations (NACE Appendix A)

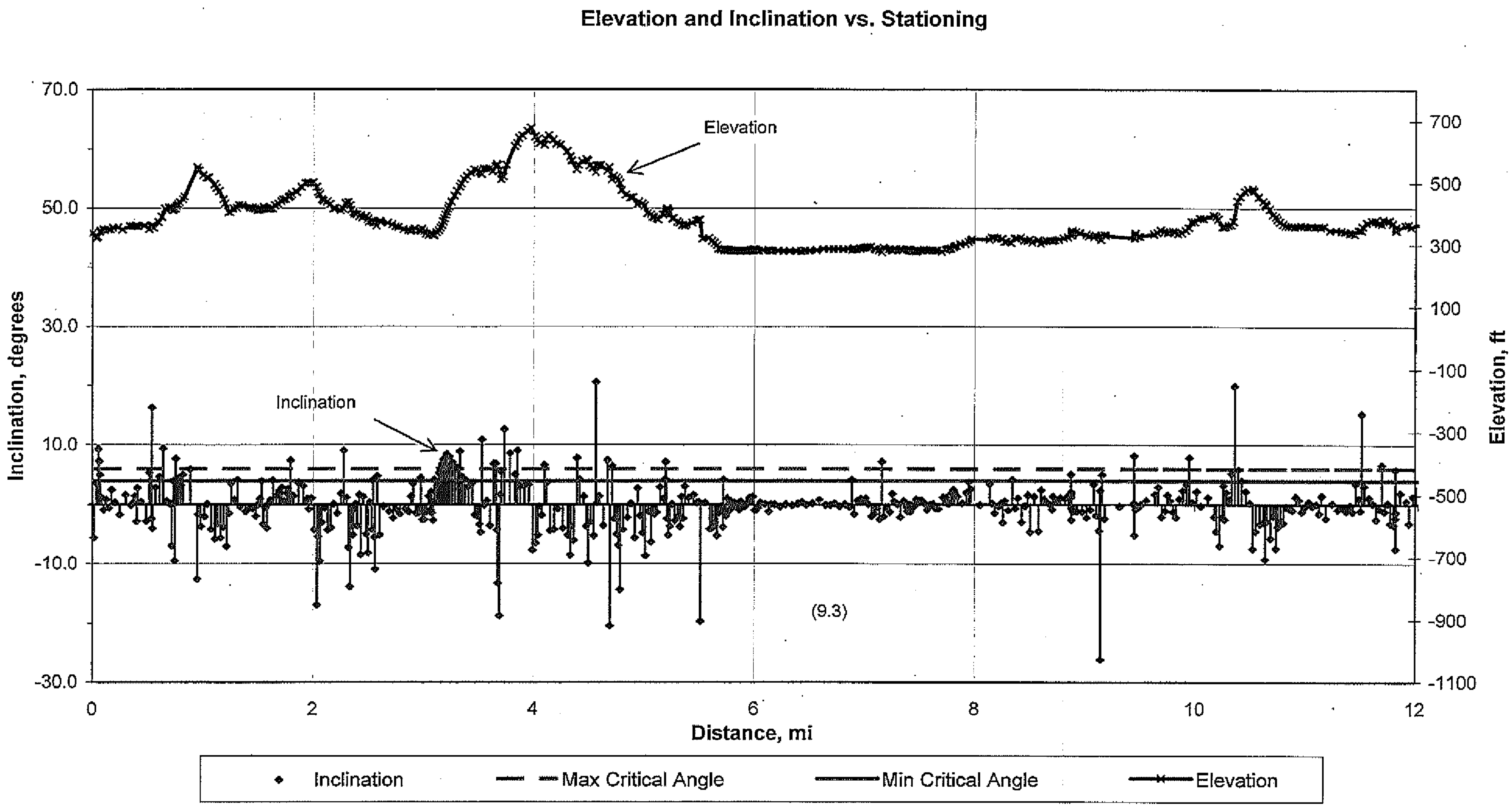


Figure 1: Sample plot of inclination, elevation, and critical angle for a segment of pipe.

APPENDIX C

DG-ICDA REPORT FORMS

FORM A: Data Collection Form

DG-ICDA Project Name:__________
Starting Mile Point:__________
Ending Mile Point:__________
Station Discharge:__________

Date:__________
Line Number:__________
ICDA-PM:__________

Instructions: This form shall be completed in accordance with Paragraph 4.2.6 of the procedure. The ICDA-PM or designate shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the Data Obtained field. Information in the Comments filed should include, as a minimum the reason required data is not available.

ID #	Data Element	Requirements				Data Sources[3]	Collection Complete (initial)	Data Obtained	Comments
		Need[1]	Feasibility Assessment[2]	Region Selection[2]	Interpretation Analysis[2]				
1.0	**PIPE RELATED**								
1.1	Diameter	R	R	C	R				
1.2	Wall thickness	R	R	N/R	R				
1.3	Internal Coatings	R	R	N/R	R				
1.4	Seam Type	R	C	N/R	C				
1.5	Material and grade	D	C	C	C				
1.6	Year manufactured	D	N/R	N/R	R				
2.0	**CONSTRUCTION RELATED**								
2.1	Year installed	R	R	N/R	R				
2.2	Type and locations of current and historic inlets and oultlets, tie-ins, taps, insulating joints, drains, drips, cast iron components. Locations, data on any route changes/ modifications.	R	R	N/R	R				
2.3	Location compressors and valves	R	N/R	N/R	C				
2.4	Locations of road and electrolyte crossings and any associated casings/ river weights and anchors	R	C	N/R	R				

[1] R = Required, D = Desired, N/R = Not Required
[2] R = Required, C = Considered, N/R = Not Required
[3] Data Sources: Division/Archive Files, GIS, Field, Pipeline Databases, Maps, Other

FORM A: Data Collection Form

DG-ICDA Project Name:______________________
Starting Mile Point:______________________
Ending Mile Point:______________________
Station Discharge:______________________

Date:______________________
Line Number:______________________
ICDA-PM:______________________

Instructions: This form shall be completed in accordance with Paragraph 4.2.6 of the procedure. The ICDA-PM or designate shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the Data Obtained field. Information in the Comments filed should include, as a minimum the reason required data is not available.

ID #	Data Element	Requirements				Data Sources[3]	Collection Complete (initial)	Data Obtained	Comments
		Need[1]	Feasibility Assessment[2]	Region Selection[2]	Interpretation Analysis[2]				
2.5	Route maps/ aerial photos	R	R	C	R				
2.6	Construction practices	D	C	N/R	C				
2.7	Proximity to other pipelines structures, HV electric transmission lines and rail crossing	D	N/R	N/R	C				
2.8	Internal Coating	R	R	D	R				
3.0	TOPOGRAPHICAL DATA								
3.1	USGS maps or GIS surveys	R	R	C	R				
3.2	Locations of exposed pipe, drips, and crossovers	R	R	N/R	C				
3.3	Elevation changes at roads, rivers, drains, valves, drips	R	R	N/R	C				
3.4	HCA #s	R	C	N/R	R				
3.5	Depth of cover	D	C	N/R	C				

[1] R = Required, D = Desired, N/R = Not Required
[2] R = Required, C = Considered, N/R = Not Required
[3] Data Sources: Division/Archive Files, GIS, Field, Pipeline Databases, Maps, Other

FORM A: Data Collection Form

DG-ICDA Project Name:____________________
Starting Mile Point:____________________
Ending Mile Point:____________________
Station Discharge:____________________

Date:____________________
Line Number:____________________
ICDA-PM:____________________

Instructions: This form shall be completed in accordance with Paragraph 4.2.6 of the procedure. The ICDA-PM or designate shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the Data Obtained field. Information in the Comments filed should include, as a minimum the reason required data is not available.

ID #	Data Element	Requirements				Data Sources[3]	Collection Complete (initial)	Data Obtained	Comments
		Need[1]	Feasibility Assessment[2]	Region Selection[2]	Interpretation Analysis[2]				
4.0	**OPERATIONAL DATA**								
41	Pipeline operating temperature	R	R	N/R	R				
4.2	Pipeline operating pressures	R	R	C	R				
4.3	Pipeline operating flow rates	R	R	C	C				
4.4	Corrosion inhibitor solubility, carrier, dose rate, years of treatment, monitoring, detection of inhibitor in downstream liquids.	R	R	C	C				
4.5	Type of dehydration	R	R	N/R	C				
4.6	Service history	R	R	N/R	C				
4.7	Operating stress levels and fluctuations (% SMYS)	R	N/R	N/R	R				
4.8	Data on liquid upsets	D	C	C	C				
4.9	Electrolyte Vapor	R	R	N/R	C				
4.10	History of IC leaks	R	C	D	C				
4.11	Received Gas from Gathering or Storage Lines	R	C	D	D				

[1] R = Required, D = Desired, N/R = Not Required
[2] R = Required, C = Considered, N/R = Not Required
[3] Data Sources: Division/Archive Files, GIS, Field, Pipeline Databases, Maps, Other

FORM A: Data Collection Form

DG-ICDA Project Name:____________________
Starting Mile Point:____________________
Ending Mile Point:____________________
Station Discharge:____________________

Date:____________________
Line Number:____________________
ICDA-PM:____________________

Instructions: This form shall be completed in accordance with Paragraph 4.2.6 of the procedure. The ICDA-PM or designate shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the Data Obtained field. Information in the Comments filed should include, as a minimum the reason required data is not available.

ID #	Data Element	Requirements				Data Sources[3]	Collection Complete (initial)	Data Obtained	Comments
		Need[1]	Feasibility Assessment[2]	Region Selection[2]	Interpretation Analysis[2]				
5.0	**MONITORING DATA**								
5.1	Corrosometer Probe Reads	R	R	N/R	C				
5.2	Gas analyses	R	C	N/R	R				
5.3	Bacteria Culture Test Records	R	C	N/R	R				
5.4	Drip Locations	R	C	N/R	R				
5.5	History of Liquids	R	C	N/R	R				
5.6	Chemical Analyses Of Liquids	R	C	N/R	R				
5.7	Acid Gas Partial Pressures	R	C	N/R	D				
5.8	Dew Point Records	D	C	D	D				
5.9	Previous Foam Pigging Activities	R	R	D	D				
5.10	Other Corrosion Monitoring – LPR Probes, Weight Loss Coupons, etc.	R	D	N/R	R				
6.0	**INSPECTION AND REPAIR DATA**								
6.1	Pipeline inspection reports-excavation	R	R	N/R	C				
6.2	Repair history/records	R	C	N/R	R				

[1] R = Required, D = Desired, N/R = Not Required
[2] R = Required, C = Considered, N/R = Not Required
[3] Data Sources: Division/Archive Files, GIS, Field, Pipeline Databases, Maps, Other

FORM A: Data Collection Form

DG-ICDA Project Name:______________________ _
Starting Mile Point:______________________
Ending Mile Point:______________________
Station Discharge:______________________

Date:______________________
Line Number:______________________
ICDA-PM:______________________

Instructions: This form shall be completed in accordance with Paragraph 4.2.6 of the procedure. The ICDA-PM or designate shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the Data Obtained field. Information in the Comments filed should include, as a minimum the reason required data is not available.

ID #	Data Element	Requirements				Data Sources[3]	Collection Complete (initial)	Data Obtained	Comments
		Need[1]	Feasibility Assessment[2]	Region Selection[2]	Interpretation Analysis[2]				
6.3	Leak/rupture history (internal corrosion)	R	C	C	R				
6.4	Hydrostatic test	R	C	N/R	R				
6.5	Presence of solids, liquids	R	R	**R**	C				
6.6	Prior integrity- related activities – maintenance and ILI pigging, etc.	R	R	N/R	R				
6.7	Previous ICDA Assessments	R	N/R	N/R	R				
6.8	Type/frequency- third party damage	D	C	N/R	C				

Sufficient Data: Yes____ No____

ICDA-Project Engineer:______________________ **Date:**____________

ICDA-Project Manager:______________________ **Date:**____________

Manager of Integrity Management:______________________ **Date:**____________

[1] R = Required, D = Desired, N/R = Not Required
[2] R = Required, C = Considered, N/R = Not Required
[3] Data Sources: Division/Archive Files,. GIS, Field, Pipeline Databases, Maps, Other

FORM B: Feasibility Assessment Report

DG-ICDA Project Name:__________________________

Starting Mile Point:__________________________

Ending Mile Point:__________________________

Station Discharge:__________________________

Date:__________________________

Route Number:__________________________

ICDA-PM:__________________________

Instructions: This form shall be completed in accordance with Section 4.5.3 of the procedure. Place a check mark next to all conditions that apply to the given pipeline segment.

Conditions that may make DG-ICDA unfeasible

_____ The pipe normally contains liquids.
_____ A corrosion inhibitor has been used.
_____ The pipe has an internal coating that provides corrosion protection.
_____ The pipe has a history of pig cleaning.
_____ The pipe contains an accumulation of solids.
_____ There is pre-1970 low-frequency ERW or flash welded pipe located along the bottom half of the pipe.
_____ There are missing "required" data elements.
_____ Other:

Technical justification for proceeding with DG-ICDA process:__________________________

Extra actions that must be taken as a result of unfeasible conditions:__________________________

Is DG-ICDA feasible? ______ **Yes** ______ **No**

ICDA-Project Engineer:__________________________ **Date:**________________

ICDA-Project Manager:__________________________ **Date:**________________

Manager of Integrity Management:__________________________ **Date:**________________

FORM C: DG-ICDA Region Report

DG-ICDA Project Name:________________________ **Date:**________________________
Starting Mile Point:________________________ **Route Number:**________________
Ending Mile Point:________________________ **ICDA-PM:**____________________
Station Discharge:________________________

Instructions: This form shall be completed in accordance with Section 5.6.1. Refer to Table 1, Appendix A for more detailed information regarding Region Distinguishing Characteristics. If the distinguishing characteristic is not contained in the list below, list the characteristic under other, and provide a technical justification for it being used as a region distinguishing characteristic.

Region 1 – Consists of all piping where liquids could hold-up.

Possible Distinguishing Characteristics: Current or historic inlets, crossovers, drips, exposed pipe, bi-directional flow, significant change in temperature or pressure, liquids known or suspected to be present, significant difference in superficial gas velocity, other.

Region #	Region Start (geographical reference)	Region End (geographical reference)	Possible Distinguishing Characteristic, if applicable	Temperature, °F (min/max)	Pressure, atm (min/max)	Flow Rate, mmscf/d (min/max)	ID, in

*Justification for being considered a region distinguishing characteristic (if #10-Other):________________

ICDA-Project Engineer:________________________ **Date:**________________

ICDA-Project Manager:________________________ **Date:**________________

Manager of Integrity Management:____________________ **Date:**________________

FORM D: Flow Modeling

DG-ICDA Project Name: ____________________ **Date:** ____________________
Starting Mile Point: ____________________ **Route Number:** ____________________
Ending Mile Point: ____________________ **ICDA-PM:** ____________________
Station Discharge: ____________________

Instructions: This form shall be completed in accordance with Sections 5.2.6 of the procedure.

Flow Model Used: ____

Justification for using flow model if other than the model given in the procedure: ____________________

Comments: ____

Flow Modeling Results

Region #	ρ_g	OP Flow Rate	V_g	θ (critical inclination angle)	max θ, min θ, or other (specify)

ICDA-Project Engineer: ____________________ **Date:** ____________

ICDA-Project Manager: ____________________ **Date:** ____________

Manager of Integrity Management: ____________________ **Date:** ____________

FORM E: Site Selection for Direct Examination

ICDA Project Name:____________________
DG-ICDA Region #:____________________
Starting Mile Point:____________________
Ending Mile Point:____________________

Date:____________________
Line Number:____________________
ICDA-PM:____________________
Station Discharge:____________________

Instructions: This form shall be completed in accordance with Section 6.2.6 of the procedure. These sections provide instructions on determining site selections within each DG-ICDA region. It shall be noted in the Comments field if a site has been selected as a validation inspection.

Site #	Region #	Critical Inclination Angle	Site Calculated Inclination Angle	Site Start (geographical reference)	Site End (geographical reference)	Date Scheduled for Direct Examination	Comments

ICDA-Project Engineer:____________________ **Date:**____________

ICDA-Project Manager:____________________ **Date:**____________

Manager of Integrity Management:____________________ **Date:**____________

FORM F: DIRECT EXAMINATION DATA SHEET 1 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:		ICDA DESCRIPTOR:			
APPROVED BY:		STATIONING:			
ORDER NUMBER:					

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 F: DIRECT EXAMINATION DATA SHEET 2 OF 10

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

1.10 PHOTOS TAKEN?* ☐ YES ☐ NO
*SEE PHOTO LOG FOR ADDITIONAL INFORMATION.

1.11 COATING SAMPLE TAKEN? ☐ YES ☐ NO LOCATION OF SAMPLE: ____

1.12 LIQUID UNDERNEATH COATING? ☐ YES ☐ NO IF YES, PH OF LIQUID: ____

1.13 CORROSION PRODUCT PRESENT? ☐ YES ☐ NO IF YES, WAS SAMPLE TAKEN? ☐ YES ☐ NO
COMMENTS: ____

1.14 SOIL PH (SB ELECTRODE): UPSTREAM: ____ DOWNSTREAM: ____

2.0 DATA AFTER COATING REMOVAL

2.1 PIPE TEMPERATURE (°F): ____ MEASURED PIPE DIAMETER (IN.): ____

2.2 WELD SEAM TYPE: ☐ DSAW ☐ SSAW ☐ ERW ☐ SMLS ☐ SPIRAL ☐ LAP ☐ FLASH ☐ AO SMITH ☐ IF CAN'T DETERMINE, VISUALLY PERFORM MACROTECH TO LOCATE ELEMENT 2.2)

2.3 GIRTH WELD COORDINATES:
& IDENTIFY TYPE (SEE TABLE 5.7.3,

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 FORM–F 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 FORM-F. 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.

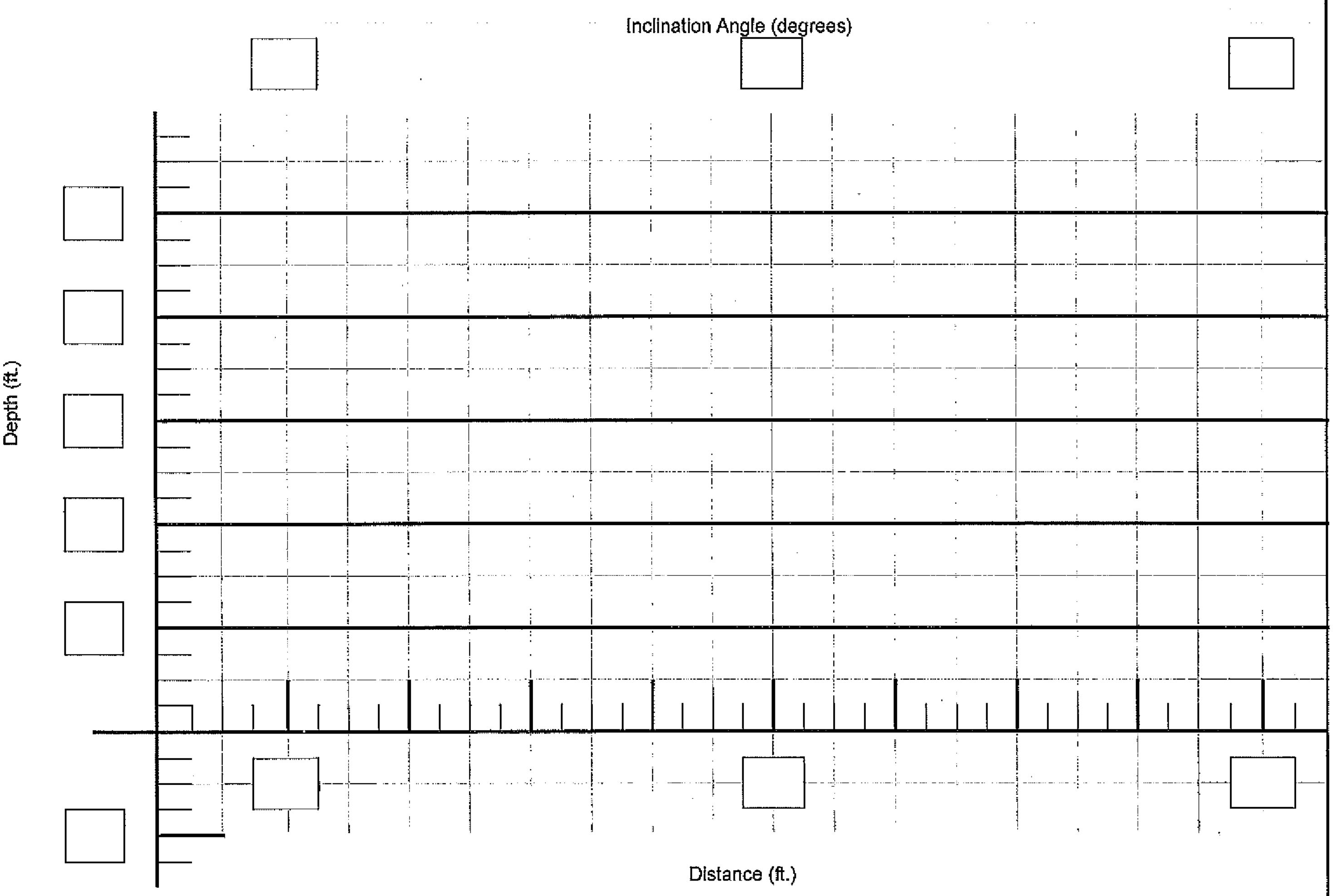
12 O'CLOCK										
9 O'CLOCK										
6 O'CLOCK										
3 O'CLOCK										
12 O'CLOCK										
FEET	0	1	2	3	4	5	6	7	8	9 10

FORM F: 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:		ICDA DESCRIPTOR:			
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").



Flow ⇨

STATIONING

STATIONING

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

material redacted

GTR0006988

FormF: DIRECT EXAMINATION DATA SHEET - PAGE 4 OF 10

EXTERNAL PIT DEPTH MEASUREMENT GRID SHEETS

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

GRID SIZE = ______ INCH x ______ INCH (SPECIFTY 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

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

EXTERNAL PIT DEPTH MEASUREMENT GRID SHEETS

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

ICDA DESCRIPTOR: ____

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

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: ____
ICDA DESCRIPTOR: ____
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 F: 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: ____________________

ICDA DESCRIPTOR: ____________________

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 F: 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: __________

ICDA Descriptor: __________

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 F: – Direct Examination Data Sheet - Page 10 of 10

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

3.0 Recoat Data

3.1 Sandblast Media: ____________ Anchor Profile Measurement: ____________

3.2 Pipe Recoated With:

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

3.3 For Epoxy Coating Systems, Record Environmental Condition:

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

3.4 Repair Coating Hardness (If ARC Coating): ____________

3.5 Measured Coating Thickness: 3:00 ______ 6:00 ______ 9:00 ______ 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: ____________

3.8 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 G: Remaining Strength Evaluation

ICDA Project Name:____________________
Evaluation Mile Point:____________________
Line Number:____________________
DG-ICDA Region Number(s): ____________
DG-ICDA Site Number:____________________

Date of Evaluation:____________________
Corrosion Technician:____________________
ICDA-PM:____________________
Station Discharge:____________________
Other Descriptor:____________________

Instructions: This form shall be completed in accordance with Section 6.4.9 of this procedure.

Pipe Information

Diameter:________ 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

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

Pipe Repair Required: ☐ Yes ☐ No

People Notified: ____________________
____
____
____

Date of Notification: ______________

Comments:____
____
____

ICDA-Project Engineer:____________________________ Date:____________

ICDA-Project Manager:____________________________ Date:____________

Manager of Integrity Management:____________________ Date:____________

FORM H: Root Cause Analysis

ICDA Project Name:______________
Starting Mile Point:______________
Ending Mile Point:______________
Station Discharge:______________

Date:______________________
Line Number:________________
ICDA-PM:__________________

Instructions: This form shall be completed in according with Section 6.5.3 of this procedure.

Liquid and Gas Chemistry:____

____

____

____

Solids Found? ______ **Yes** ______ **No**

If yes, Solid Composition:____

____

____

____

Corrosive Microbes Present? ______ **Yes** ______ **No**

Cause of Corrosion:____

____

____

____

Remedial Actions:____

____

____

____

Is ICDA well suited to identify damage from the cause described above? ______**Yes** ______ **No**

Comments:____

____

____

____

ICDA-Project Engineer:________________________ **Date:**__________________

ICDA-Project Manager:________________________ **Date:**__________________

Manager of Integrity Management:____________________ **Date:**__________________

FORM I: DG-ICDA Direct Examination Overview Report

ICDA Project Name:__________________ **Date of Evaluation:**__________________
Starting Mile Point:__________________ **Line Number:**__________________
Ending Mile Point:__________________ **ICDA-PGM:**__________________
Station Discharge:__________________

Instructions: This form shall be completed in accordance with Section 6.6.1 of the procedure.

Selected Site		ICDA Region #	ICDA	Design Wall Thick-ness (in.)	Rationale for Excavation (IC = Internal corrosion)				Results of Excavation						Date of Direct Examination and/ or General Comments	Mitigation and/or Scheduled Defect Re-assessment Date (from Post-assessment Calculation
										Internal Indication						
#	GIS Coordinates or Station # (indicate which)		Other Info		IC Found at Previous Site OR First Site Examined in Region	No IC Found at Previous Site ‡	No IC Found at Previous Two Sites ‡‡	HCA Location (Min. of 2 required per DG-ICDA Region)	Internal corrosion identified ? (yes/no)	Minimum Wall Thick-ness (in.)	Orientation (o-clock)	Inclination Angle at Indication (degrees)	Length (in)	Width (in)		

‡‡ Region Validation Site

ICDA-Project Engineer:____________________ **Date:**____________

ICDA-Project Manager:____________________ **Date:**____________

Manager of Integrity Management:____________________ **Date:**____________

FORM J: Remaining Life Determination

ICDA Project Name:________________
Starting Mile Point:________________
Ending Mile Point:________________
Station Discharge:________________

Date of Evaluation:________________
Line Number:________________
ICDA-PM:________________

Instructions: This form shall be filled out in accordance with Section 7.4.2.3 of the procedure.

Pipe Data
Diameter: __________ **Wall Thickness:**______ **Material:**________
SMYS:__________ **MAOP:**__________ **Class Location:**______

Region	Indication Location	Yield Pressure	Pf	MAOP	t	CR	RL	Reassess Interval*

Method used for Determining Corrosion Rate:____________________

Justification:____________________

Comments:____________________

$$RL = \frac{0.85}{YP}\left(\left(Pf - MAOP\right)\frac{t}{CR}\right)$$

where:
RL = Remaining Life (years)
YP = Yield Pressure (psi)
Pf = Predicted Failure Pressure (psi)
MAOP= Maximum Allowable Operating Pressure (psi)
t = Thickness (inch)
CR = Corrosion Rate (inch/years)

* Reassessment Interval ≤ RL/2 and ≤ 7 years if HCA covered segment (see Section 6.4)

ICDA-Project Engineer:________________ **Date:** __________

ICDA-Project Manager:________________ **Date:**__________

Manager of System Integrity:____________________ **Date:**______________

FORM K: DG-ICDA Performance and Effectiveness Report

ICDA Project Name:____________________ **Date of Report:**____________________
Starting Mile Point:____________________ **Line Number:**____________________
Ending Mile Point:____________________ **ICDA-PM:**____________________
Station Discharge:____________________

Instructions: This form shall be completed in accordance with Section 7.6.3 of this procedure.

Pre-assessment **Summary** (*Direct Examination* data can also be used to supplement the requested information below)

1.0 Pipe Related		**2.0 Construction Related**		**3.0 Topographical Data**	
Material and Grade		Year Installed		USGS maps/ GIS surveys	
Diameter		Inlets and Outlets		Elevation Changes	
Wall Thickness		Compressors and valves		Depth of Cover	
Seam Type		Road and Electrolyte Crossings		Exposed Pipe	
Internal Coating				HCA #s	
				Crossovers and Drips	
4.0 Operational Data		**5.0 Monitoring Data**		**6.0 Inspection and Repair Data**	
Temperature		Corrosion Monitoring		Inspection Records	
Pressure		Gas Analyses		Repair History	
Flow Rates		Bacteria Culture Tests		Leak/Rupture History	
%SMYS				Hydrostatic Test	
Electrolyte Vapor				Solids or Liquids (yes/no)	
Corrosion Inhibitor (yes/no)				Prior ILI or Pigging	
Dehydration (type)					
Service History					

FORM K: DG-ICDA Performance and Effectiveness Report

ICDA Project Name:______________________ **Date of Report:**____________________________
Starting Mile Point:______________________ **Line Number:**____________________________
Ending Mile Point:______________________ **ICDA-PM:**____________________________
Station Discharge:______________________

Instructions: This form shall be completed in accordance with Section 7.6.3 of this procedure.

Indirect Inspection **Summary**

DG-ICDA Region #	Critical Inclination Angle	Site #	Site Inclination Angle		Site Corrosion		Comments
			Calculated	Observed	Predicted	Observed	

Direct Examination **Summary**

	Corroded Area <10% Nominal Wall Thick.	Corroded Area 10-20% Nominal Wall Thick.	Corroded Area 20-50% Nominal Wall Thick.	Corroded Area > 50 % Nominal Wall Thick.
Number of Excavations				
Remaining Life (range of years)				
Immediate Responses				
Number of Repairs or Remediation Actions				

Post Assessment **Summary**
Re-inspection Interval:________

Exceptions: ________Yes ________No

Description: ____
____
____

Feedback:____
____
____

ICDA-Project Engineer:____________________________ **Date:**______________

ICDA-Project Manager:____________________________ **Date:**______________

Manger of Integrity Management:________________________ **Date:**______________

Form L: Exception Report

ICDA Project Name:________________________
Starting Mile Point:________________________
Ending Mile Point:________________________
Station Discharge:________________________

Date of Report:________________________
Line Number:________________________
ICDA-PM:________________________

Instructions: This form shall be completed in accordance with Section 8.0 of the procedure.

Paragraph Number of Exception:________________________

Requirements of paragraph (Your own words): ________________________

Alternative Plan: ________________________

Reason for Exception: ________________________

Recommendation: **Should the procedure be changed?** ______ **Yes** ______ **No**

Comments: ________________________

ICDA-Project Engineer:________________________ **Date:**____________

ICDA-Project Manager:________________________ **Date:**____________

Manager of Integrity Management:____________________ **Date:**____________

Appendix D

OPS Gas Integrity Management Protocols

OPS GAS INTEGRITY MANAGEMENT PROTOCOL REFERENCES

PROTOCOLS	RMP-12 SECTION NUMBER
D.06	
a.	Whole document
b.	3.5.2, 3.6, 4.5, 6.4
c.	3.6.4.1, 4.2.2, 4.5.4.2, 5.2.3.3
d.	2.1
e.	N/A
D.07	
a.	3.3.2
i.	Table 1 (1.1, 1.2, 2.1, 4.1, 4.2, 4.3, 4.7, 5.1, 5.2, 6.1, 6.3, 6.5)
ii.	Table 1 (2.2, 2.3, 3.1, 3.3, 4.2, 4.3)
iii.	Table 1 (4.8)
iv.	Table 1 (6.6)
b.	
i.	3.5
ii.	3.6
iii.	4.2
iv.	4.5
c.	4.2
D.08	
a.	5.2
b.	
i.	5.2.2
ii.	5.2.2.1
iii.	5.2.2.2
c.	
i.	5.3.8
ii.	5.5.3
iii.	5.5.4
D.09	
a.	
i.	5.2, 6.2.2.1
ii.	6.3, 6.4.1
iii.	6.4.1
b.	
i.	N/A
ii.	5.5.3, 5.5.4

APPENDIX E

TRIGGERS FOR INTERNAL CORROSION CORRECTIVE WORK

Triggers For Internal Corrosion Corrective Work

The following attributes for establishing internal corrosion control are hereby proposed as a basis for when additional action should be taken. An out of specification reading would be the basis upon which actions are required. Once these limits or triggers are programmed into PLM an automatic work request will be generated to respond to the out of tolerance attribute. The possible actions taken are those listed below, and are listed in decreasing order of preference. A single action or multiple actions can be taken.

Normal sampling frequency for Gas Gathering pipelines are provided in the table below. Normal sampling frequency foi Local Transmission and Backbone Transmission are more relaxed and are also provided in the table. Similarly, revised sampling frequencies based on documented evidence of no water being present for at least 3 consecutive times are provided in Footnote 1.

Table for All CGT Pipelines

Entry #	Species	Limit or Trigger	Gas Gathering PPL Normal Test Frequency (1)	Local Trans PPL - Normal Test Frequency (1)	Backbone PPL -Normal Test Frequency (1)
1	Corrosometer Probes	>2.0 mpy	Bimonthly	Semi-annually	Annually
----------	**Water Sampling (2)**	---------------	------------		
2	Fe	>30 ppm in water sample	Quarterly	Semi-annually	Annually
3	Mn	>2.0 ppm in water sample	Quarterly	Semi-annually	Annually
4	pH	< 6.0 as measured in water sample	Quarterly	Semi-annually	Annually
5	Conductivity	>20,000 micro-siemans/cm	Quarterly	Semi-annually	Annually
6	Cl	>30,000 ppm	Quarterly	Semi-annually	Annually
7	Inhibitor (2)	Present at <100 ppm	Quarterly	Semi-annually	Annually
8	Microbes – (via serial dilution)	> 1000 counts/ml	Semi annually (every 6-months)	Semi-annually	Annually
----------	**Gas Sampling**	---------------	------------		
9	CO_2	Partial pressure > 7 psi, with water present. Or >1.0 % concentration by volume.	As Needed –testing based on other test results also.	As Needed – testing based on other test results also.	As Needed – testing based on other test results also.
10	H_2S	Partial pressure > 0.03 psi with water present	As Needed – testing based on other test results also.	As Needed – testing based on other test results also.	As Needed – testing based on other test results also.

(1) When water testing at the normal frequency shows that there is no water present for 3 consecutive sample periods then the water sampling frequency can be decreased. For gas gathering the water sampling frequency can be decreased to 1 time per year, for Local Transmission to 1 time per year, and for Backbone Transmission to 1 time every 3 years. These revised frequencies should not exceed these limits in order to help maintain pipeline safety, and to mee the intent of the new Pipeline Safety Act. Note that for Line 300 South, the sampling frequency is 1 time per month. This is for environmental and personnel safety reasons (PCB's) and **not** because of internal corrosion concerns.

(2) All water samples should also be tested for the presence of inhibitor, to insure the substance is reaching the points of interest, and to verify the "reachout" or dispersal range of the chemical. Active ingredient in Baker Petrolite CGO 50 inhibitor is "thioamide." A test for this thioamide substance is currently being developed and evaluated for practicality.

File Name "Triggers For Internal Corrosion Corrective Work Reformatted For ICDA Procedure.rtf"

[redacted]
CGT Corrosion Engineer
[redacted]
1/3/2005