



Annual Corrosion Control Surveys

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference:	Procedure No.: HLD.20	
49 CFR: 195.573	<i>Effective Date:</i> 04/01/18	Page 1 of 6

1.0 Purpose This Standard Operating Procedure (SOP) describes how to conduct the Annual Corrosion Control Survey of company facilities.

2.0 Scope The Annual Corrosion Control Survey determines the adequacy of cathodic protection on company facilities, including buried metallic structures at pipelines, pump stations, measuring stations, pipeline terminals, towers, and tanks.

Annual Corrosion Control Surveys:

- Determine adequacy of cathodic protection.
 - Locate any potential corrosion areas.
 - Determine casing insulation status.
 - Locate interference problems.
 - Check the operation of cathodic protection facilities and bonds.
 - Determine any other corrosion related conditions requiring remedial measures.
 - Determine the adequacy of cathodic protection on buried, metallic structures at pipelines, pump stations, measuring stations, and pipeline terminals.
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3.0 Applicability Individual surveys apply to specific types of facilities and comprise the Annual Corrosion Control Survey. These individual surveys, listed below, ensure adequate level of cathodic protection for facilities as follows:

- Annual Pipeline Survey – all pipelines
 - Annual Station Survey – pump stations, measuring stations, breakout tanks, and pipeline terminals
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4.0 Frequency Once each calendar year at intervals not to exceed 15 months: Conduct the corrosion control survey of buried, submerged metallic assets to include tank bottoms in contact with soil.

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5.0 Governance The following table describes the responsibility, accountability, and authority of the operations described in this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	Definitions
Breakout Tanks	A tank used to (a) relieve surges in a hazardous liquid pipeline system or (b) receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline.
Buried tanks	Tanks buried in the ground, used to store gasoline, diesel, and other liquids at maintenance facilities and station yards. Buried tanks are usually protected from corrosion by galvanic anodes or by existing impressed current cathodic protection facilities.
Test point	Monitoring locations located at intervals along the pipeline to demonstrate the adequacy of cathodic protection. Test points must have test leads attached to the pipeline in accordance with SOP HLD.25 Cathodic Protection System Design (Appendices B and C).

7.0 Annual Corrosion Control Surveys This SOP contains the following sections:

- Annual Survey
- Annual Survey: Station
- Annual Survey: Breakout Tanks

7.1 Annual Survey Operations Personnel use the following procedure to prepare for and conduct all annual surveys.

Step	Activity
1	VERIFY that records or maps showing the location of each test point are available.

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NOTE: In order to have comparable data, tests should be made at the same points.

Step	Activity
2	USE electronic data collection equipment to take test measurements. Conventional test equipment should be used as a last resort to replace broken or out of service electronic equipment or for special testing procedures where an electronic data collector is not practical.



NOTE: Conventional testing requires writing information on report forms; electronic testing allows direct input to a field data terminal.

Step	Activity
3	GATHER previous survey data for reference during the survey. GRAPH historic rectifier output and structure-to-electrolyte potential trends. VERIFY that all CP current sources, to include bonds, electrical isolation devices, and grounding systems are functional and operating at / near historic output levels.
4	CHECK all necessary test equipment to ensure it is in good operating condition.
5	VERIFY that all CP current sources and bonds are operating properly. ADJUST tap settings, as required, during the CP current source / bond inspection if CP current source output depletion was noted during the records review.
6	REPAIR any non-operating CP current sources, bonds, electrical isolation devices, and grounding systems before the survey, where practical.
7	TAKE the structure-to-electrolytes measurements at test points in accordance with <i>SOP HLD.03 Structure-to-Electrolyte Potential Measurement</i> .
8	RECORD the following measurements in the Corrosion database: <ul style="list-style-type: none"> • Structure-to-electrolyte • Casing-to-electrolyte • Foreign line-to-electrolyte • Electrical isolation between company and foreign facility • CP current sources • Bonds
9	VERIFY the following information is recorded for each test point: <ul style="list-style-type: none"> • Date of tests • Test site number or other identification • Mile post/GPS reading/survey stations/location descriptor or station grid • Appropriate location remarks, such as foreign pipeline name or highway identification, should be updated annually

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NOTE: On pipelines affected by dynamic stray currents, use electronic or strip chart recorders.

Step	Activity
10	If data is collected electronically, TRANSMIT the data collected at the end of each workday (or at the earliest convenient time) to the computer.
11	VERIFY that the data was received by the computer prior to erasing the data.
12	COMPLETE and UPDATE Corrosion database within 30 days of completion of survey.
13	Upon completion of the survey, IDENTIFY any structure/casing-to-electrolyte potentials not meeting criteria in accordance with SOP HLD.22 Application of Cathodic Protection Criteria, DOCUMENT in form D.15.A Cathodic P/S Survey Analysis. Enter low potential areas in the LPA editor that do not meet the criteria and INITIATE necessary remedial work to include maintenance and repair of test points in accordance with <i>SOP HLD.40 Corrosion Control Remedial Action</i> .

7.2 Annual Survey: Station When conducting the annual station survey, Operations Personnel uses the following additional procedure.

Step	Activity
1	CONDUCT a station survey to determine the adequacy of cathodic protection on buried, metallic structures at pump stations, measuring stations, and pipeline terminals.
2	COLLECT pipe-to-soil potential data at a sufficient number of locations throughout the facility to define the protective status and VERIFY that adequate cathodic protection is being provided.
3	If locations indicate a possibility of inadequate protection, MEASURE additional potentials in the immediate area of the structure to determine the extent of possible inadequate protection.
4	COMPLETE the applicable form(s) and UPDATE Corrosion database within 30 days of completion of survey.
5	Upon completion of the survey, IDENTIFY any structure/casing-to-electrolyte potentials not meeting criteria in accordance with <i>SOP HLD.22 Application of Cathodic Protection Criteria</i> , DOCUMENT in form D.15.A Cathodic P/S Survey Analysis, and INITIATE necessary remedial work to include maintenance and repair of test points in accordance with <i>SOP HLD.40 Corrosion Control Remedial Action</i> .

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7.3 Operations Personnel conducts inspection of cathodic protection on buried steel storage tanks in contact with soil using the following additional procedure.
Annual Survey:
Buried Tanks

Step	Activity
1	CONDUCT an adequate number of structure-to-electrolyte measurements to DETERMINE the level of protection of the area around and over each tank. REFER to <i>SOP HLD.03 Structure-to-Electrolyte Potential Measurement</i> .
2	When installing tanks, CONSIDER providing permanent electrodes at appropriate locations. Permanent electrodes permit additional measurement of structure-to-soil potentials and improve the overall assessment of the cathodic protection levels at buried tanks.
3	COMPLETE and UPDATE Corrosion database within 30 days of completion of survey.
4	Upon completion of the survey, IDENTIFY any structure/tank-to-electrolyte potentials not meeting criteria in accordance with <i>SOP HLD.22 Application of Cathodic Protection Criteria</i> , DOCUMENT in form D.15.A Cathodic P/S Survey Analysis, and INITIATE necessary remedial work as described in <i>SOP HLD.40 Corrosion Control Remedial Action</i> .



NOTE: Verify continuity between tank and riser.

7.4 Operations Personnel conducts inspection of cathodic protection on At-Grade storage tanks in contact with soil using the following additional procedure.
Annual Survey:
AT-Grade Storage Tanks

Step	Activity
1	CONDUCT an adequate number of structure-to-electrolyte measurements to DETERMINE the level of protection of the area around and under each tank. REFER to <i>SOP HLD.03 Structure-to-Electrolyte Potential Measurement</i> .
2	UTILIZE permanent under tank reference electrodes and soil reference tubes when available for additional structure-to-electrolyte measurements. Permanent electrodes and soil reference tube structure-to-electrolyte measurements permit improved overall assessment of the cathodic protection levels on At-Grade Storage tanks.
3	UTILIZE CP coupons-to-reference electrode measurements if CP coupons are available
4	UTILIZE ER probes if available to evaluate CP effectiveness based on the ER probe corrosion rate
5	COMPLETE and UPDATE Corrosion database within 30 days of completion of survey.

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Step	Activity
6	Upon completion of the survey, IDENTIFY any structure/tank-to-electrolyte potentials not meeting criteria in accordance with <i>SOP HLD.22 Application of Cathodic Protection Criteria</i> , DOCUMENT in form D.15.A Cathodic P/S Survey Analysis, and INITIATE necessary remedial work as described in <i>SOP HLD.40 Corrosion Control Remedial Action</i> .



NOTE: Verify continuity between tank and riser.
Structure-to-reference measurements at the tank perimeter are not indicative of the CP level of the tank exterior floor surface where a nonconductive secondary containment liner is installed

**8.0
Documentation
Requirements**

Record data in electronic database or utilize the following form(s) as applicable:

- D.15.A Cathodic P/S Survey Analysis
- Corrosion database
- LPA Tracker

**9.0
References**

HLD.03 Structure-to-Electrolyte Potential Measurement
HLD.40 Corrosion Control Remedial Action

**Appendix A:
OQ Task
Requirements**

The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

Task Description	OQ Task
Measure Structure-to-electrolyte Potential – AC / DC	PLOQ406
Inspect Rectifier and Obtain Readings	PLOQ408
Commission and maintain cathodic protection bonds	PLOQ409
Annual Test Point Survey	PLOQ419

Measuring IR Drop
Standard Operating Procedures
Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	Procedure No.: HLD.21	
49 CFR 195.571	<i>Effective Date:</i> 05/01/15	Page 1 of 7

1.0 Purpose This Standard Operating Procedure (SOP) describes how to measure or calculate the approximate IR drop in structure-to-electrolyte potential measurements.

2.0 Scope The scope of this SOP is to provide guidance to the Operations Personnel in the interpretation of IR drop in cathodic protection measurements.

Quantification of IR Drop is required for all interstate pipelines.

It is not necessary to measure IR drop each time a reading is recorded. IR drop measurements made at one location may be applied to other similar locations. Careful application and interpretation of any technique is required for prudent engineering judgments.

An analysis of a recent inline inspection demonstrates that when a minimum structure-to-electrolyte potential is maintained and no corrosion anomalies are detected at the site of the potential measurement, the structure-to-electrolyte potential is an adequate measure of effective corrosion control.

In most cases, cathodic protection potentials obtained in accordance with *SOP HLD.03 Structure-to-Electrolyte Potential Measurement*, or *SOP HLD.15 Close Interval Survey*, will be evaluated in accordance with *SOP HLD.22 Application of Cathodic Protection Criteria*, and the error or IR drop will be found to be insignificant.

3.0 Applicability The SOP applies to the interpretation of pipe-to-soil (P/S) potentials used in evaluating the effectiveness of cathodic protection in accordance with *SOP HLD.22 Application of Cathodic Protection Criteria*.

4.0 Frequency As required: When IR drop is considered to be significant, or as directed by the Corrosion Specialist.

5.0 Governance The following table describes the responsibility, accountability, and authority of the operations described in this SOP.

Function	Responsibility	Accountability	Authority
All Operations	Operations Personnel	Operations Personnel	Corrosion Specialist

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**6.0
Terms and
Definitions**

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	Definitions
Electrolytic IR Drop	A voltage drop caused by current flow in the soil or water between the reference electrode contact with the electrolyte and the point of measurement. It is caused by the flow of current (cathodic protection) through a resistance (electrolyte and/or coating).
IR drop	A voltage drop caused by the flow of current through a resistor.
Metallic IR Drop	A voltage drop caused by current flow on pipelines through a resistance (test leads and connections). The total Metallic IR is the sum of certain individual resistances, including: <ul style="list-style-type: none"> • Instrument test leads and connections resistances, • Reference electrode internal resistance, • Reference electrode-to electrolyte contact resistance, • Pipe metallic resistance, and • Meter internal resistance.
Pulse Generator/Waveform Analyzer	Utilizes computer technology to remove the soil IR drop from pipe-to-electrolyte potential measurements. Produces precisely timed, zero-current pulses that are read by the Waveform Analyzer, which then automatically compensates for the soil IR drop. The Waveform Analyzer display shows the “on” potential (including the IR drop) and the “off” (zero current) or IR drop-free potential.

**7.0
Measuring IR
Drop**

The following procedures are found in this section:

- Input Impedance
- Instant Off Technique
- Buried Coupons
- Side Drain Extrapolation
- Soil Tubes
- Buried Reference Electrodes

**7.1
Input
Impedance**

Operations Personnel follows the procedure below to investigate the potential for IR drop in the measurement circuit due to insufficient digital voltmeter input impedance.

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Step	Activity
1	VERIFY calibration of digital voltmeter in accordance with <i>BP B.02 Certification and Calibration of Test Instrumentation</i> .
2	VERIFY condition and length of test leads in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> .
3	VERIFY calibration, condition, and placement of reference electrode in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> .
4	MEASURE structure-to-electrolyte potentials in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> , using a variable internal impedance voltmeter such as a MC Miller LC-4.
5	VARY internal impedance of voltmeter while recording structure-to-electrolyte potential.
6	RECORD any change in structure-to-electrolyte potential as the value IR drop into the Corrosion Database.
7	ENTER the value of IR drop into the Corrosion Database.



NOTE: Digital voltmeters with an internal impedance of 10 mega-ohms will minimize current flow through the measurement circuit in most instances, causing metallic IR to be negligible.

7.2
Instant Off
Technique

Operations Personnel follows the procedure below to measure IR drop, using current interruption.



WARNING: Follow *Safety Procedure S-090 for Electrical Safety* when working on a rectifier.

Step	Activity
1	MEASURE structure-to-electrolyte potentials in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> with all known sources of Cathodic Protection (CP) current operating at expected/historical levels.
2	SHUT OFF the sources of CP current simultaneously.



NOTE: Synchronized current interrupters are required in most pipeline applications to simultaneously shut off all sources of CP current. Refer to Section 7.2 Current Interrupted CIS of *SOP HLD.15 Close Interval Survey* for procedures detailing selection of current interrupters, interruption cycles, and synchronization of current interrupters.

Step	Activity
3	MEASURE structure-to-electrolyte potentials in accordance with <i>SOP</i>

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Step	Activity
	HLD.03 Structure to Electrolyte Potential Measurement immediately after all known sources of CP current are switched off.



NOTE:

- The error or IR drop in a structure-to-electrolyte potential will approach zero as the cathodic protection current approaches zero.
- Instant-Off potentials closely approximate the polarized potential of a structure.

Step	Activity
4	VERIFY that all sources of CP current were switched off. INSTALL additional current interrupters and REPEAT survey, as necessary.
5	SUBTRACT current interrupted potentials readings obtained in Step 3 from current applied potentials readings obtained in Step 1 for the difference in IR drop.
6	ENTER the value of IR drop into the Corrosion Database.



NOTE:

- It is rarely possible to interrupt all current sources on a pipeline, due to such factors as long line currents, tellurics, direct connect galvanic anodes, and varying degrees of polarization on electrically continuous pipelines.
- Sufficient current interruption is achieved when one of the following conditions is met:
 - Metallic IR potentials (On and Off) indicate that at least 90% of the influencing current is interrupted, in accordance with Section 7.2 of SOP HLD.15 Close Interval Survey.
 - Current flow measurements taken in accordance with *SOP HLD.04 Line Current Flow Measurement* indicate that at least 90% of the influencing current is interrupted.

**7.3
Buried
Coupons**

Operations Personnel follows the procedure below to measure IR drop using buried coupons.

Step	Activity
1	VERIFY that the metallurgical composition of the coupon is representative of the pipeline steel.



NOTE: Custom coupon fabrication may be required to match the metallurgical composition of vintage piping systems.

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Step	Activity
2	BURY coupon at pipe depth with two leads extending above grade into an electrical box.
3	BOND one coupon lead to the pipeline.
4	MEASURE coupon-to-electrolyte potential in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> , using the second coupon lead.
5	BREAK coupon to pipeline bond and immediately MEASURE the current interrupted coupon-to-electrolyte potential.
6	SUBTRACT current interrupted potentials obtained in Step 5 from current applied potentials obtained in Step 4 for the difference in IR drop.
7	ENTER the value of IR drop into the Corrosion Database.

**7.4
Side Drain
Extrapolation**

Operations Personnel follows the procedure below to calculate the IR drop free potential at the pipe surface, using Side Drain Extrapolation (SDE).

Step	Activity
1	MEASURE structure-to-electrolyte potentials in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> with the reference electrode placed directly over the pipeline.
2	MEASURE the pipeline depth at the reference cell location.
3	MEASURE structure-to-electrolyte potentials in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> with the reference electrode placed approximately 10 feet perpendicular to the pipeline.
4	MEASURE the distance from the pipeline centerline to the perpendicular reference electrode.
5	<p>CALCULATE the SDE potential using the following equation:</p> $SE_{SDE} = [SE_{PIPE} - (SE_{SIDE} - SE_{PIPE})] / [(D_{SIDE}^2 + D_{PIPE}^2)^{0.5} - D_{PIPE}] * D_{PIPE}$ <p>Where:</p> <p>SE_{SDE} = IR free structure-to-electrolyte potential (in volts) at pipe surface SE_{PIPE} = Structure-to-electrolyte potential (in volts) at over pipe (Step 1) SE_{SIDE} = Structure-to-electrolyte potential (in volts) perpendicular to pipe (Step 3) D_{SIDE} = Distance (inches) from CL of pipe to perpendicular electrode (Step 4) D_{PIPE} = Depth of pipe in inches (Step 2)</p>
6	SUBTRACT the calculated SDE potential from the surface potential measured in Step 1 for the difference in IR drop.
7	ENTER the value of IR drop into the Corrosion Database.

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<p>NOTE:</p> <ul style="list-style-type: none"> • SDE potential calculations are based on the assumption that the vertical IR drop component is proportional to the horizontal IR drop component. • SDE potential calculations are only valid for bare and poorly coated pipelines. • SDE potential calculations should not be used in multiple line right-of-ways.

7.5
Soil Tubes

Operations Personnel follows the procedure below to measure IR drop using soil tubes.

Step	Activity
1	CONSULT with environmental services prior to installation of soil tubes in areas where regulated materials are handled or stored.
2	EXCAVATE to structure/electrolyte interface and INSTALL a PVC tube.
3	INSTALL tube adjacent to buried structure to allow for placement of a reference electrode as close as possible to the structure being monitored.
4	EXTEND soil tubes above grade.
5	DO NOT place backfill inside the soil tube.
6	MEASURE structure-to-electrolyte potentials in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> with the reference electrode placed inside the soil tube that is adjacent to the structure.



<p>NOTE: Potentials taken through soil tubes will minimize but not eliminate electrolytic IR drop.</p>

Step	Activity
7	MEASURE structure-to-electrolyte potentials in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> with the reference electrode placed directly over the pipeline.
8	SUBTRACT potential measured in Step 2 from surface potential measured in Step 3 for the difference in the IR drop.
9	CAP soil tubes when not in use to prevent filling with trash.
10	ENTER the value of IR drop into the Corrosion Database.

7.6
Buried
Reference
Electrodes

Operations Personnel follows the procedure below to measure IR drop using buried, permanent reference electrodes.

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Step	Activity
1	EXCAVATE to structure-to-electrolyte interface and INSTALL permanent reference electrode adjacent to the structure.
2	INSTALL leads in an above-grade electrical box.
3	MEASURE structure-to-electrolyte potentials in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> with a portable reference electrode placed directly over the structure.
4	MEASURE structure-to-electrolyte potentials in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> , using the buried permanent reference electrode.



NOTE: Potentials taken using permanent reference electrodes will minimize but not eliminate electrolytic IR drop.

Step	Activity
5	SUBTRACT potentials measured in Step 3 from surface potentials measured in Step 2 for the difference in IR drop.
6	ENTER the value of IR drop into the Corrosion Database.

**8.0
Documentation
Requirements**

Record data in the electronic database or utilize the following form(s) as applicable:

- Corrosion Database

**9.0
References**

BP B.02 Certification and Calibration of Test Instrumentation
HLD.03 Structure-to-Electrolyte Potential Measurement
HLD.04 Line Current Flow Measurement
HLD.15 Close Interval Survey
HLD.22 Application of Cathodic Protection Criteria
Safety Procedure S-090 Electrical Safety

**Appendix A:
OQ Task
Requirements**

The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

Task Description	OQ Task
Structure-to-Electrolyte Potential Measurements	PLOQ406



Application of Cathodic Protection Criteria

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

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1.0 Purpose This Standard Operating Procedure (SOP) establishes the requirements for achieving adequate cathodic protection (CP).

2.0 Scope This SOP provides technical guidance for the application of cathodic protection criteria. Meeting any of the criterion or combination of criteria in this SOP is evidence that adequate cathodic protection has been achieved.

3.0 Applicability This SOP applies to all buried or submerged metallic assets. Metallic tank bottoms in contact with soil are also subject to the requirements of this SOP.

4.0 Frequency As Needed: Review all structure-to-electrolyte potentials to determine whether adequate CP is provided to company assets.

5.0 Governance The following table describes the responsibility, accountability, and authority of the operations described in this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	Definitions
Cathodic Polarization	The shift in potentials from the native potential as a result of the application of cathodic protection current.
Criteria	Plural of criterion (i.e., Standards, rules, or tests on which a judgment or decision can be based).
Criterion	A standard, rule, or test on which a judgment or decision can be based.
Instant-Off Potential	A structure-to-electrolyte potential taken immediately after CP current is interrupted. Instant-off potentials closely approximate the polarized potential of a structure.

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Terms	Definitions
Native Potential	A structure-to-electrolyte potential taken prior to the application of cathodic protection. Also known as a free corrosion or zero current flow potential.
ON Potential	A structure-to-electrolyte potential taken with CP current sources operational. Also known as a current applied potential.
Polarized Potential	A structure-to-electrolyte potential that is the sum of the native potential and the cathodic polarization.

**7.0
Application of
Cathodic
Protection
Criteria**

Use the following steps to determine the adequacy of cathodic protection:

- Reference electrodes
- Special conditions
- Polarized potential criterion
- 100mV polarization criterion
- -850 mV ON Legacy Criterion
- Remedial action
- Reporting forms

**7.1
Reference
Electrodes**

Use the copper/copper sulfate electrode (CSE) as the standard reference to determine adequacy of cathodic protection. Convert potentials collected using any other reference electrodes to the equivalent CSE value.

Step	Activity
1	CONVERT silver/silver chloride reference electrode potentials to the equivalent CSE potential by adding -0.05 volts to the silver/silver chloride potential value.
2	CONVERT zinc reference electrode potentials to the equivalent CSE potential by adding -1.1 volts to the zinc potential value.
3	CONSULT Corrosion Specialist for conversion values for reference electrodes other than zinc or silver/silver chloride.



NOTE: Alternate metallic reference electrodes to include zinc and/or buried steel coupons can only be used when the potential stability of the electrode is assured and voltage equivalent to a CSE is established.

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**7.2
Special
Conditions**

Notify Operations Personnel when any of the following conditions are suspected to cause cathodic protection systems to be ineffective:

- Elevated temperatures
- Acid environments
- Disbonded coatings
- Thermal insulating coatings
- Shielding
- Bacterial attack
- Dissimilar metals
- Unusual contaminants in the electrolyte
- Dynamic stray currents



NOTE: Special conditions may require additional testing to verify adequate levels of cathodic protection. Such testing includes, but is not limited to installation of corrosion coupons; direct visual examination of the piping; in-line inspection; net protective current testing; use of potential recording instruments, etc.

**7.3
Polarized
Potential
Criterion**

The Responsible Party uses the following procedures when applying the Polarized Potential Criterion.



CAUTION: Use the Polarized Potential Criterion when influencing CP current sources can be isolated from the pipeline. Consult Corrosion Specialist to determine whether this criterion can be used in areas where galvanic anodes are connected directly to the pipeline or in areas subject to stray currents.

Step	Activity
1	MEASURE On and instant-off potentials with respect to a CSE contacting the electrolyte in accordance with <i>SOP D.03 Structure to Electrolyte Potential Measurement</i> or <i>SOP D.15 Close Interval Survey</i> .
2	CONVERT potentials not obtained with a CSE to the CSE equivalent.
3	ENTER On and instant-off potentials with respect to a CSE in the corrosion database
4	For -850 mV Instant Off Potential Criteria, DETERMINE whether a (cathodic) polarized potential of at least -850 mV with respect to a CSE in contact with the electrolyte is measured, providing evidence of cathodic protection. For pipelines coated with Bucote coating systems determine whether a negative (cathodic) polarized potential of at least -900 mV with respect to a CSE in contact with the electrolyte is measured providing evidence of cathodic protection,



NOTE: Polarized potentials are most often obtained by interrupting cathodic protection current. Company procedures for obtaining polarized potentials

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using current interruption are designed to minimize voltage drops other than those across the structure-to-electrolyte boundary.

**7.3.1
Additional
Considerations**

Consider use of the 100 mV polarization criterion if structure-to-electrolyte potentials do not meet the Polarized Potential Criterion.

**7.4
100 mV
Polarization
Criterion**

Operations Personnel measures the formation or decay of cathodic polarization when applying the 100 mV Polarization Criterion.

The Formation of Cathodic Polarization Method is most commonly used for new structures prior to the application of cathodic protection.

The Decay of Cathodic Polarization Method is most commonly used for structures receiving cathodic protection.



CAUTION: Use the 100 mV polarization criterion when influencing CP current sources can be isolated from the pipeline. Consult the Corrosion Specialist/Supervisor to determine whether the 100 mV Polarization Criterion can be used in areas where galvanic anodes are connected directly to the pipeline or in areas subject to stray currents.

**7.4.1
Formation of
Cathodic
Polarization**

Adhere to the following steps for the formation of cathodic polarization method.

Step	Activity
1	MEASURE native potentials with respect to a CSE contacting the electrolyte prior to the application of cathodic protection in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> or <i>SOP HLD.15 Close Interval Survey</i>



NOTE: Potentials recorded prior to the application of cathodic protection may not represent native potentials if any section of the structure is electrically continuous with cathodically protected facilities or is subject to stray currents. Consult the Corrosion Specialist to determine whether the decay of polarization method would be more appropriate when these conditions are found.

Step	Activity
2	ENERGIZE the cathodic protection system and allow sufficient time for the formation of cathodic polarization.

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NOTE: Sufficient cathodic polarization may take several hours, days, or weeks. Consult the Corrosion Specialist for appropriate interval and / or additional testing to determine when polarization has occurred.

Step	Activity
3	MEASURE on and instant-off potentials with respect to a CSE in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> or <i>SOP HLD.15 Close Interval Survey</i>
4	CONVERT potentials not obtained with a CSE to the CSE equivalent.



NOTE: Instant-off potentials are obtained by interrupting cathodic protection current. It is rarely possible to interrupt all current on the pipeline due to long line currents, telluric, direct connect galvanic anodes, etc. Company procedures for obtaining instant-off potentials using current interruption are designed to minimize voltage drops other than those across the structure-to-electrolyte boundary. The 100 mV Polarization Potential Criterion should not be used when specifications for current interruption cannot be met.

Step	Activity
5	COMPLETE test when stable polarization has occurred and instant-off potential exceeds the native potential by 100 mV, providing evidence of CP. 200 mV in the case of Bucote coating systems.



NOTE: Cathodic protection is achieved when a minimum of 100 mV polarization formation is measured between the structure and electrolyte. For Bucote coated pipelines cathodic protection is achieved when a minimum of 200 mV polarization is measured between the structure and electrolyte.

**7.4.2
Decay of
Cathodic
Polarization**

Adhere to the following steps for the decay of cathodic polarization method.

Step	Activity
1	MEASURE on and instant-off potentials with respect to a CSE contacting the electrolyte in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> or <i>SOP HLD.15 Close Interval Survey</i> .



NOTE: Instant-off potentials are obtained by interrupting cathodic protection current.. Company procedures for obtaining instant-off potentials using current interruption are designed to minimize voltage drops other than those across the structure-to-electrolyte boundary. The 100 mV Polarization Potential Criterion should not be used when specifications for current interruption cannot be met.

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Step	Activity
2	DE-ENERGIZE or DISCONNECT all influencing cathodic protection current sources including rectifiers, galvanic anodes, bonds, current switches, etc.



NOTE: Coordinate de-energizing and/or disconnection of current sources with all parties that may be impacted (i.e., operators of foreign lines).

Step	Activity
3	MEASURE the decay of cathodic polarization by recording structure-to-electrolyte potentials at periodic intervals with all influencing current sources de-energized/disconnected. USE recording voltmeters or data loggers for measuring polarization decay to ensure that the pipeline has gone through the entire depolarization curve.



NOTE: The time required to obtain depolarization may be several hours, days, or weeks. Consult with the Corrosion Specialist to determine appropriate monitoring interval. Monitoring interval should not exceed one week.

Step	Activity
4	If significant time has elapsed between measurement of the instant off and depolarized potentials, VERIFY no adverse environmental changes have occurred, such as extremely dry or wet conditions affecting the soil moisture content at pipe depth.
5	END the test when the structure-to-electrolyte potentials recorded with all influencing current sources de-energized and disconnected, has completed the depolarization curve, and/or are at least 100 mV less than the polarized potential recorded at the beginning of the 100 mV polarization decay test. This would be 200 mV less than the polarized potential on Bucote coated pipelines.



NOTE: Cathodic protection is achieved when a minimum of 100 mV polarization decay is measured between the structure and electrolyte or 200 mV on Bucote coated pipelines.

Step	Activity
6	RE-ENERGIZE / RECONNECT all sources of cathodic protection current.

7.5
850 mV ON
Legacy
Criterion

Operations Personnel uses the following procedures when applying the 850mV ON Legacy Criterion.

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Step	Activity
1	MEASURE ON potentials with respect to a CSE contacting the electrolyte in accordance with <i>SOP HLD.03 Structure to Electrolyte Potential Measurement</i> or <i>SOP HLD.15 Close Interval Survey</i> .
2	CONVERT potentials not obtained with a CSE to the CSE equivalent.
3	CONSIDER the significance of IR drops other than those across the structure-to-electrolyte boundary.



NOTE: All structure-to-electrolyte potentials will contain error due to IR drop. IR drop is not considered significant when operational and/or historic data indicates no ongoing corrosion activity. The significance of IR drops can be considered as follows:

- Compare historical levels of cathodic protection with physical evidence from the pipeline to determine whether corrosion has occurred.
- Compare soil corrosiveness with physical evidence from the pipeline to determine whether corrosion has occurred.
- Obtain physical evidence of corrosion from leak history, pipe inspection reports, and/or ILI data.

IR drop can also be measured in accordance with *SOP HLD.21 Measuring IR Drop*

Step	Activity
4	ADJUST structure-to-electrolyte potentials to account for significant voltage drops (other than voltage drops across the structure-to-electrolyte boundary).



NOTE: No adjustment is required if voltage drops are determined to be insignificant.

Step	Activity
5	DETERMINE whether CP is achieved using the 850 mV ON Legacy criterion.



NOTE: Cathodic protection is achieved when a negative (cathodic) potential of 850 mV (with respect to a CSE) is measured with cathodic protection current applied.

Step	Activity
6	CONSIDER use of the 100 mV polarization criterion if structure-to-electrolyte potentials do not satisfy the 850 mV ON Legacy criterion.

**7.5.1
Alternative
Criterion**

Consider use of the 100 mV polarization criterion in Section 7.4 if structure-to-electrolyte potentials do not meet the 850 mV ON Legacy criterion.

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7.6 Remedial Action If acceptable levels of cathodic protection cannot be demonstrated by at least one of the cathodic protection criterion, take prompt remedial action to perform further testing and evaluations that result in adequate levels of cathodic protection. Refer to *SOP HLD.40 Corrosion Control Remedial Action*.

7.7 Reporting Forms Adhere to the following steps for reporting.

Step	Activity
1	MAINTAIN potential readings at test stations required to support the Polarized potential criterion, and, 100 mV polarization, and the 850 mV ON legacy criterion in the Corrosion database. Records INCLUDE , but are not limited to, ON potentials, polarized potentials, native potentials, static potentials, and target potentials.
2	MAINTAIN hard copy and/or electronic records of close interval survey(s) used to establish the 100 mV polarization criterion.
3	DOCUMENT any potentials not meeting criteria in the Corrosion Database, and the LPA Tracker, and appropriate forms.

8.0 Documentation Requirements Record data in electronic database or utilize the following form(s) as applicable:

- Corrosion database
- EAM
- LPA Tracker

9.0 References
HLD.03 Structure to Electrolyte Potentials
HLD.15 Close Interval Survey
HLD.20 Annual Corrosion Control Surveys
HLD.21 Measuring IR Drop
HLD.40 Corrosion Control Remedial Action

Appendix A: OQ Task Requirements There are no Operator Qualification (OQ) tasks required for this SOP

Induced AC Measurement and Mitigation

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	Procedure No.: HLD.23	
49 CFR 195.577	Effective Date: <i>04/01/18</i>	Page 1 of 5

1.0 Purpose This Standard Operating Procedure (SOP) describes how to perform alternating current (AC) induction measurements and mitigation efforts. In some cases, measurement of Pipe-to-soil (P/S) AC voltages is required to be measured at the same time corrosion structure-to-soil potentials are taken. Other situations require AC Pipe-to-soil potentials only to be taken when their presence is suspected. This may take the form of a special survey to investigate these effects.

2.0 Scope Induced AC on pipelines in common rights-of-way (ROW) with high voltage AC power lines can cause a shock hazard, irregular readings during measurement of Cathodic Protection (CP) voltages, and interference-type corrosion. AC induction measurements provide proof of induced AC, and mitigation techniques can then be applied.

3.0 Applicability This SOP is applicable to buried steel piping that may have AC induction concerns.

4.0 Frequency Measure pipe-to-soil AC readings annually in conjunction with annual cathodic protection surveys conducted in accordance with *SOP HLD.20 Annual Corrosion Control Surveys*, at locations where induced AC is known or suspected to exist.

Remediate any AC readings greater than 15 volts in accordance with *SOP HLD.40 Corrosion Control Remedial Action*.

5.0 Governance The following table describes the responsibility, accountability, and authority for this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	Definitions
Voltage Gradients	Differences in voltage from point-to-point in the earth, which can cause interference effects on foreign structures and may create safety hazards to personnel.

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**7.0
Induced AC
Measurement
and Mitigation**

The following procedures are found in this section:

- Voltage Gradients
- Safety Considerations During Measurement
- Mitigative Techniques
- Structure-to-Structure AC Measurement
- AC P/S Measurement

**7.1
Voltage
Gradients**

High voltage AC or direct current (DC) electrical transmission lines, lightning strikes, or a temporary ground fault from electrical transmission or distribution systems can induce voltage gradients (step and touch potentials). The magnitude of the current, the resistivity of the earth, and the voltage of the source affect the voltage gradient.

Three areas of concern resulting from induced AC voltages are:

- Shock hazard
- Measurement nuisance
- Interference-type corrosion

Prior to measurement and mitigation, the Operations Personnel checks for the following.

Step	Activity
1	IDENTIFY sites with exposure to high voltage electric transmission lines where power lines are parallel and in the ROW.
2	For those sites, CHECK where the power line diverges from the pipeline.
3	CHECK for possible hazards, which could include: <ul style="list-style-type: none"> • Pipelines with any common ROW with high voltage transmission lines. • Pipelines in close proximity to electric switching stations or generating stations. • Pipelines located near electric system steel tower footings, buried electric ground wires, or other buried metallic structures connected to the electric ground system.



NOTE: Corrosion damage from induced AC on older pipelines is unlikely. AC corrosion may be a concern on newer pipelines with coating systems such as extruded PE and FBE. Damage as the result of lightning is usually a result of “arcing” or “melting” of the metal. A high current flow in a pipeline caused by lightning or fault currents can cause pipe wall penetration and insulator destruction.

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**7.2
Safety
Considerations
During
Measurement**

The Operations Personnel follows this procedure to reduce the risk of shock hazard when pipeline corrosion testing is necessary.

Step	Activity
1	USE well-insulated test leads with insulated clip connectors when making test connections to pipe.
2	AVOID contacting the pipe structure with one hand while contacting any grounded structure with the other hand.
3	WEAR well-insulated footwear, and always STAND on well-drained, dry soil while taking measurements on the pipeline.
4	AVOID simultaneously contacting pipe on both sides of an insulating flange or fitting in the pipeline.
5	Whenever making or breaking electric bond connections between the pipe and grounded structure, always MAKE the first and last connection while holding the grounded connection.

**7.3
Mitigative
Techniques**

The Operations Personnel follows the procedure below for mitigative techniques.

Step	Activity
1	CONTROL the induced AC voltages on pipelines through installation of mitigative measures, where applicable.
2	Whenever structure-to-soil AC voltages are found to be greater than 15 volts, INITIATE consultation with the Corrosion Specialist detailing field conditions. Consider mitigation accordance to the guidelines in the table below.

Table 1: Mitigation Guidelines

AC S/S	Personal Protection	Equipment Protection
0 – 15	None	Active/Passive Filters
16 – 30	Ground Cells	Passive Filters
> 30	Ground Cells/Eliminate Source	Avoid Measurements



NOTE:

- Remedial Action recommendations will be developed by the Corrosion Technician with assistance from outside contractors or the Corrosion Technical Services Group as required.
- Potential remedial actions include grounding of the pipeline with a continuous zinc ribbon anode or a series of galvanic grounding beds and a solid state

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decoupler(s). These systems are designed to reduce the induced voltages to acceptable limits and reduce the shock hazard.

Step	Activity
3	INSTALL test stations with “dead front” design to prevent contact with exposed terminals.
4	RECORD all remedial action on <i>form D.40.A for Corrosion Control Remedial Action Report</i> in accordance with <i>SOP HLD.40, Corrosion Control Remedial Action</i> .

**7.4
Structure-to-
Structure AC
Measurement**

The Operations Personnel follows the procedure below for structure-to-structure AC measurement.

Step	Activity
1	MEASURE a structure-to-structure AC voltage (e.g., test station to fence) by selecting the appropriate AC scale of a digital voltmeter. CONNECT one lead to each of the structures.
2	DOCUMENT readings in the Corrosion Database.

**7.5
AC P/S
Measurement**

The Operations Personnel follows the procedure below for AC pipe-to-soil (P/S) measurement.

Step	Activity
1	MEASURE the AC P/S (pipe-to-soil) using the appropriate AC scales of a digital voltmeter. ATTACH one lead to the structure and the other to a copper/copper sulfate reference electrode.
2	DOCUMENT readings in the Corrosion Database.

**8.0
Documentation
Requirements**

Record data in electronic database or utilize the following form(s) as applicable:

- Corrosion Database
- D.40.A Corrosion Control Remedial Action Report

**9.0
References**

HLD.20 Annual Corrosion Control Surveys
HLD.40 Corrosion Control Remedial Action

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**Appendix A:
OQ Task
Requirements**

Task Description	OQ Task
Structure-to-Electrolyte Potential Measurements	PLOQ406



Cathodic Protection System Design

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference:	Procedure No.: HLD.25	
49 CFR: 195.563	<i>Effective Date:</i> 04/01/18	Page 1 of 26

1.0 Purpose This Standard Operating Procedure (SOP) describes requirements for design of galvanic and impressed current cathodic protection systems.

2.0 Scope Cathodic protection is required to be installed on all buried or submerged metallic assets to include breakout tank bottoms in contact with the soil. This SOP covers the design and installation, and inspection of galvanic and impressed current cathodic protection systems.

3.0 Applicability This SOP applies to buried or submerged metallic assets to include breakout tank bottoms in contact with the soil.

4.0 Frequency As required when any of the following conditions are found to exist:

- Within one year of in service date of construction of new facilities
- Depletion of existing cathodic protection systems
- Low potential areas
- Special Conditions where supplemental CP is required

5.0 Governance The following table describes the responsibility, accountability, and authority for this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	Definitions
Conventional Remote Anode Ground Bed	An anode bed that is augured or trenched in place, where the anodes are placed either vertically or horizontally at a depth from 5 to 50 feet.

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Terms	Definitions
Deep Remote Anode Ground Bed	An anode bed that is drilled into place vertically to a depth greater than 50 feet
Distributed Anode Bed	Use these beds to effectively protect a network of piping and geometrically complex structures, such as those found at pump stations, tank farms, pipeline terminals, refineries, and in urban areas. The anodes of the bed are distributed at various points and often in a non-geometric pattern in order to overcome the shielding effect of one structure by another.
Electrically Remote	A point where movement of a reference electrode results in no or an insignificant shift in structure to electrolyte potential

**7.0
Cathodic
Protection
System Design**

The following procedures are found in this section:

- Current Requirement for Cathodic Protection
- Methods of Applying Cathodic Protection
- Installation of Galvanic Anodes
- Impressed Current Systems
- Impressed Current Groundbed Selection
- Calculate Anode Bed Resistance and Size Impressed Current Power Source



NOTE:
<ul style="list-style-type: none"> • Design anode installations for a minimum life of 20 years when the structure to be protected is permanent. • For offshore pipelines or other inaccessible structures, it is common to design anode systems for 30 to 40 years.

**7.1
Current
Requirement
for Cathodic
Protection**

Operations Personnel follows the procedures below to determine current required to obtain cathodic protection.



NOTE:
Calculated cathodic protection current requirements are useful to verify field test results and estimate cathodic protection requirements for new facilities.

Step	Activity
1	To obtain a measured value of the current requirement, PERFORM testing in accordance with <i>BP D.16 Current Requirement Testing</i> .

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Step	Activity
2	To calculate the current requirement, OBTAIN the exposed surface area and the current density.
3	If the conditions of the pipe coating are known, ESTIMATE the required cathodic protection current density using Table 1: Current Requirements vs. Soil Resistivity or Appendix D: Current Requirements.
4	To obtain the current density using Table 1, MEASURE soil resistivity in accordance with <i>SOP HLD.06 Soil Resistivity Measurement</i> .
5	If measuring soil resistivity, CONSIDER seasonal variations when making this determination. SELECT a higher current density where any of the following conditions exist: <ul style="list-style-type: none"> • Elevated bacteria levels are confirmed in the electrolyte • pH levels < 5 • Chloride levels > 20,000 ppm • Elevated temperatures with respect to the balance of buried or submerged piping • Polarization degradation from moving water • Modified butadiene styrene coating systems (Bucote) USE a design current density (DCD) of 2 mA/ft ² and assume 20% bare steel on Bucote coated pipeline segments.

Table 1: Current Requirements vs. Soil Resistivity

Electrolyte	Milliamperes/ft ² Required
Very high resistivity soils	0.10 to 0.50
Normal soils	0.5 to 3.0
Seawater, fresh water, and extremely low resistivity soils	3 to 40

Step	Activity
6	To obtain the current density using Appendix D, ESTIMATE the area of bare steel that is exposed to the electrolyte. CONSIDER the effect of coating degradation over the life of the system.
7	To obtain the exposed surface area: USE data gathered from current requirement testing and soil resistivity data in conjunction with Table 1. Or ESTIMATE Bare Surface Area: For new pipe, SELECT 0.5% – 1.0% of exposed surface area. For vintage pipe, SELECT 5% - 100% of exposed surface area. For tank bottoms, SELECT 100% of surface area.
8	CALCULATE the cathodic protection current requirement using the following formula:

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Step	Activity
	Current Required = Exposed Surface Area X Current Density
9	COMPARE calculated vs. measured current required. SELECT the highest value.



NOTE: Verify that electrical inter-connects between parallel pipelines are adequate during current requirement testing using above grade jumpers. If installation of above grade jumpers significantly changes potentials on parallel lines, consult the Corrosion Specialist to determine whether additional interconnect cables and/or dedicated rectifier negatives are required.

**7.2
Methods of
Applying
Cathodic
Protection**

The Operations Personnel follows the procedure below to determine the most effective means of applying cathodic protection.

Step	Activity
1	USE one of the two proven methods to apply CP to underground or submerged metallic structures: <ul style="list-style-type: none"> • Galvanic or sacrificial anodes • Impressed current or rectifier-anode beds



NOTE: With both methods, a DC current supply is made available for the protection of a buried or submerged structure.

Step	Activity
2	SELECT the method based on economic and technical considerations, as each has advantages and disadvantages. REVIEW the selection with the Corrosion Specialist.
3	CONSIDER using galvanic anode cathodic protection systems: <ul style="list-style-type: none"> • On Pipelines or laterals where it is more economical than impressed current • On Localized cathodic protection on bare or poorly coated pipelines • On Submerged pipelines (bays and inlets) • Where stray or fault current drainage exist <p>In conjunction with solar-powered systems to reduce the reverse EMF effect</p>
4	CONSIDER using impressed currents when there is an external source for applying cathodic protection to underground or submerged metallic structures.

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Step	Activity
5	DO NOT MIX galvanic and impressed current systems unless directed by the Corrosion Specialist



NOTE:

- Where possible, do not mix galvanic and impressed current systems.
- **Do not** connect galvanic anode systems directly to the pipeline, except when bracelet or structural anodes are installed offshore.

**7.2.1
Galvanic
Anodes**

Operations Personnel uses galvanic anode cathodic protection systems in the following situations:

- Pipelines or laterals where it is more economical than impressed current.
- Localized cathodic protection on bare or poorly coated pipelines.
- Stray or fault current drainage.
- Use in conjunction with solar powered systems to reduce the reverse EMF effect.
- On submerged pipelines (offshore, bays, and inlets)

**7.2.2
Calculate
Galvanic Anode
Life**

Use the appropriate formula below to determine the life expectancy of a given weight anode or the anode weight necessary for desired life at known current outputs assuming complete consumption of anodes.

$$L_m = \frac{42.81 W}{I} \quad L_z = \frac{28.68 W}{I} \quad L_a = \frac{98.32 W}{I}$$

Where:

- L_m = life of magnesium anode, years
- L_z = life of zinc anode, years
- L_a = life of aluminum anode (indium), years
- W = weight of anode, pounds
- I = milliamperes output of anode



NOTE:

- Anode current output is obtained from current requirement testing or calculations.
- Design anode installations for a minimum life of 20 years when the structure to be protected is permanent.
- Equations should be used to determine the total weight of galvanic anodes required, using specified design life and required current output. In most pipeline applications, the required weight of anode material will make impressed current systems more economical.

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<ul style="list-style-type: none"> Constants given above (42.81, 28.68, and 98.32) are based on 75% of the theoretical current efficiencies for each anode type using Faraday’s Law, as 100% anode consumption will not occur due to lead failure. Anode life can be calculated using theoretical current efficiencies as follows: $L_m = \frac{57.08 \text{ W}}{I} \quad L_z = \frac{38.24 \text{ W}}{I} \quad L_a = \frac{131.09 \text{ W}}{I}$ Constant anode output has also been assumed whereas such factors as soil moisture and ground temperature will cause variable output. Also, as anodes are consumed, the current output will be lower due to reduced anode dimensions.

**7.2.3
Calculate
Galvanic Anode
Current Output**

Operations Personnel follows the procedure below for determining delivered current.

Step	Activity
1	CONSIDER the current the galvanic anodes will deliver for the protection of the structure when designing an anode bed.
2	<p>DETERMINE the current output of galvanic anodes through these principle controlling factors:</p> <ul style="list-style-type: none"> The size and coating condition of the structure to be protected The resistivity of the soil or electrolyte surrounding the anode The size and shape of the anode (including backfill) The metallurgical formulation of the anode The kind and amount of backfill used Distance of the anode from the structure to be protected Depth at which the anode is buried The number of anodes and their spacing The pipe-to-soil potential of the structure
3	<p>USE the following empirical formulas to estimate current output of standard dimension galvanic anodes.</p> $i_m = \frac{120,000 \text{ fY}}{P} \quad i_z = \frac{40,000 \text{ fY}}{P} \quad i_a = \frac{50,000 \text{ fY}}{P}$ <p>Where: <i>i_m</i> = current output for magnesium anode, milliamperes <i>i_z</i> = current output for zinc anode, milliamperes <i>i_a</i> = current output for aluminum alloy anode, milliamperes P = soil resistivity, ohm-centimeters f = factor from Table 1 of Appendix B</p>

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Step	Activity
	Y = correction factor for resultant pipe-to-soil potential values from Table 2 of Appendix B
4	ADJUST calculated anode current output using the factors provided in Table 3 of Appendix B when multiple anodes are installed in parallel.



NOTE:

- Formulas assume 10 foot spacing between anode and structure, soil resistivity greater than 500 ohm-centimeters, and that structure that is effectively coated.
- Current outputs for galvanic anodes connected to bare or poorly coated pipelines are higher than those for anodes connected to well-coated pipelines, particularly in lower resistivity soils, as the structure-to-earth resistance of a bare structure is lower than the structure-to-earth resistance of a well-coated structure and must be considered in the total resistance of the circuit.
- Adjust the formulas as follows for bare or poorly coated structures:

$$i_m = \frac{150,000 fY}{1. P} \quad i_z = \frac{50,000 fY}{P} \quad i_a = \frac{62,000 fY}{P}$$

7.2.4

Galvanic Anode Selection

Operations Personnel follows the procedure below for the selection of galvanic anode systems

Step	Activity
1	REVIEW the galvanic anode selection with the Corrosion Specialist.
2	USE the type of galvanic anode for cathodic protection based on environmental and economic considerations: <ul style="list-style-type: none"> • Magnesium: A higher driving potential, delivers greater currents, consumed more rapidly, consumed 2.5 times faster than zinc in a given soil resistivity environment • Zinc: Generally more economical where soil resistivities are below 1,000 ohm-cm, provided that the current requirement for protection is not too high and the desired current output can be obtained • Aluminum: Generally more economical than zinc or magnesium where electrolyte resistivities are below 100 ohm-cm, usually restricted to offshore and brackish water applications
3	EVALUATE the economic feasibility of galvanic anodes based on the weight of the anode material required vs. the economics of the installation of an impressed current system.



NOTE:

- Various grades of galvanic anodes are available.

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- Higher grade zinc and magnesium anodes are generally more expensive but have higher driving voltages and generally provide longer service life. Consult your Corrosion Specialist prior to making galvanic anode selection.
- Grades of aluminum anodes are generally related service applications, not purity of alloys.

**7.3
Installation of
Galvanic
Anodes**

Operations Personnel follows the procedure below for installation of galvanic anodes.

Step	Activity
1	CONSULT Environmental Specialist to determine if any special conditions exist in proposed location of anode installation.
2	INSTALL galvanic anodes individually or in multiple anode banks. Multiple anodes can be installed either parallel or perpendicular to the pipeline.
3	Where necessary, INSTALL anodes in an open ditch during pipeline construction parallel to the structure.
4	DETERMINE the anode configuration, spacing, and distance to the pipeline using the following factors: <ul style="list-style-type: none"> • Length and diameter of the pipe to be protected • Soil resistivity • Condition of coating • Type of anodes employed • Availability of easement
5	CONNECT anode lead wire aboveground in a receptacle using an appropriate shunt (usually 0.01 ohm) in the circuit to permit measurement of the current output DO NOT CONNECT galvanic anode systems (including AC mitigation systems) directly to the pipeline unless directed by the Manager of Corrosion Services.



- NOTE:**
- Spacing will depend on soil condition and quality of coatings. The closer the anodes are to the structure, the lower the circuit resistance, which results in a greater current output. However, the current distribution is restricted.
 - The further anodes are from the structure (as in a perpendicular installation), the higher the circuit resistance and the lower the current output. However, a greater distribution of protective current is realized.
 - Anode lead wire connections must be made aboveground in a receptacle using an appropriate shunt (usually 0.01 ohm) in the circuit to permit measurement of the current output.

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**7.4
Impressed
Current
Systems**

Impressed current systems (rectifier-anode beds) use an AC or DC power source and one of these three types of ground beds for cathodic protection:

- Conventional Remote Anode Beds
- Deep Remote Anode Beds
- Distributed Anode Beds

Operations personnel use the procedures that follow to select the power source and type of ground bed to use for the impressed current system. Refer to Figure 2: Typical Rectifier Anode Bed for an illustration of a typical rectifier anode bed installation utilizing an existing Alternating Current (AC) power supply.

Step	Activity
1	USE impressed currents from an external source for applying cathodic protection to underground or submerged metallic structures.
2	REFER to Figure 2 for an illustration of a typical rectifier-anode bed installation utilizing an existing AC power supply.

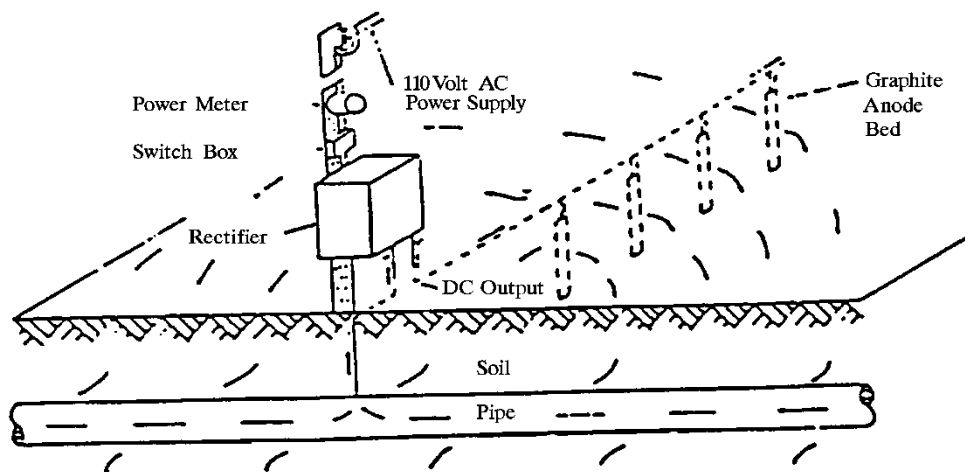


Figure 2 – Typical Rectifier Anode Bed

**7.4.1
Impressed
Current Power
Supply
Selection**

Operations Personnel follows the procedure below to select an external Direct Current (DC) power source for the impressed current system.

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Step	Activity
1	CONSIDER a full wave rectified AC power supply when AC power is readily available.
2	CONSIDER solar power if the following requirements are met: <ul style="list-style-type: none"> • There is unobstructed sunlight for the majority of the year. • There is a secure area for the solar panels, as they are often vandalized and stolen. • There is a large amount of space available to house the solar panels. • Solar panels can be secured against wind



NOTE:
<ul style="list-style-type: none"> • Adequate battery power must be available to power the CP system when sunlight is not available (e.g., night and adverse weather). • Solar panels will not operate when covered with ice and snow or shielded from direct sunlight by vegetation. • Solar panels should only be considered in secure areas, as they are often vandalized and stolen. • The size of the solar panel array is proportional to the required current output. Large amounts of space are often required to house the solar panels. • Solar panels must be secured against wind. Large panel arrays are often not feasible in high wind areas.

Step	Activity
3	CONSIDER thermoelectric power supplies or natural gas driven generators in areas where AC power cannot be obtained and solar power is not feasible.



NOTE:
<ul style="list-style-type: none"> • These systems utilize natural gas to generate DC power. • These systems are generally more expensive than AC or solar powered sources. • Thermoelectric generators are generally not feasible if higher levels of DC current are required. Consult your Corrosion Specialist.

Step	Activity
4	CONSIDER alternative DC power sources as applicable.



NOTE:
Alternative DC power sources are commercially available such as wind-powered generators or fuel cells. Consult with the Corrosion Specialist if alternative DC power sources are believed to be a viable option.

Step	Activity
5	REVIEW the final election with the Corrosion Specialist.

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7.5 Impressed Current Groundbed Selection Operations Personnel follow the procedure to determine the feasibility of deep remote anode bed, conventional remote anode bed, or distributed anode bed.

7.5.1 Conventional Remote Anode Bed Operations Personnel follows the procedure below to consider the feasibility of conventional remote anode beds.

Step	Activity
1	INSTALL these beds at a point electrically remote from the structure to be protected.
2	USE this type of anode bed where a large spread of the protective current is desired.
3	LOCATE the first anode of the anode bed 100 to 1000 feet from the pipeline or the structure being protected.



NOTE: Greater distances to the first anode are used where a pipeline is poorly coated or bare, while shorter distances suffice on well-coated structures.

7.5.2 Deep Remote Anode Bed Operations Personnel follows the procedure below to consider the feasibility of deep remote anode beds.

Step	Activity
1	<p>EMPLOY the deep anode installation when:</p> <ul style="list-style-type: none"> • Easements are a problem. • Soil resistivity limitations are encountered near the surface of the ground. • Anodic interference with foreign lines can occur when using conventional remote anode beds. • Seasonal variations in shallow soil moisture levels affect conventional remote anode bed performance.

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<p>NOTE:</p> <ul style="list-style-type: none"> • Anodes and coke backfill in a deep anode bed must installed at a point electrically remote from the pipeline. • Deep anode beds have been drilled at depths to 1,000 feet. • Consult the Environmental Specialist concerning the feasibility of a deep anode bed, as environmental regulations may restrict use of this system.

Step	Activity
2	<p>CONSIDER disadvantages of deep anode beds as follows:</p> <ul style="list-style-type: none"> • Normally more expensive to install • Most are difficult or impossible to repair when problems develop • Resistance to earth is less predictable, as surface measurements cannot accurately predict soil resistivity at anode depth. • Preliminary current requirement tests cannot be made accurately unless pilot holes are drilled and temporary anodes inserted. • Gradual increases in circuit resistances and reduced current outputs are often encountered due to gas blockage, preferential corrosion attack of anodes, high resistance anodic polarization products forming on anodes, and failure of anode connecting wires • Offsite disposal of drill cuttings and fluids may be required and must be included in cost estimates. • Subsurface conditions cannot be determined until drilling had commenced. • Consult with the Corrosion Specialist before considering installation of a deep anode bed in areas where limited knowledge is available concerning subsurface conditions.

**7.5.3
Distributed
Anode bed**

Operations Personnel follows the procedure below to consider the feasibility of distributed anode beds.

Step	Activity
1	<p>EMPLOY a distributed anode bed when any of the following conditions are encountered.</p> <ul style="list-style-type: none"> • Cathodic Shielding • Localized variations in soil resistivity • Localized variations in coating quality • Cathodic interference.

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Step	Activity
2	<p>CONSIDER disadvantages of distributed anode beds as follows:</p> <ul style="list-style-type: none"> • Often require hand excavation • Limited area of current distribution • Potential anodic interference

**7.6
Calculate
Anode Bed
Resistance &
Size Impressed
Current Power
Source**

Operations Personnel follows the procedure below to calculate anode bed to electrolyte resistance in order to size the impressed current power source.

Step	Activity
1	PERFORM soil resistivity tests in proposed anode bed locations in accordance with <i>SOP HLD.06 Soil Resistivity Measurement</i> .



NOTE: Soil tests also serve to determine the anode depths and whether the anodes are to be installed vertically or horizontally.

Step	Activity
2	DESIGN the anode bed to obtain the lowest feasible circuit resistance using the established current requirement.
3	USE one of the following empirical formulas to calculate the resistance to ground of a single or multiple vertical or horizontal anodes.
4	<p>Simplified Formula The following simplified formulas will provide estimated anode to electrolyte resistance for the following parameters:</p> <p>Vertical anode: 8-12” in diameter; 10 ft. in length Horizontal anode: 12” square in cross section; 6-10 ft. in length; 4-6 ft. deep</p> $R_v = \frac{PF}{537} \qquad R_h = \frac{PF}{483}$ <p>Where: R_v = resistance to earth of a vertical anode, ohms R_h = resistance to earth of a horizontal anode, ohms P = soil resistivity, ohm-centimeters F = adjusting factor for multiple anodes (refer to Table 3 of Appendix B)</p>

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NOTE: Anode dimensions include dimensions of the coke breeze.

Step	Activity
5	<p>The E.D. Sunde equation for resistance to earth using multiple vertical anodes is as follows:</p> $R_v = \frac{P}{191.5NL} \left[(2.303 \log \frac{4L}{a}) - 1 + (\frac{2L}{S} \times 2.303 \log 0.656N) \right]$ <p>Where: R_v = resistance to earth of vertical anodes P = soil resistivity ohm-centimeters N = number of parallel anodes L = anode length including backfill, feet a = anode radius including backfill, feet S = anode spacing, feet</p>
6	<p>The H.B. Dwight equation for resistance to earth for a single horizontal anode is as follows:</p> $R_h = \frac{0.00522P}{L} \left[(2.303 \log \frac{4L}{d}) + (2.303 \log \frac{L}{h}) + \frac{2h}{L} - 2 \right]$ <p>Where: R_h = resistance to earth of horizontal anodes P = soil resistivity ohm-centimeters L = anode length, feet d = anode diameter including backfill, feet h = depth from surface to center of anode, feet</p> <p>For the resistance to earth of multiple horizontal anodes, multiply R_h by the proper “F” adjusting factor from Table 3 of Appendix B.</p>
7	<p>After the resistance to earth of the anode bed (R_2) is determined, DETERMINE the resistance of the positive header cable of the bed (R_1) and the pipeline negative cable (R_6). REFER to Figure 6.</p>
8	<p>DETERMINE the total resistance of the positive header cable. ADD the resistance of the length of cable from the positive connection of the rectifier to the first anode to one-half the resistance of the length of cable from the first anode to the last anode.</p>
9	<p>DETERMINE the resistance of the negative cable.</p>

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NOTE: The resistance of positive and negative header cables can significantly impact groundbed performance and cathodic protection current distribution. The IR drop across all cables must be quantified and carefully considered during groundbed design.

Example:

A conventional groundbed will utilize an 800' header cable between the rectifier and the first anode. The rectifier is an 80 volt / 80 amp unit that is expected to operate at / near rated capacity. Table 4 indicates that all conductors between AWG #6 and 4/0 are rated for ≥80 Amps. As each conductor's ampacity rating exceeds the maximum rectifier current output, what is the impact of selecting a less expensive (i.e. AWG #6) header cable?

A.W.G. Gage No.	Resistance (Ω) per 1000 ft	Current Capacity (Amps)	Calculate Resistance (Ω) of 800' Header	Header Resistance (Ω)	Voltage Drop across Header at 80 Amps V = I x R	Voltage Drop in Header
0000 or 4/0	0.049	370	= (800 feet) x (0.049 Ω/1000 feet)	0.0392	= 80 x 0.0392	3.14
000 or 3/0	0.0618	320	= (800 feet) x (0.0618 Ω/1000 feet)	0.04944	= 80 x 0.04944	3.96
00 or 2/0	0.0779	270	= (800 feet) x (0.0779 Ω/1000 feet)	0.06232	= 80 x 0.06232	4.99
0 or 1/0	0.0983	240	= (800 feet) x (0.0983 Ω/1000 feet)	0.07864	= 80 x 0.07864	6.29
1	0.1239	200	= (800 feet) x (0.1239 Ω/1000 feet)	0.09912	= 80 x 0.09912	7.93
2	0.1563	175	= (800 feet) x (0.1563 Ω/1000 feet)	0.12504	= 80 x 0.125004	10.00
3	0.197	155	= (800 feet) x (0.197 Ω/1000 feet)	0.1576	= 80 x 0.1576	12.61
4	0.2485	130	= (800 feet) x (0.2485 Ω/1000 feet)	0.1988	= 80 x 0.1988	15.90
6	0.3951	95	= (800 feet) x (0.3951 Ω/1000 feet)	0.31608	= 80 x 0.31608	25.29

As shown above, selection of a #6 header cable results in a voltage drop of 25.29 volts or 31.6% of the rectifier output voltage in the 800' header cable. This equates to installation of a 54.7 volt rectifier at the first anode when operating at maximum current output.

Selection of the 4/0 cable results in a voltage drop of 3.14 volts or 3.9% of the rectifier output voltage. This equates to 76.86 volts at the first anode when operating at maximum current output.

- Cable selection is one of the easiest variables to control when designing a groundbed. Failure to consider the impact of cable size can significantly impact groundbed performance. Short term cost savings due to smaller wire sizes will result in higher electric bills (due to power loss in the cable) and decreased groundbed performance.

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Step	Activity
10	After the individual component resistance(s) have been determined, CALCULATE the total structure-to-earth resistance. ADD all the individual component resistances.
11	NEGLECT these resistances unless directed by the Corrosion Specialist: <ul style="list-style-type: none"> • Resistance of the pipeline within the span of protection except for lines smaller than 8” OD • Earth resistance • Structure-to-earth resistance • The resistance of the rectifier REVIEW all design calculations with the Corrosion Specialist.
12	REFER to Table 4 of Appendix B for ohmic values for various sizes of copper cable and wire per 1,000-foot lengths for use in calculating the resistances of the positive and negative cables.



NOTE:

- In most cases, the only component resistances that need to be considered are the anode bed to earth resistance (R₂), the positive header cable resistance (R₁) and the negative cable resistance (R₆).
- The total circuit resistance is simply:
$$R_T = R_1 + R_2 + R_6$$
 - It should be noted that if other component resistances are determined to be significant by the Corrosion Specialist, these resistances should be included in the total resistance.
- Where anode beds are designed in extremely low resistivity soils and only a few anodes are indicated by the design equation, the controlling factor for the number of anodes to install becomes the maximum allowable current output per anode.
- Most anode manufacturers recommend a certain maximum current output for an anode depending upon type and size. When this value is exceeded, the life of the anode bed is greatly reduced. For the common size anodes (3” x 60” graphite and 2” x 60” high silicon cast iron) in tamped coke breeze, a maximum of three (3) amperes per anode is a safe figure.

Step	Activity
13	SIZE the impressed current power source using the calculated total anode bed circuit resistance and cathodic protection current demand using Ohm’s law. CONSIDER additional rectifier output capacity to account for seasonal variations where additional voltage may be required to maintain protection, coating degradation, and expansion of facilities.
14	For newly constructed, coated lines SELECT the rectifier rating (amperes and volts) approximately twice the indicated design values.
15	On older coated lines, or bare or poorly coated pipelines, RATE rectifiers for operation near design values.

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Step	Activity
16	In situations where stray DC currents affect the pipeline, CONSIDER a voltage control system for the rectifier circuit.



NOTE:

- In extremely high resistivity soils, it is often difficult to calculate total anode bed circuit resistance due to unknown soil resistivities at anode depth. In such cases, it is advisable to install the anode bed first and size the rectifier after installation is complete.
- It is good practice on newly constructed, coated lines to select the rectifier rating (amperes and volts) approximately twice the indicated design values. The extra power is usually needed as the soil compacts and as the coating deteriorates or when additions are made to the new pipeline.
- On older coated lines, a factor of two is not necessary, although some extra capacity should be provided. On bare or poorly coated pipelines, rectifiers should be rated to operate near design values to achieve maximum rectifier efficiency and economy.
- In some situations where stray DC currents affect the pipeline, the rectifier circuit may include voltage control system.

**7.6.1
Anode Bed
Location
Selection**

Review the items below to assist in the selection of an anode bed site.

Step	Activity
1	CONSIDER accessibility to a rectifier site when planning an installation.
2	<p>CONSIDER these points in selection and installation:</p> <ul style="list-style-type: none"> • Selection of a properly rated, designed, and constructed rectifier • Selection of anode bed cable for proper size conductor with suitable insulation for direct burial and for cathodic protection use • Selection of type, size and correct number of anodes with consideration given to the environmental conditions and to the nature of the soil • The method of making the anode-to-header cable splice and the insulating material to use in order to achieve perfect and durable splices • Selection of proper mesh and resistivity coke breeze • Equipment to properly tamp coke breeze • Height of the coke column and distance from the top of the coke (i.e. active anode) to the pipeline • Sufficient burial depth of cables to prevent damage by plows and exposure by washes

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	<ul style="list-style-type: none"> • Proper connection of the negative cable to the structure being protected • Dedicated negative cables and/or shunt boxes to regulate current flow to each pipeline • Proper installation of the rectifier considering grounding and other safety measures • Proper connection of the positive and the negative cable to the rectifier
3	
4	COMPLETE the applicable form(s) for D.16A <i>Cathodic Protection System Design</i> and attach data shown in figure 11

<p>7.6.2 Cathodic Protection Test Station</p>	<p>See <i>Appendix</i> for typical cathodic test station design.</p> <ul style="list-style-type: none"> • Where practical, the maximum distance between onshore pipeline test points will be approximately one (1) to two (2) miles. • Test leads must be installed so as to remain mechanically secure and electrically conductive • Test leads must be attached to the pipe in a manner to prevent stress concentrations on the pipe. • Bare test lead connections to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.
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<p>NOTE: Test lead wiring must be maintained in proper condition to ensure electrical measurements are suitably achieved on buried pipelines.</p>
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**8.0
Documentation
Requirements**

Record data in electronic database or utilize the following form(s) as applicable:

- D.16.A Cathodic Protection System Design (Current Requirement Test)
- D.25.A Anode bed Justification

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- 9.0** HLD.06 Soil Resistivity Measurement
References HLD.16 Current Requirement Testing
HLD.22 Application of Cathodic Protection Criteria

Appendix A: There are no Operator Qualification (OQ) tasks required for this SOP.
OQ Task Requirements

Appendix B:
Data Tables

TABLE 1		
Anode Weight Pounds	Standard Anodes	Factor f
3	anode dimension 6" x 10" (packaged)	0.53
5	anode dimension 6" x 12" (packaged)	0.60
9	anode dimension 6" x 17" (packaged)	0.71
17	anode dimension 6½" x 29" (packaged)	1.00
32	anode dimension 8" x 28" (packaged)	1.06
50	anode dimension 10" x 24" (packaged)	1.09
50	anode dimension 8" x 38" (packaged)	1.29
Anode Weight Pounds	Long Anodes	Factor f
9	2.75" x 2.75" x 26" backfilled to 6" x 32"	1.01
10	1.5" x 1.5" x 72" backfilled to 4" x 78"	1.71
18	2" x 2" x 72" backfilled 5" x 78"	1.81
20	2.5" x 2.5" x 60" backfilled 5" x 66"	1.60
40	3.75" x 3.75" x 60" backfilled 6.5" x 66"	1.72
42	3" x 3" x 72" backfilled 6" x 78"	1.90
Anode Weight Pounds	Extra Long Anodes	Factor f
15	1.6" diameter x 10' backfilled to 6" x 10'6"	2.61
20	1.3" x 20' backfilled 50 6" x 20'6"	4.28
25	2" diameter x 10' backfilled to 8" x 10'6" diameter	2.81

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TABLE 2			
Driving Potential			
P/S	Magnesium	Zinc	Aluminum ⁽¹⁾
-0.70	1.21	1.60	1.50
-0.80	1.07	1.20	1.17
-0.85	1.00	1.00	1.00
-0.90	0.93	0.80	0.83
-1.00	0.79	0.40	0.50
-1.10	0.64	0.00	0.17
-1.20	0.50	0.00	0.00

⁽¹⁾ Aluminum-Zinc-Indium alloy

TABLE 3					
No. of Anodes In Parallel	Adjusting Factors - Anode Spacing in Feet				
	5"	10'	15'	20'	25'
2	0.652	0.576	0.551	0.538	0.530
3	0.586	0.460	0.418	0.397	0.384
4	0.520	0.385	0.340	0.318	0.304
5	0.466	0.333	0.289	0.267	0.253
6	0.423	0.295	0.252	0.231	0.218
7	0.387	0.265	0.224	0.204	0.192
8	0.361	0.243	0.204	0.184	0.172
9	0.332	0.222	0.185	0.166	0.155
10	0.311	0.205	0.170	0.153	0.142
11	0.292	0.192	0.158	0.141	0.131
12	0.276	0.180	0.148	0.132	0.122
13	0.262	0.169	0.139	0.123	0.114
14	0.249	0.160	0.131	0.116	0.107
15	0.238	0.152	0.124	0.109	0.101
16	0.226	0.144	0.117	0.103	0.095
17	0.218	0.138	0.112	0.099	0.091
18	0.209	0.132	0.107	0.094	0.086
19	0.202	0.127	0.102	0.090	0.082
20	0.194	0.122	0.098	0.086	0.079
22	0.182	0.114	0.091	0.079	0.073
24	0.171	0.106	0.085	0.074	0.067
26	0.161	0.100	0.079	0.069	0.063
28	0.152	0.094	0.075	0.065	0.059
30	0.145	0.089	0.070	0.061	0.056

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TABLE 4 - Wire Table, Standard Annealed Copper

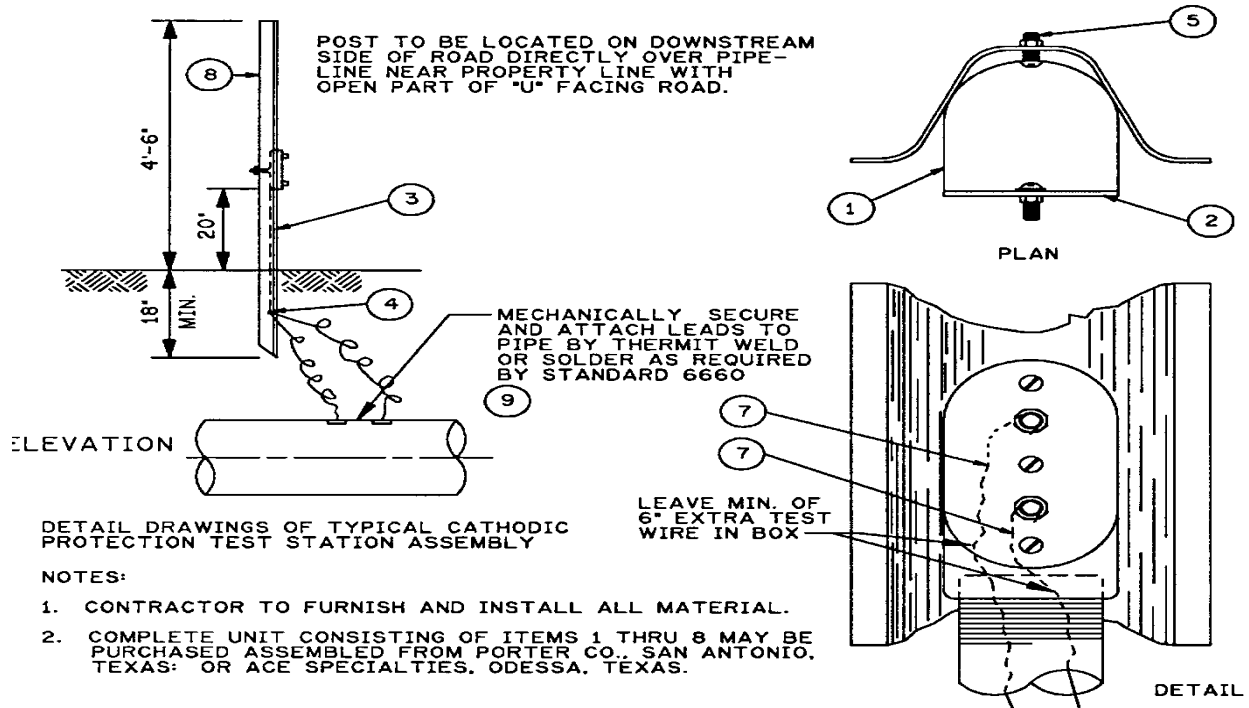
A.W.G. Gage No.	Diameter in Mils^(a)	Resistance in Ohms per 1000 ft^(a)	Weight in ^{(a)&(b)} pounds per 100 ft	Current Capacity (Amps)
0000	460.0	0.0490	640.5	370
000	409.6	0.0618	507.9	320
00	364.8	0.0779	402.8	270
0	324.9	0.0983	319.5	240
1	289.3	0.1239	253.3	200
2	257.6	0.1563	200.9	175
3	229.4	0.1970	159.3	155
4	204.3	0.2485	126.4	130
6	162.0	0.3951	79.5	95
8	128.5	0.6282	50.0	75
10	101.9	0.9989	31.4	50
12	80.8	1.5880	19.8	35
14	64.1	2.5250	12.4	30

(a) Values are for annealed copper at 20°C (68°F).
(b) Weight of copper only, weight of insulation not included.

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Appendix C:
CP Test Station
Design

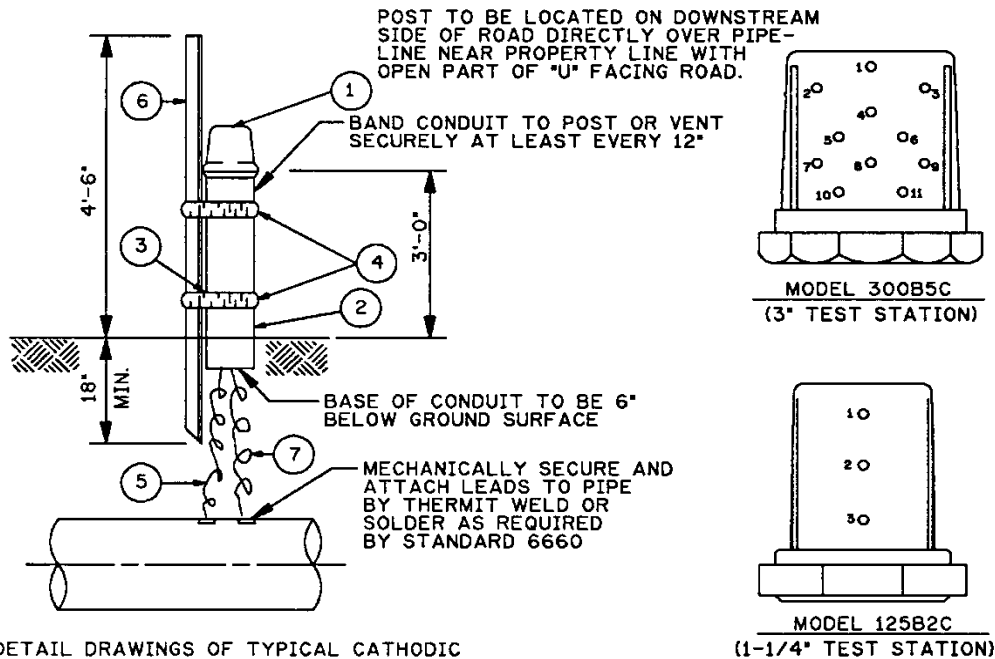
Type 1 CP test station



MATERIAL LIST				
MARK	REQ'D	SIZE	DESCRIPTION	UNIT
1	1	3/4"	CONDULET HEAD WITH 1/4" HOLE DRILLED IN CENTER OF BACK (FABRICATED AS PER PORTER CO., ACE, OR EQUAL)	340-
2	1	3/4"	BLANK CONDULET INSULATED COVER, WITH TWO 1/4" DRILLED HOLES	
3	1	3/4"X2'-6"	RIGID GALV. CONDUIT, REAMED AND THREADED BOTH ENDS	
4	1	3/4"	INSULATING BUSHUNG, THREADED	
5	1	3/16"X2"	MACHINE SCREW, CADMIMUM PLATED STEEL, W/2 NUTS AND FLAT WASHERS	
6	1	#10 X 3/4"	BRASS SCREW, 32NF, W/BRASS NUT AND TWO BRASS FLAT WASHERS	
7	1	AS REQ'D.	WIRE, NO. 10 OR 12 AWG, COPPER, 600V, THW INSULATION	
8	1	6'-0"	POST "U" TYPE STEEL POST (YELLOW)	
9	2	—	NO. 15 CHARGE, W/SLEEVE OR EUTEC ROD 157-1/8" AND EUTECTOR FLUX 157 OR EQUIVALENT	↓

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Appendix C: CP Test Station Design	Type 2 CP test station
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NOTES:

1. LITTLE FINK TEST STATION UNIT WILL BE INSTALLED AT ALL TEST STATIONS WHERE ONLY THREE (3) OR LESS WIRE CONNECTIONS ARE NEEDED. BIG FINK UNIT TO BE USED AT ALL OTHER LOCATIONS.
2. CONTRACTOR TO FURNISH AND INSTALL ALL MATERIAL.
3. COMPLETE UNIT CONSISTING OF ITEMS 1 THRU 5 MAY BE PURCHASED ASSEMBLED FROM: COTT MFG. CO., LOS ANGELES, CALF.

MATERIAL LIST				
MARK	REQ'D	SIZE	DESCRIPTION	UNIT
1	1	LITTLE FINK 1-1/4" OR BIG FINK 3"	FINK TEST STATION, COTT MANUFACTURING CO., YELLOW MODEL, COMPLETE WITH CIRCUIT BOARD DECAL. (OR EQUAL)	340- —
2	1	1-1/4" X 3' LG. OR 3" X 3' LG.	CONDUIT, YELLOW POLYETHYLENE	↓
3	2	—	SPACER, COTT MANUFACTURING (NO. APX0036) (OR EQUAL)	
4	2 EA.	3/4"	SS "BAND-IT" BANDING MATERIAL (NO. C-206) WITH SS BUCKLE (NO. C-256) (OR EQUAL)	
5	1	AS REQ'D.	WIRE NO. 10 OR 12 AWG. COPPER, THW INSULATION	
6	1	6'-0"	POST "U" TYPE STEEL (YELLOW)	
7	2	—	NO. 15 CHARGE, W/SLEEVE OR EUTEC ROD 157-1/8" AND EUTECTOR FLUX 157 OR EQUIVALENT	↓

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Current Density Design Information													
				Design Current Density (DCD) (Amps per Mile @	Design Current Density (DCD) (Amps per Mile @	Design Current Density (DCD) (Amps per Mile @	Design Current Density (DCD) (Amps per Mile @	Design Current Density (DCD) (Amps per Mile @	Design Current Density (DCD) (Amps per Mile @	Design Current Density (DCD) (Amps per Mile @	Design Current Density (DCD) (Amps per Mile @	Design Current Density (DCD) (Amps per Mile @	Design Current Density (DCD) (Amps per Mile @
	Pipe Dia	Ft ² /lin Ft	Ft ² /Mile	10% bare	20% bare	30% bare	40% bare	50% bare	60% bare	70% bare	80% bare	90% bare	100% bare
	2	0.622	3284	0.33	0.66	0.99	1.31	1.64	1.97	2.30	2.63	2.96	3.28
	4	1.178	6220	0.62	1.24	1.87	2.49	3.11	3.73	4.35	4.98	5.60	6.22
	6	1.734	9156	0.92	1.83	2.75	3.66	4.58	5.49	6.41	7.32	8.24	9.16
	8	2.258	11922	1.19	2.38	3.58	4.77	5.96	7.15	8.35	9.54	10.73	11.92
	10	2.814	14858	1.49	2.97	4.46	5.94	7.43	8.91	10.40	11.89	13.37	14.86
	12	3.338	17625	1.76	3.52	5.29	7.05	8.81	10.57	12.34	14.10	15.86	17.62
	14	3.665	19351	1.94	3.87	5.81	7.74	9.68	11.61	13.55	15.48	17.42	19.35
	16	4.189	22118	2.21	4.42	6.64	8.85	11.06	13.27	15.48	17.69	19.91	22.12
	18	4.712	24879	2.49	4.98	7.46	9.95	12.44	14.93	17.42	19.90	22.39	24.88
	20	5.236	27646	2.76	5.53	8.29	11.06	13.82	16.59	19.35	22.12	24.88	27.65
	22	5.76	30413	3.04	6.08	9.12	12.17	15.21	18.25	21.29	24.33	27.37	30.41
	24	6.283	33174	3.32	6.63	9.95	13.27	16.59	19.90	23.22	26.54	29.86	33.17
	26	6.807	35941	3.59	7.19	10.78	14.38	17.97	21.56	25.16	28.75	32.35	35.94
	30	7.854	41469	4.15	8.29	12.44	16.59	20.73	24.88	29.03	33.18	37.32	41.47
	36	9.425	49764	4.98	9.95	14.93	19.91	24.88	29.86	34.83	39.81	44.79	49.76
	42	10.996	58059	5.81	11.61	17.42	23.22	29.03	34.84	40.64	46.45	52.25	58.06
	48	12.566	66348	6.63	13.27	19.90	26.54	33.17	39.81	46.44	53.08	59.71	66.35
	54	14.137	74643	7.46	14.93	22.39	29.86	37.32	44.79	52.25	59.71	67.18	74.64
	60	15.708	82938	8.29	16.59	24.88	33.18	41.47	49.76	58.06	66.35	74.64	82.94

Code Reference :	Procedure No.: HLD.25
49 CFR: 195.563	Effective Date: 04/01/18
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Line 100	Pipe Dia	Surface Area Ft2 /lin Ft	Surface Area Ft2/Mil e	Design Current Density (DCD) Amps per Mile @ 10% bare	DCD @	DCD @	DCD @	DCD @	DCD @	DCD @	DCD @	DCD @	DCD @
					20% bare	30% bare	40% bare	50% bare	60% bare	70% bare	80% bare	90% bare	100% bare
	2	0.622	3284	0.99	1.97	2.96	3.94	4.93	5.91	6.90	7.88	8.87	9.85
	4	1.178	6220	1.87	3.73	5.60	7.46	9.33	11.20	13.06	14.93	16.79	18.66
	6	1.734	9156	2.75	5.49	8.24	10.99	13.73	16.48	19.23	21.97	24.72	27.47
	8	2.258	11922	3.58	7.15	10.73	14.31	17.88	21.46	25.04	28.61	32.19	35.77
	10	2.814	14858	4.46	8.91	13.37	17.83	22.29	26.74	31.20	35.66	40.12	44.57
	12	3.338	17625	5.29	10.57	15.86	21.15	26.44	31.72	37.01	42.30	47.59	52.87
	14	3.665	19351	5.81	11.61	17.42	23.22	29.03	34.83	40.64	46.44	52.25	58.05
	16	4.189	22118	6.64	13.27	19.91	26.54	33.18	39.81	46.45	53.08	59.72	66.35
	18	4.712	24879	7.46	14.93	22.39	29.86	37.32	44.78	52.25	59.71	67.17	74.64
	20	5.236	27646	8.29	16.59	24.88	33.18	41.47	49.76	58.06	66.35	74.64	82.94
	22	5.76	30413	9.12	18.25	27.37	36.50	45.62	54.74	63.87	72.99	82.11	91.24
	24	6.283	33174	9.95	19.90	29.86	39.81	49.76	59.71	69.67	79.62	89.57	99.52
	26	6.807	35941	10.78	21.56	32.35	43.13	53.91	64.69	75.48	86.26	97.04	107.82
	30	7.854	41469	12.44	24.88	37.32	49.76	62.20	74.64	87.09	99.53	111.97	124.41
	36	9.425	49764	14.93	29.86	44.79	59.72	74.65	89.58	104.50	119.43	134.36	149.29
	42	10.996	58059	17.42	34.84	52.25	69.67	87.09	104.51	121.92	139.34	156.76	174.18
	48	12.566	66348	19.90	39.81	59.71	79.62	99.52	119.43	139.33	159.24	179.14	199.05
	54	14.137	74643	22.39	44.79	67.18	89.57	111.97	134.36	156.75	179.14	201.54	223.93
	60	15.708	82938	24.88	49.76	74.64	99.53	124.41	149.29	174.17	199.05	223.93	248.81



Coating Resistance Measurement

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	Procedure No.: D.29	
	Effective Date: 04/01/18	Page 1 of 4

1.0 Procedure Description This Standard Operating Procedure (SOP) describes testing methods for obtaining coating resistance measurements on below ground, coated pipelines.

2.0 Scope Coating resistance is used to determine the current requirement, and in the design of cathodic protection (CP) systems. Pipe-to-soil potential measurements and IR drop measurements, in conjunction with cycled current sources, are used to calculate the resistance of the coating on a pipeline.

3.0 Applicability This SOP applies to coated buried steel pipelines where CP current sources can be interrupted.

4.0 Frequency As required: When needed to determine the current requirement, and when designing CP systems

5.0 Governance The following table describes the responsibility, accountability, and authority for this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Vice President

6.0 Terms and Definitions Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP A.01 Glossary and Acronyms*.

Terms	Definitions
Coating Resistance	The electrical resistance of a coating to the flow of current, unit of measurement is ohms for one square foot of coating. Typical values range from less than 1000 ohms to more than 1,000,000 ohms for one square foot
Copper/Copper Sulfate Reference Cell	A reference cell whose open circuit potential is constant under similar conditions of measurement and is used for measuring the relative potentials of other electrodes

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Terms	Definitions
Electrolyte	An ionic conductor
IR Drop	The voltage drop across the resistance, in accordance with Ohm's Law
Pipeline Current	The amount of current flowing through a segment of pipeline considering IR drop and resistance in accordance with Ohm's Law
Pipeline Potential Measurement	The potential difference between the structure of a buried or a submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte
Rectifier	A device that converts alternating current (AC) to direct current (DC)
Test Stations	A point where direct electrical contact can be made to the facility that is being surveyed. Test point options include test site wires, mainline valves, taps, and selected points.

**7.0
Coating
Resistance
Measurement**

Operations Personnel follows the procedure below for coating resistance measurement.

Step	Activity
1	USE this method to measure the average resistance of the coated pipeline to ground for a specific length between two test stations.

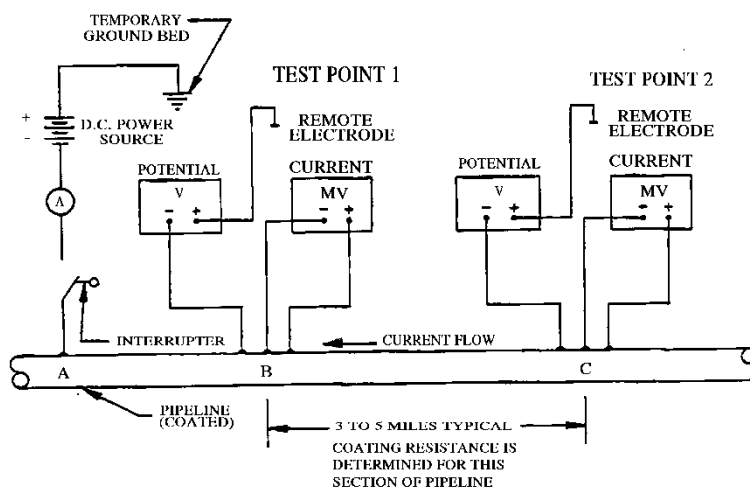


Figure 1: Resistance Diagram

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Step	Activity
2	OBTAIN pipeline potential measurement data to remote copper/copper sulfate reference cells, located at test stations at each end-of-the-line section, for coating resistance calculations.
3	TAKE potential readings with an applied DC current cycled “ON” and “OFF,” typically seven seconds ON and three seconds OFF.



NOTE: The current source may be a permanent rectifier, a test rectifier, or a battery source.

Step	Activity
4	MEASURE the pipeline current at the same test stations during the cycling process.
5	OBTAIN a change in pipe potential (ΔV) and a change in line current (ΔI) for each end of the pipe section.



NOTE: The difference in the two ΔI values is the current collected by the line section under test when the current is switched ON. The average of the two ΔV values is the average change in pipeline potential within the test section caused by the cycled test current. The average ΔV in millivolts divided by the current collected in milliamperes is the resistance to earth, in ohms, of the pipeline section tested.

Step	Activity
6	CALCULATE the total surface area (A) of the pipe section tested by using the length (L) and outside diameter (d) of the section where: $A = \pi d L$
7	MULTIPLY the pipe section to earth resistance by the area in square feet to obtain a value of ohms times square foot.
8	USE the following formulas and REFER to Figure 1: <ul style="list-style-type: none"> Average pipe-to-earth resistance between Test Point 1 and Test Point 2: $R_{c\ 1-2} = \frac{\Delta V_1 + \Delta V_2}{2 (\Delta I_1 - \Delta I_2)}$ Average coating resistance between Test Point 1 and Test Point 2: $R_{AVG} = R_{c\ 1-2} \times (\pi DL)$ <p>Where: πDL = Pipe Surface Area</p>

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<p>NOTE:</p> <ul style="list-style-type: none"> • This is the effective or average coating resistance for the section tested. • The two values of ΔI must differ significantly. A ratio of 2:1 is recommended to obtain sufficient precision in the calculations. • The two values of ΔV must not differ by much; otherwise, the arithmetic average is not a sufficiently close approximation to the average potential shift. The ratio of the two values of ΔV should not be greater than 1.6:1.
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Step	Activity
9	RECORD data on the applicable form(s) for <i>Cathodic Protection System Design</i> for use in CP design calculations.

**8.0
Documentation
Requirements**

Record data in the electronic database or utilize the following form(s) as applicable:

- D.16.A Cathodic Protection System Design

**9.0
References**

There are no documents referenced in this SOP.

**Appendix A:
OQ Task
Requirements**

There are no Operator Qualification (OQ) tasks required for this SOP.



**Internal Corrosion
Monitoring and Mitigation**

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	Procedure No.: HLD.30	
49 CFR: 195.579	<i>Effective Date:</i> 04/01/18	Page 1 of 17

1.0 Procedure Description This Standard Operating Procedure (SOP) describes internal corrosion monitoring and mitigation for the pipeline system.

2.0 Scope Monitoring the infrastructure of the pipeline system for indications of internal corrosion activity. Provide the data needed to initiate the appropriate corrective action in order to mitigate potentially corrosive conditions.

3.0 Applicability This SOP applies to jurisdictional pipeline facilities that are subject to internal corrosion.

4.0 Frequency The table below identifies the frequencies for internal corrosion monitoring and mitigation.

Task	Frequency
Review and update internal corrosion monitoring and treatment schedules.	Annually
Run cleaning pigs in pipeline segments in accordance with internal corrosion mitigation schedule.	As Required
Inspect and sample fluids and solids obtained from the pipeline system to include the following locations: <ul style="list-style-type: none"> • Water traps • Receivers 	As required

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Task	Frequency
Introduce biocides and/or corrosion inhibitors into the pipeline system as part of an Internal Corrosion Mitigation Plan.	As required
Review product quality violations to determine whether corrosive product has been introduced into the pipeline system.	As required

**5.0
Governance**

The following table describes the responsibility, accountability, and authority for this SOP.

Function	Responsibility	Accountability	Authority
Corrosive Product Determination	Corrosion Technician	Operations Manager	Director of Operations
Develop the Monitoring Schedule	Corrosion Technician	Operations Manager	Director of Operations
Implement the Monitoring Schedule	Corrosion Technician	Operations Manager	Director of Operations
Review and Update the Monitoring Schedule	Corrosion Technician	Operations Manager	Director of Operations
Develop the Treatment Schedule	Corrosion Technician	Operations Manager	Director of Operations
Implement Treatment Plan	Corrosion Technician	Operations Manager	Director of Operations
Review and Update the Treatment Schedule	Corrosion Technician Operations Personnel	Operations Manager	Director of Operations

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Function	Responsibility	Accountability	Authority
Reporting Requirements	Corrosion Technician	Operations Manager	Director of Operations

**6.0
Terms and
Definitions**

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	Definitions
Corrodants	Contaminants in liquid commodities that can create a corrosive environment or accelerate the corrosion process in pipeline infrastructure. Common contaminants include the following.

Water	Hydrogen Sulfide(1)	Carbon Dioxide(1)
Sulfur compounds(1)	Chlorides(2)	Oxygen(2)
Bacteria(1)	Solids or precipitates(3)	Corrosive liquids
(1)Requires the presence of water		
(2)Corrosion accelerant		
(3)Creates a concentration cell and can harbor bacteria		

Corrosive Product	Transported liquids that have the potential to initiate an electrochemical reaction within the pipeline system, resulting in metal loss.
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**7.0
Internal
Corrosion
Monitoring and
Mitigation**

The procedures that follow describe how to monitor and mitigate internal corrosion:

- Corrosive Product Determination
- Develop the Monitoring Schedule
- Implement the Monitoring Schedule
- Review and Update the Monitoring Schedule

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- Develop the Treatment Schedule
- Implement the Treatment Plan
- Review and Update the Treatment Schedule
- Reporting Requirements



NOTE: Consult with the Internal Corrosion Specialist and or Corrosion Specialist for the procedures listed above.

**7.1
Corrosive
Product
Determination**

To determine the amount and composition of corrosive liquids, Corrosion Technician uses the following steps.

Step	Activity
1	EVALUATE product quality tariff violation to determine whether corrosive product was introduced into the pipeline system.
2	EVALUATE water and solids collected to determine corrosivity of the liquids shipped
3	ANALYZE threshold values of the parameters in the sub procedures that follow for indications of corrosive product.

**7.2
Develop the
Monitoring
Schedule**

Corrosion Technicians and Operations Personnel develop an internal corrosion monitoring schedule for all pipelines and pipeline facilities in the area using applicable form(s).

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**7.2.1
Data Review**

Product quality data should be the foundation of each Pipeline Segment Internal Corrosion Monitoring Schedule. Verification that corrosive product is not transported in the pipeline segment ensures that a corrosive environment does not exist in the pipeline or associated tanks. If the product is determined to be corrosive, a mitigative program is developed if necessary based on the operational characteristics of the pipeline and the corrosivity of the product.

Operations Personnel, Measurement Technician, and Area Management follow these steps for the data review.

Step	Activity
1	REVIEW the product quality data with input from Corrosion Technician and Measurement Technician.
2	<p>REVIEW data from the following sources to verify that the Monitoring Schedule can provide adequate data to manage the threat of internal corrosion:</p> <ul style="list-style-type: none"> • Product quality • Product sample locations • Pipe inspection reports • Leaks • MFL inspections • Operations (pressure, flow, temperature) • Monitoring devices • NDE inspections • Hot tap coupons • Chemical treatment • Mechanical cleaning • Pipeline fluids and/or solids <ul style="list-style-type: none"> ○ Headers ○ Filter/separators ○ Receivers ○ Sample bottles ○ Tanks

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7.2.2 Management Review Operations Personnel Corrosion Technicians submits the Internal Corrosion Monitoring Schedule to Operations Manager for approval.

7.3 Implement the Monitoring Schedule To implement the internal corrosion monitoring schedule, Corrosion Technicians use the following sub procedures.

7.3.1 Product Quality Follow the steps below for product quality monitoring.

Step	Activity
1	INSTALL and MAINTAIN internal corrosion monitoring devices in the pipeline as outlined in the internal corrosion monitoring schedule.
2	VERIFY installation and maintenance of corrosion monitoring devices is in accordance with <i>SOP HLD.32 Weight Loss Coupons for Internal Corrosion Monitoring</i> and/or <i>SOP HLD.33 Internal Corrosion Monitoring Devices</i> .
3	

7.3.2 Liquid Samples Corrosion Technician tests free water samples obtained from the pipeline system for pH, chlorides and bacteria. Submit samples for additional laboratory analysis. Refer to *SOP HLD.07 pH Measurement*, *SOP HLD.38 Analysis of Solids and Liquids*, and *SOP HLD.39 Bacterial Corrosion Tests*. Consult with Corrosion Specialist for additional test parameters.

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**7.3.3
Solid, Sludge,
and Scale
Samples**

Test pipeline sludge/solids for free water, pH and bacteria. Submit pipeline scale, sludge, and solid samples for laboratory analysis, if necessary, to evaluate a specific concern such as an operational change.



NOTE: Laboratory analysis of solids, scales, sludge, and liquids removed from the pipeline should be considered to characterize the corrosive nature of said materials. Additional analysis of samples collected from the same location should be conducted whenever conditions within the pipeline are suspected to have changed. It is not necessary to analyze liquids removed from the pipeline that can be characterized by visual inspection (i.e. paraffin, hydrates, etc.)

**7.4
Review and
Update the
Monitoring
Schedule**

Operations Personnel review and update the internal corrosion monitoring schedule annually or when data indicates that pipeline conditions have changed.

**7.4.1
Sample
Analysis**

Follow the steps below when analyzing sample data results.

Step	Activity
1	<p>CONSIDER conducting a review of the internal corrosion monitoring schedule when analysis indicates a significant change in the following conditions inside the pipeline:</p> <ul style="list-style-type: none"> • pH • Bacteria population (SRB or APB) • A solid or sludge sample contains Iron Sulfide • A solid or sludge sample contains Iron Carbonate • A solid or sludge sample contains Ferric Hydroxide • Chlorides

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Step	Activity
2	CONSULT with the IC specialist and Corrosion Specialist to determine whether or not to update the internal corrosion monitoring schedule.

**7.4.2
ILI Data**

Operations Personnel and Corrosion Technician should consider a review of the internal corrosion program for a pipeline segment when Inline Inspection (ILI) data indicates the presence of internal corrosion anomalies. **CONSULT** with the Corrosion Specialist for internal corrosion preventative measures.

**7.4.3
Product
Quality
Monitoring**

When product quality monitoring indicates the introduction of corrosive product, consider conducting a review of the internal corrosion monitoring schedule.

**7.4.4
Measurement
Equipment**

The Measurement Technician notifies Operations Personnel if free water, solids, or indications of corrosion are observed in measurement equipment.



NOTE: Laboratory analysis of samples may be required to evaluate solids/liquids. Indications of corrosion must be evaluated by Operations Personnel.

**7.4.5
Pipeline
Notifications**

Notify Corrosion Technician and Operations Manager when:

- Product throughput and velocity in a line is reduced or increased or when a line is idled
- Free water, solids, or indications of corrosion are present in filter/separators, receivers, or headers,
- ILI??? Growth?
- An in-service failure, pipe replacement, coupon, or NDT inspection confirms the presence of internal corrosion

Upon notification, Corrosion Technician and Operations Manager follows these steps.

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Step	Activity
1	Upon notification, EVALUATE each condition to determine whether additional monitoring and treatment is required to address internal corrosion concerns.
2	Upon notification, PERFORM laboratory analysis of samples as required to evaluate solids and liquids. EVALUATE indications of corrosion.

7.4.6 Reporting

Operations Personnel uses the following steps for reporting requirements.

Step	Activity
1	RECORD all changes to the monitoring schedule using the applicable form(s) for <i>Internal Corrosion Monitoring Schedule</i> .



NOTE: Area Management approves all changes to the monitoring schedule.

Step	Activity
2	DOCUMENT the review of internal corrosion monitoring schedule using the applicable form(s) for <i>Annual Review-Internal Corrosion Monitoring and Treatment Schedules</i> .
3	
4	RECORD all free water, sludge, and solid inspection and analysis results in the Corrosion database. OBTAIN data from visual inspections, field testing, and laboratory analysis.
5	RECORD changes in operations of a pipe segment in the remarks column of the applicable form(s) for <i>Internal Corrosion Monitoring Schedule</i> . INCLUDE summaries on the impact of the changes with respect to internal corrosion, and DETAIL any changes in monitoring or treatment schedules.

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7.5 Develop the Treatment Schedule

Operations Personnel and Operations Manager develop an internal corrosion treatment schedule designed for each individual line segment based on site conditions. Internal corrosion treatment plans may require one-time, periodic, or continuous treatment.

Step	Activity
1	<p>DEVELOP an Internal Corrosion Treatment Schedule for each line segment where one of more of the following conditions exists:</p> <ul style="list-style-type: none"> • Consecutive corrosion rates exceed 1.0 mil per year on finished product and 3.0 mils per year on crude oil pipeline systems • Pitting or weight loss coupons is observed on consecutive cycles • Consecutive bacteria tests with 3 or more positive vials • In-service internal corrosion leak • Line transports corrosive product • Contains internal corrosion anomaly with RPR < 1.39 • Operates intermittently
2	<p>DOCUMENT the Treatment Schedule using the applicable form(s) for <i>Internal Corrosion Treatment Schedule</i>.</p>

7.5.1 On-stream Cleaning

For on-stream cleaning, follow these guidelines for treatment.

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Step	Activity
1	CONDUCT on-stream cleaning to remove potentially corrosive solids, liquids, and sludge from all pipeline segments included on the Treatment Schedule, as applicable.
2	DEVELOP a cleaning frequency based on the following parameters <ul style="list-style-type: none"> • Product quality data • Corrosion monitoring data (i.e. coupons) • Inhibitor residual data • Analysis of liquids and/or solids
	Before developing an alternate cleaning schedule, CONSULT the IC Specialist and/or Corrosion Specialist.
3	CONSULT with the IC Specialist and/or Corrosion Specialist to determine which type of pig(s) are best suited for a specific line segment.



NOTE:

- Pipeline segments must be piggable and have adequate product flow to propel the pig.
- A wide variety of cleaning pigs are available.
- Multiple runs using different types of pigs are often required to remove corrodants from the line.

**7.5.2
Biocides**

Operations Personnel may elect to use biocides for mitigation depending on conditions.

Step	Activity
1	CONSIDER using biocides to kill bacteria in the pipeline.

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2	DETERMINE the source of the biological growth in the pipeline. SAMPLE all inputs upstream of the sampling point where the biological growth was confirmed, if possible or practicle.
3	If (or as) necessary, SAMPLE individual producer facilities and equipment to determine the source of the biological contaminants.



NOTE:	
	<ul style="list-style-type: none"> • The use of biocides requires careful study to ensure the proper type and amount are used. • Most biocides are toxic, flammable, and corrosive in neat form (undiluted). • Consideration should be given to all other mitigation options before selecting biocides.

**7.5.3
Inhibitors**

Operations Personnel may elect to use inhibitors for mitigation depending on conditions.

Step	Activity
1	CONSIDER using corrosion inhibitors to retard the internal corrosion process or make the pipeline less susceptible to corrodants.



NOTE:	
	<ul style="list-style-type: none"> • The use of inhibitors requires careful study to ensure the proper type and amount are used. • Pipeline corrosion inhibition is generally a long-term mitigation strategy for pipelines that transport corrosive product. • Most corrosion inhibitors are toxic, flammable, and corrosive in neat form (undiluted). • Consideration should be given to all other mitigation options before selecting corrosion inhibition.

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Step	Activity
2	OBTAIN approvals for all new requests to use biocides and inhibitors prior to submitting the applicable form(s) for <i>Chemical Approval</i> to the Safety Administration.
3	For all new requests, OBTAIN approval from Corrosion Services Department.
4	
5	OBTAIN the list of company approved biocides and inhibitors from the MSDS database.

**7.5.4
Submit the
Treatment
Schedule**

Finalize, submit, and record the treatment schedule for each affected pipe segment as follows.

Step	Activity
1	<p>FINALIZE the Treatment Schedule for each pipe segment included on the schedule which may include the following:</p> <ul style="list-style-type: none"> • Pigging frequency and justification • Optimal pig velocity during pig run • Type of biocide or inhibitor • Injection rates • Equipment requirements • Manpower requirements • Duration of treatment program • Monitoring plan • Estimated cost • Chemical handling and storage considerations • Fluid and/or solids disposal plan
2	SUBMIT the internal corrosion treatment schedule to Area Management for approval and implementation.

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NOTE: Disposal of spent biocides or inhibitors will require a disposal plan. Contact the Environmental Specialist.

Step	Activity
3	RECORD approved <i>Internal Corrosion Treatment Schedule</i> using the applicable form(s).

**7.6
Implement the
Treatment Plan**

To implement the treatment plan, Operations Personnel uses these steps.

Step	Activity
1	INTRODUCE biocides, inhibitors, and/or cleaning pigs into the pipeline as far upstream of the source of contamination as possible.
2	OBTAIN and TEST liquid samples in accordance with the treatment schedule.
3	EVALUATE the effectiveness of the treatment schedule. MODIFY plan as required to mitigate threat of internal corrosion.
4	CONSIDER extended contact time to verify adequate treatment.
5	If possible, CLEAN lines prior to introduction of chemicals. SEE the note below.

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NOTE:

- Cleaning pigs are often run in conjunction with biocides or corrosion inhibitors.
- Approved chemical vendors can provide analytical services.
- Multiple treatments are often required to obtain desired results.
- Biocide and corrosion inhibitor treatment programs are much more effective if the line can be cleaned prior to introduction of the chemicals. This cleaning ensures contact of the chemicals to the biological colonies that can thrive under deposits of dirt and corrosion products and insures adequate chemical coverage along the walls of the pipe.

**7.7
Review and
Update the
Treatment
Schedule**

Operations Personnel and Corrosion Technician use these steps to perform a review and update of the Internal Treatment Schedule, a program which may include chemical treatment, line cleaning, and/or removal of contaminants. Area Management must approve all changes to the schedule.

Step	Activity
1	REVIEW and UPDATE the Internal Corrosion Treatment Schedule annually, or when data indicates that pipeline conditions have changed.
2	<p>EVALUATE the effectiveness of the internal corrosion treatment schedule considering these factors:</p> <ul style="list-style-type: none"> • Reduction or increase in corrosion rates measured by weight loss coupons or internal corrosion monitoring devices. • Maintenance of chemical residuals above or below target levels if target levels are defined. • Increase or reduction in bacteria counts. • Growth or no growth of indicated and validated internal corrosion features from multiple ILI surveys. • Prevention of leaks or ruptures on a system with a known history of such occurrences.
3	CONSIDER establishing target residual levels by laboratory testing of specific corrosion inhibitors and biocides.
4	USE data from the annual review to build a technical justification to maintain or deviate from target or current cleaning frequencies

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Step	Activity
5	If changes to the treatment schedule are necessary, SUBMIT changes to Area Management for approval.

**7.8
Reporting
Requirements**

Corrosion Technician perform these reporting requirements.

Step	Activity
1	RECORD all treatments in the Corrosion Database.
2	DOCUMENT annual review of internal corrosion treatment schedule using the applicable form(s).
3	RECORD all changes or updates to the internal corrosion treatment schedule using the applicable form(s).

**8.0
Documentation
Requirements**

Record data in electronic database or utilize the following form(s) as applicable:

- A.11.A Report of Pipeline Failures
- D.30.A Internal Corrosion Monitoring Schedule
- D.30.B Internal Corrosion Treatment Schedule
- D.30.C Annual Review – Internal Corrosion Monitoring and Treatment Schedules
- S-180B Chemical Approval

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- 9.0** BP D.07 pH Measurement
- References**
- HLD.32 Weight Loss Coupons for Internal Corrosion Monitoring
 - HLD.33 Internal Corrosion Monitoring Devices
 - HLD.38 Analysis of Solids and Liquids
 - HLD.39 Bacterial Corrosion Tests

Appendix A: The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

OQ Task Requirements

Function	OQ Task
Visual Inspection for Internal Corrosion	PLOQ414
Insert and Remove Coupons / Probes for Internal Corrosion Monitoring	PLOQ415
Demonstrate the use of inhibitors and biocides	PLOQ416
Collect sample for internal corrosion monitoring	PLOQ718



**Weight Loss Coupons for
Internal Corrosion
Monitoring**

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

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1.0 Procedure Description This Standard Operating Procedure (SOP) describes the selection and use of weight loss coupons as an internal corrosion monitoring device.

2.0 Scope The use of coupons in pipelines assists in providing insight into corrosion deposit composition, scale composition, type of corrosion attack, and effectiveness of corrosion inhibition programs. A coupon placed in a pipeline’s product stream for a specified period of time supplies “weight loss” data. This data provides a cumulative summary of conditions at a specific point on the pipeline during the exposure period. This SOP satisfies company requirements on properly placing, removing, and analyzing coupons.

3.0 Applicability This SOP applies to company pipelines as a part of the internal corrosion monitoring plan.

4.0 Frequency Twice each calendar year, with intervals not to exceed seven and one-half (7.5) months: Remove weight loss coupons from the pipeline system and evaluate.

5.0 Governance The following table describes the responsibility, accountability, and authority for this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	Definitions
Coupon	A sample of known weight constructed of metal similar to a pipeline used to evaluate the effects of corrosion in the pipeline.

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**7.0
Weight Loss
Coupons for
Internal
Corrosion
Monitoring**

Weight loss coupons are one of many internal corrosion monitoring devices used in an Internal Corrosion Monitoring Plan in accordance with *SOP HLD.30 Internal Corrosion Monitoring and Mitigation*.

Operations Personnel follows these procedures for weight loss coupons:

- Selection of weight loss coupons
- Placement of weight loss coupons
- Installation and removal of weight loss coupons
- Analysis of weight loss coupons
- Reporting requirements

**7.1
Selection of
Weight Loss
Coupons**

Several types of weight loss coupons are available from a variety of vendors. Some may not be compatible with existing hardware. For selection of coupons, follow the procedure below.

Step	Activity
1	REVIEW system configuration and operational requirements. DETERMINE which type of weight loss coupon is most appropriate for the application.
2	SELECT strip coupons for most pipeline applications. First, CONSIDER strip coupons for every weight loss application. CONSIDER a rod or a disc coupon if a technical justification exists, such as high velocity applications like offshore applications.



NOTE:
<ul style="list-style-type: none"> • Strip coupons may be subject to “edge attack” corrosion in high velocity lines. • Flush mounted disc coupons do not have to be removed during pigging operations.

Step	Activity
3	SELECT disc coupons when: <ul style="list-style-type: none"> • The coupon is exposed to high product velocity. • Space requirements prohibit use of strip coupons. • Flush mount coupons are required.
4	SELECT rod coupons when the coupon is exposed to high product velocity or when multiple coupons are required at the same location to obtain data during various exposure periods.
5	CONSIDER dual strip coupon installations in areas where internal corrosion rates have not been established or where questionable data has been obtained. REFER to Figure 1 in <i>Appendix B</i> .

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NOTE: Weight loss data from dual coupons are usually averaged to provide a single weight loss reading. Dual data sources can help identify erroneous data due to improper coupon handling or manufacture.

7.2 Placement of Weight Loss Coupons

Coupon placement reflects the worst case potential for internal corrosion. Elevation profiles, flow modeling, leak history, and ILI data assist in site selection. Coupon locations must have adequate space to allow for installation of extraction equipment, as required, and for removal of coupon staff. Coupon placement within devices (water Traps) installed at locations to simulate conditions of worst case for internal corrosion are also used.

To accomplish placement of weight loss coupons, use the steps below.

Step	Activity
1	PLAN to install weight loss coupons at locations where internal corrosion is most likely to occur. CONSIDER areas where fluids are known or suspected to accumulate.



WARNING: Insertion and extraction of weight loss coupons at line pressure requires specialized equipment and training. Serious injury and/or death may result if manufacturer guidelines for coupon insertion and extraction are not followed exactly. Equipment and procedures for coupon insertion and extraction at line pressure must be approved by the Corrosion Specialist/Supervisor

Step	Activity
2	DETERMINE whether the coupon must be installed and retracted at line pressure. MAKE every effort to install coupons in areas that do not require insertion and extraction at line pressure. CONSIDER installation of water traps.
3	DETERMINE where the coupon(s) should be placed within the product stream to obtain representative data.



NOTE:

- The most common placement for weight loss coupons in pipelines is near the bottom of the line where fluids accumulate. Water traps simulate this condition.
- Data received from weight loss coupons reflects conditions within the pipeline or vessel at the point of coupon exposure. Proper coupon placement is required to obtain meaningful data.

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- Most coupons must be removed from the pipeline prior to line cleaning and in-line inspections.

**7.3
Installation and
Removal of
Weight Loss
Coupons**

Installation and removal of weight loss coupons is accomplished by the following steps.

Step	Activity
1	<p>VERIFY that coupons received from supplier meet the following criteria:</p> <ul style="list-style-type: none"> • Etched or stamped with unique ID number • Constructed of mild steel (low carbon – 0.1 to 0.2%) • Glass bead finish (typical) • Weighed to 0.1 milligrams • Packaged in a moisture-proof envelope <p>VERIFY the supplier provides data sheets including dimensions, material composition, serial number, and weight in grams with each coupon.</p>
2	<p>CONSIDER fabricating coupons from scrap pipe for installation in pipelines constructed of vintage steels.</p>



NOTE: Additional surface preparation is required for advanced coupon analysis such as Scanning Electron Microscopy, Energy Dispersive X-Ray Analysis, and Epifluorescent Microscopy.

Step	Activity
3	<p>WEAR clean, lint-free cotton gloves or disposable latex gloves when handling coupons. DO NOT TOUCH coupons with bare hands. DO NOT SCRAPE, RINSE OFF, HANDLE with tools, or ALTER coupons in any fashion.</p>
4	<p>MINIMIZE exposure time of the coupon to the atmosphere. REMOVE new coupons from corrosion resistant packaging prior to installation.</p>
5	<p>DO NOT COAT the coupon with grease. DO NOT REMOVE or ALTER any deposits, as polished metal surfaces can flash rust when exposed to the atmosphere.</p>
6	<p>INSULATE coupons from holders to prevent formation of a corrosion cell between the coupon and holder.</p>



NOTE: Coupon holders are generally constructed of stainless steel. Dielectric spacers, nuts, and bolts can be obtained from the coupon vendor.

Weight Loss Coupons for Internal Corrosion Monitoring

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Step	Activity
7	IDENTIFY the location of the leading edge of strip coupons on the top of the coupon staff to allow for proper orientation once the coupon is installed.
8	INSTALL strip coupons with the narrow edge in the axial direction (facing product flow). POSITION coupons so that serial numbers (most commonly stamped on one narrow edge) are downstream of the product flow.
9	INSTALL strip coupons with narrow edge in the up position to prevent solids accumulation on the widest surface of the coupon in water trap installations.
10	If using a strip coupon, ALIGN the narrow edge of the coupon to face the product flow.
11	Upon removal, CLEAN coupon by wiping down and VISUALLY inspect the coupon noting pitting and solids accumulations
12	
13	PLACE extracted coupons in corrosion resistant packaging provided by the coupon vendor immediately upon extraction and send to lab for analysis.



NOTE: Most coupons must be removed from the pipeline prior to line cleaning and in-line inspections.

7.4 Analysis of Weight Loss Coupons

Weight loss coupons are general indicators of internal corrosion activity, but do not provide definitive answers about the internal corrosion rates within pipeline facilities. Integrate coupon data with product quality data, operational data, MIC data, chemical inhibition data, MFL data, and pigging data to determine whether coupon placement and duration of exposure indicate pipeline conditions.

Use the following procedure to analyze weight loss coupons.

Step	Activity
1	SUBMIT coupons in corrosion resistant packaging to vendor for analysis as applicable. FOLLOW vendor requirements for packaging and shipping coupons. PROVIDE vendor with installation and extraction dates.
2	REVIEW weight loss, scale analysis, and visual inspection data obtained from coupon analysis.
3	<p>CALCULATE corrosion rate of the weight loss coupon using the following formula.</p> $CR = \frac{(IW - FW) \times 2280}{A \times T}$ <p>Where: CR = Corrosion Rate (Mils Per Year) IW = Initial Coupon Weight (Grams)</p>

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Step	Activity
	FW = Final Coupon Weight (Grams) A = Area of Coupon (Square Inches) T = Exposure Period (Days)
4	Pitting MPY = (Mils Per Year of Pitting) CALCULATE Pitting MPY when applicable using the following formula: Pitting rate (MPY) = $\frac{\text{Depth of deepest pit (mil)} \times 365}{\text{Exposure time (days)}}$



NOTE: The formulas are only valid for carbon steel coupons. Contact The Corrosion Department to determine corrosion rates in non-carbon steel coupons.

**7.5
Reporting
Requirements**

Record the following in the Corrosion Database :

- Coupon ID number
- Coupon type
- Installation Date
- Removal date
- Exposure period
- Initial weight
- Final weight
- Corrosion rate
- Pitting Corrosion Rate, if applicable
- Comments concerning the appearance of the coupon
- Complete reporting requirements in applicable electronic database.

**8.0
Documentation
Requirements**

Record data in electronic database or utilize the following form(s) as applicable:
Corrosion database

**9.0
References**

HLD.30 Internal Corrosion Monitoring and Mitigation

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Appendix A: The table below identifies the Operator Qualification (OQ) task requirements for this SOP.
OQ Task Requirements

Function	OQ Task
Insert and remove coupons/probes for Internal Corrosion Monitoring	PLOQ415

Appendix B: The following figures illustrate various coupon-related situations.
Figures

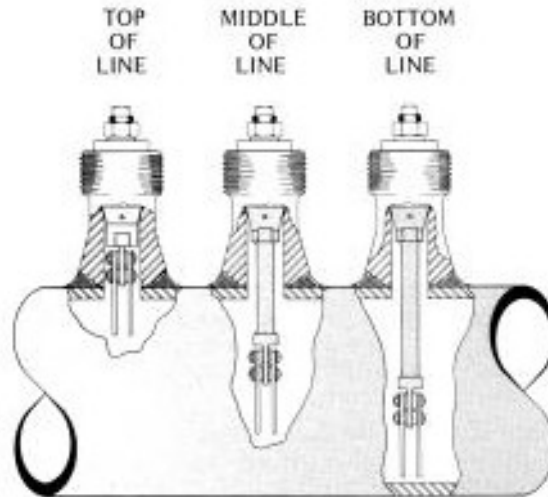


Figure 1 - Examples of Typical Dual Strip Coupon Installations
Note that Coupons Shown Rotated 90° from Normal Position

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Figure 3 – Multiple Rod Coupon Assembly

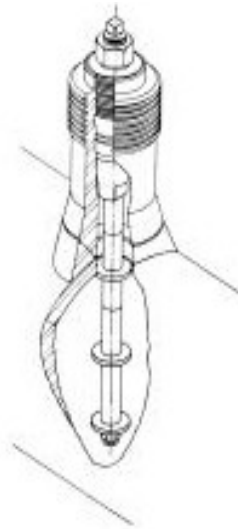


Figure 4 – Multiple Disc Coupon Assembly



Standard Operating Procedures

Internal Corrosion Monitoring Devices

Applicable to Hazardous Liquids Pipelines and Related Facilities

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1.0
Procedure Description

This Standard Operating Procedure (SOP) describes a variety of intrusive and non-intrusive devices available to monitor internal corrosion in the pipeline system. Weight loss coupons are the most common and are not included in this SOP. Reference *SOP HLD.32 Weight Loss Coupons for Internal Corrosion Monitoring*.

2.0
Scope

Indirect Corrosion Monitoring Devices are used when weight loss coupons cannot be used or these devices are more suited for the application. Conditions where these devices may be used are when:

- It is difficult or impractical to insert a weight loss coupon
- A general trend of the corrosion rate is sufficient
- Shorter evaluation periods are necessary to define a corrosion event or upset condition

Every effort should be made to install probes in areas that do not require insertion and extraction at line pressure. Installation in areas where typical product flow occurs but is not pigged should be considered.

3.0
Applicability

This SOP applies to company pipelines as part of the internal corrosion-monitoring program.

4.0
Frequency

For corrosive product monitor 2 times each calendar year with intervals not to exceed 7 and one-half months

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5.0 The following table describes the responsibility, accountability, and authority for this SOP.

Governance

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms and Definitions

Terms	Definitions
Hydrogen Patches	Captures the hydrogen gas pressure that is accumulated when corrosion occurs and travels through the pipe wall.
ER Probes	Designed to measure uniform corrosion rates in steady product flow.
LPR Probes	Provides corrosion rates in areas where liquids accumulate
UT Probes	Measures the thickness of the pipe wall in a constant location.
Intrusive probes	Require installation inside the pipeline
Non-intrusive probes	Do not require tapping into or placing inside the pipeline

7.0 The following procedures are found in this section:

Internal Corrosion

- Selection of Internal Corrosion Monitoring Devices
- Placement of Probes
- Installation of Probes

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**Monitoring
Devices**

- Data From Probes
- Analysis of Probe Data



NOTE: Consult with the Internal Corrosion Specialist and or Corrosion Specialist for the procedures listed above.

**7.1
Selection of
Internal
Corrosion
Monitoring
Devices**

Operations Personnel selects internal corrosion monitoring devices, depending on pipeline system conditions. The Operations Manager must approve all internal corrosion monitoring devices and the Internal Corrosion Specialist or Corrosion Specialist can assist with probe selection.

Step	Activity
1	CONSIDER weight loss coupons for corrosion monitoring applications.
2	CONSIDER the instrumentation best suited to obtain required data to define the condition being tested. ER, LPR, and UT probes have defined purposes and the correct probe should be selected for this purpose.
3	REVIEW the system configuration and operational requirements of the pipeline.
4	<p>SELECT the probe, based on pipeline system conditions. CONSIDER the following factors:</p> <ul style="list-style-type: none"> • Metallurgy of sensing element(s) • Anticipated corrosion rate • Resistivity of electrolyte within pipeline • Sensitivity of required data • Retractable or fixed mount • Mechanical protection for element(s) • Pressure/temperature range • Flush mount/standard mount

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Step	Activity
5	<p>CONSIDER UT probes where the following conditions exist:</p> <ul style="list-style-type: none"> • Areas where corrosive liquids are known to accumulate • Multiple probes are needed to provide a more comprehensive analysis of metal loss • Where intrusive probes are not desirable, due to pipeline operations
6	<p>DO NOT CONSIDER UT probes where the external temperature of the pipe exceeds 200°F.</p>



NOTE:

- Lead length for UT probes must be specified at the time of the order.
- UT probes must be equipped with a temperature sensor to compensate for sound wave speed variations due to temperature changes.

Step	Activity
7	<p>CONSIDER ER probes where the following conditions exist:</p> <ul style="list-style-type: none"> • Known areas where corrosive liquids exist • The area is accessible or equipped with test leads that terminate in an accessible area in order to obtain readings • Where fluid flow is not less than one foot per second (0.68 miles per hour) • Where time lapse corrosion rates are required
8	<p>DO NOT USE ER probes:</p> <ul style="list-style-type: none"> • Where localized corrosion (pitting) is probable • In stagnant areas, as readings are often inaccurate • In piggable line segments, unless the probe is retractable and approved by the area management
9	<p>CONSIDER LPR probes where the following conditions exist:</p> <ul style="list-style-type: none"> • Known areas where corrosive liquids exist

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Step	Activity
	<ul style="list-style-type: none"> • The area is accessible or equipped with test leads that terminate in an accessible area in order to obtain readings • Real time corrosion rates are required
10	DO NOT USE LPR probes in piggable line segments unless the probe is retractable and approved by the area management.
11	Consider installing LPR and ER probes jointly to obtain real time (LPR) and time-lapse (ER) corrosion rates. The IC Specialist and Corrosion Specialist can assist with probe selection.



NOTE: Clean, bare electrodes will normally corrode at a faster rate than aged pipeline steel until corrosion products or inhibitors deposit on the new metal surfaces and reach a state of corrosion/polarization equilibrium. Thus, corrosion rates obtained from recently installed ER and LPR probes will not immediately represent pipeline corrosion rates.

Step	Activity
12	CONSIDER hydrogen probes where aggressive internal corrosion or hydrogen generation is known to occur.
13	DO NOT USE hydrogen probes in piggable line segments unless approved by Division and Corporate Technical Staff.



NOTE:

- The presence of hydrogen sulfide in the gas stream will increase the diffusion of atomic hydrogen into the steel lattice.
- Hydrogen probes must be equipped with a temperature sensor to compensate for expansion/contraction of gas due to temperature changes.

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7.1.1 Operations Personnel follows the procedure below for ER probes.
ER Probes

Step	Activity
1	CONSIDER ER probes in areas where corrosive liquids are known to accumulate and weight loss coupons are not feasible or weight loss coupons do not fit the intended purpose.
2	SELECT ER probe based on pipeline system conditions. CONSIDER the following factors: <ul style="list-style-type: none"> • Metallurgy of sensing element(s) • Anticipated corrosion rate • Resistivity of electrolyte within pipeline • Sensitivity of required data • Retractable or fixed mount • Mechanical protection for element(s) • Pressure / temperature range • Flush mount / standard mount



NOTE: Corrosion Specialist can assist with probe selection.

- ER probes utilize a sacrificial element and have a specified (estimated) life.
- A specialized instrument is required to obtain readings from ER Probes. Probes must either be installed in an accessible area or equipped with test leads that terminate in an accessible area.
- ER probes are designed to measure uniform corrosion rates. ER probes should not be used in applications where localized corrosion (pitting) is probable.
- ER probes should be located in areas where fluid flow is not less than 1 foot per second (0.68 miles per hour). Probes located in stagnant areas will often provide inaccurate data.
- ER probes should not be installed in any piggable line segment unless they are the retractable type and without approval of Area Management. (Probes protruding into the line could be damaged by pigs).
- Corrosion rates obtained from recently installed ER probes will not immediately represent pipeline corrosion rates. Clean bare electrodes / sacrificial elements will normally corrode at a faster rate than aged pipeline steel until corrosion

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products or inhibitors deposit on the new metal surfaces and reach a state of corrosion equilibrium.

Step	Activity
3	INSTALL ER probes with electrode(s) in areas where corrosive liquids are known to accumulate.



NOTE: Probes can provide inaccurate readings if one electrode shields the other from the liquid stream.

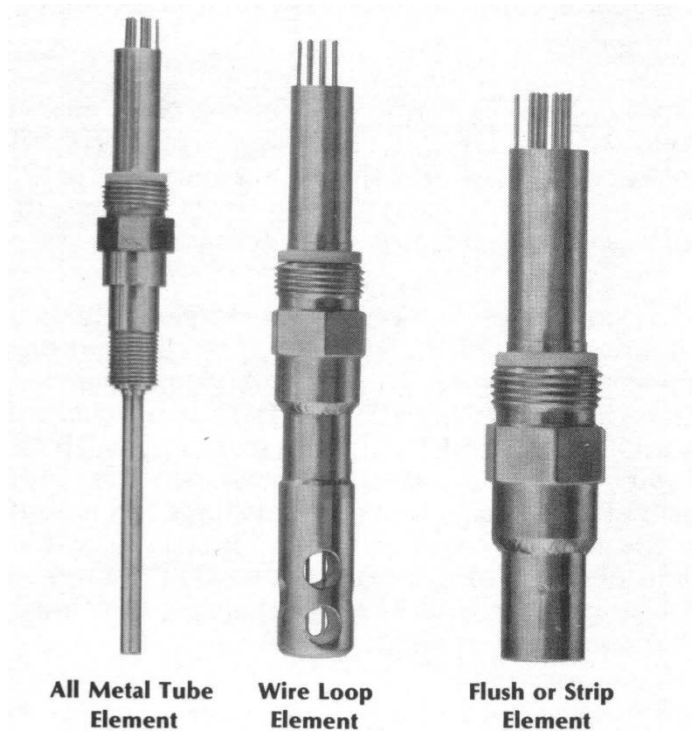


Figure 1: Typical ER Probes

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**7.1.2
LPR Probes**

The area Operations Personnel follows the procedure below for LPR probes.

Step	Activity
1	CONSIDER LPR probes in areas where corrosive liquids are known to accumulate and real time corrosion rates are required and weight loss coupons are not feasible.



NOTE: LPR probes are often installed in tandem with ER probes to provide real time (LPR) and time lapse (ER) corrosion rates.

Step	Activity
2	<p>SELECT type of probe based on pipeline system conditions. CONSIDER the following factors:</p> <ul style="list-style-type: none"> • Metallurgy of sensing element(s) • Anticipated corrosion rate • Resistivity of electrolyte within pipeline • Sensitivity of required data • Retractable or fixed mount • Mechanical protection for element(s) • Pressure / temperature range • Flush mount / standard mount



NOTE:

- IC Specialist and Corrosion Specialist can assist with probe selection.
- LRP probe electrodes will corrode and have a specified (estimated) life based on estimated corrosion rates.

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- A specialized instrument is required to obtain readings from LPR Probes. Probes must either be installed in an accessible area or equipped with test leads that terminate in an accessible area.
- LPR probes should not be installed in any piggable line segment unless they are the retractable type and without approval from Area Management. (LPR Probes protruding into the line could be damaged by pigs).
- LPR probes are designed to measure uniform corrosion rates. LPR probes should not be used in applications where localized corrosion (pitting) is probable.
- Corrosion rates obtained from recently installed LPR probes will not immediately represent pipeline corrosion rates. Clean bare electrodes will normally corrode at a faster rate than aged pipeline steel until corrosion products or inhibitors deposit on the new metal surfaces and reach a state of corrosion / polarization equilibrium.

Step	Activity
3	INSTALL LPR probes with electrode(s) in areas where corrosive liquids are known to accumulate. ORIENT probe such that all electrodes are perpendicular to product flow.



NOTE: Probes can provide inaccurate readings if one electrode shields the other from the product stream.

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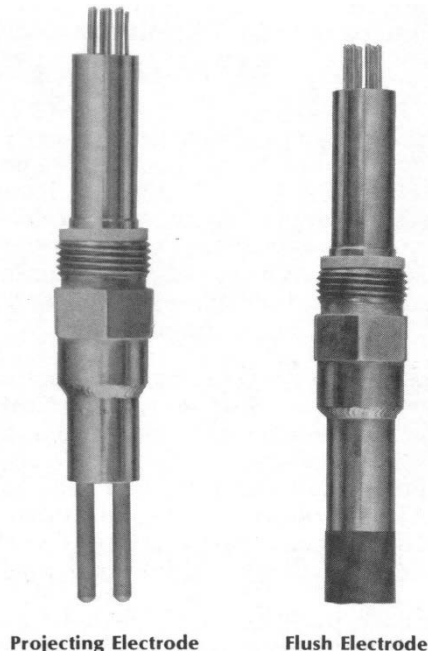


Figure 2: Typical LPR Probes

**7.1.3
UT Probes**

Consider UT probes in areas where corrosive liquids are known to accumulate.

UT probes are relatively inexpensive and non-intrusive. Probes attach to the pipe wall using a quick set epoxy. Only applicable when approved by the IC Specialist and Corrosion Specialist.



NOTE:

- A specialized instrument is required to obtain readings from UT Probes. Lead length for probes must be specified at time of order.
- Multiple UT probes can be installed in an area of concern to provide a more comprehensive analysis of metal loss.
- UT probes must be equipped with a temperature sensor to compensate for sound wave speed variations due to temperature changes.

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Figure 3: UT Probe Installation on the Ontario Drip

7.1.4 Hydrogen Probes

Consider Hydrogen probes in areas where aggressive internal corrosion or hydrogen generation is known to occur.

IC Specialist and Corrosion Specialist can assist with probe selection.



NOTE:

- Most pipeline internal corrosion features will not produce levels of atomic hydrogen that can be detected using hydrogen probes.
- The presence of hydrogen sulfide in the product stream will increase the diffusion of atomic hydrogen into the steel lattice.
- Hydrogen probes must be equipped with a temperature sensor to compensate for temperature changes.
- Intrusive hydrogen probes shall not be installed in any piggable line segment without approval from Area Management

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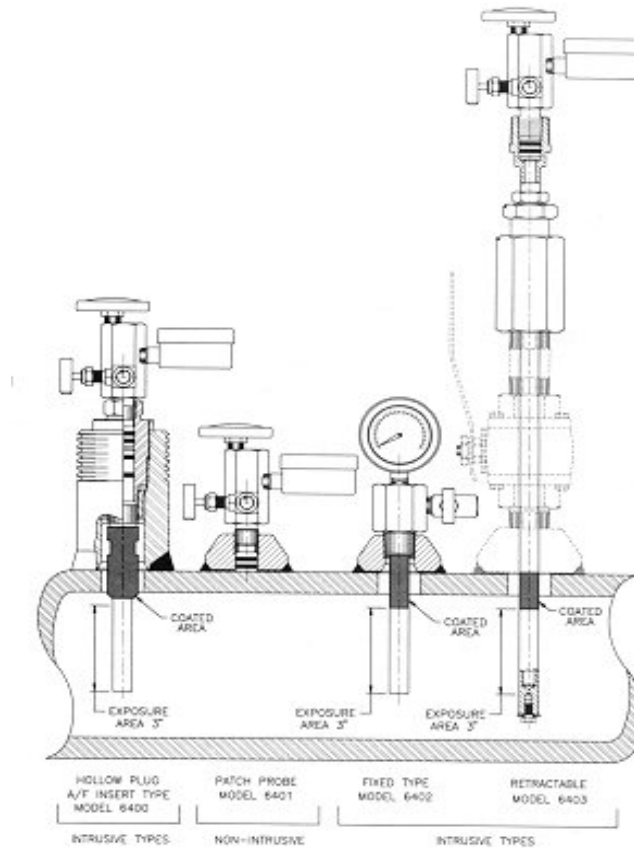


Figure 4: Types of Hydrogen Probes

**7.2
Placement of
Probes**

Operations Personnel follows the procedure below for placement of probes.

Step	Activity
1	INSTALL probes at locations where internal corrosion is most likely to occur (i.e., locations where fluids are known or suspected to accumulate). REFER to elevation profiles, flow modeling, leak history, and ILI data for assistance in site selection.

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<p>NOTE:</p> <ul style="list-style-type: none"> • Probe placement should reflect the worst-case potential for internal corrosion. Elevation profiles, flow modeling, leak history, and ILI data can assist in site selection. Probe locations must have adequate space to allow for installation of extraction equipment, as required, and connection of monitoring equipment. • Data received from internal corrosion monitoring probes reflects conditions within the pipeline or vessel at the point of exposure. Proper placement is required to obtain meaningful data. • Most intrusive probes must be removed from the pipeline prior to line cleaning and in-line inspections.
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Step	Activity
2	DETERMINE whether the probe must be installed and retracted at line pressure.
3	DETERMINE where the probe(s) should be placed within the product stream to obtain representative data.
4	REVIEW site selection with IC Specialist and Corrosion Specialist.
5	VERIFY that the probe locations have adequate space to allow for installation of extraction equipment and/or connection of monitoring equipment.
6	Where possible, INSTALL probes in areas that do not require insertion and extraction at line pressure.
7	If the probe must be installed and retracted at line pressure, CONSIDER installing on pipe that normally sees flow but can be isolated and depressurized for installation and extraction.
8	REMOVE intrusive probes from the pipeline prior to line cleaning and in-line inspections, if necessary to prevent damaging the probe.



<p>NOTE: The most common placements for probes in crude oil pipelines are near the bottom of the line where water accumulates and at devices that simulate water</p>

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hold up locations. In finished product pipelines the probes are typically installed in the product stream as water drop out is not a common issue.



WARNING: Insertion and extraction of probes at line pressure requires specialized equipment and training. Serious injury and / or death may result if manufacturer’s guidelines for coupon insertion/extraction are not followed exactly. Equipment and procedures for probe insertion and extraction at line pressure must be approved by the Corrosion Specialist/Supervisor

**7.3
Installation of
Probes**

Operations Personnel follows the procedure below for probe installation.

Step	Activity
1	<p>VERIFY that probes received from supplier meet the following criteria:</p> <ul style="list-style-type: none"> • Etched or stamped with unique ID number • Constructed of mild steel (low carbon – 0.1 to 0.2%) • Electrodes packaged in a moisture-proof envelope



NOTE: Data sheets to include dimensions, electrode composition (as applicable), serial number, and calibration certificates (as applicable) should be supplied with each probe. The manufacturer supplies data sheets that include dimensions, electrode composition (as applicable), serial number, and calibration certificates (as applicable) with each probe.

Step	Activity
2	<p>WEAR clean, lint free cotton gloves or disposable latex gloves when handling ER or LPR probes.</p>

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NOTE: The electrodes/sacrificial elements of ER and LPR probes shall not be touched with bare hands, scraped, rinsed off, handled with tools, or altered in any fashion.

Step	Activity
3	MINIMIZE exposure time to the atmosphere. REMOVE new ER and LPR probes from corrosion resistant packaging immediately prior to installation.



NOTE: Polished metal electrodes/sacrificial elements can flash rust when exposed to the atmosphere. Do not coat probe electrodes/sacrificial elements with grease, oil, or corrosion inhibitor.

Step	Activity
4	DO NOT COAT probe electrodes/sacrificial elements with grease, oil, or corrosion inhibitor.
5	INSTALL intrusive or non-intrusive probes in crude oil pipelines on the bottom of the pipeline where water accumulates and at devices that simulate water hold up locations. In finished product pipelines the probes are typically installed on the top of the pipe in the product stream. CONSULT the IC Specialist and Corrosion Specialist for installation guidance.

7.4

Operations Personnel follows the procedure below for obtaining data from probes.

Data from Probes

Step	Activity
1	CONNECT appropriate instrument to ER, LPR, or UT probe in accordance with manufacturer’s instructions.

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NOTE: Hydrogen probes utilize a direct read pressure gauge.

Step	Activity
2	ADJUST instrument to select appropriate probe type and meter sensitivity in accordance with manufacturer’s instruction.



NOTE: Instrument adjustments vary based on units. Follow manufacturer’s instructions to ensure calibration of the instrument prior to use.

Step	Activity
3	RECORD pressure, temperature, wall thickness, resistance, current, and/or corrosion rate, as applicable.



NOTE:

- Parameters are probe specific.
- Many electronic instruments can calculate corrosion rates and store probe data. All user inputs must be verified to ensure that calculations are correct.

**7.5
Analysis of
Probe Data**

Operations Personnel follows the procedure below for analyzing probe data.



NOTE: Data obtained from internal corrosion monitoring probes is a general indicator of internal corrosion activity and may not provide definitive answers about the internal corrosion rates within pipeline facilities. Probe must be integrated with product quality data, operational data, MIC data, chemical inhibition data, MFL

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data, weight loss coupon data, and pigging data to determine whether probe placement and duration of exposure are indicative of pipeline conditions.

Step	Activity
1	CALCULATE corrosion rate; pressure differential; and/or wall thickness differential based on data obtained from the internal corrosion monitoring probes.
2	REVIEW current and historic corrosion rate; pressure differential; and/or wall thickness differential.
3	<p>VERIFY that probe data is integrated with the following if applicable:</p> <ul style="list-style-type: none"> • Product quality data • Operational data • MIC data • Chemical inhibition data • MFL data • Weight loss coupon data • Pigging data <p>USE this information to determine whether probe placement and duration of exposure are indicative of pipeline conditions.</p>
4	EVALUATE probe data per <i>SOP HLD.30 Internal Corrosion Monitoring and Mitigation</i> .



NOTE: Data obtained from internal corrosion monitoring probes is a general indicator of internal corrosion activity and may not provide definitive answers about the internal corrosion rates within pipeline facilities.

Step	Activity
5	RECORD probe type, ID number, installation date, and all field data obtained from each probe in the Corrosion Database.
6	COMPLETE reporting requirements in applicable electronic database

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8.0 Record data in electronic database or utilize the following form(s) as applicable:

Documentation Requirements

- Corrosion Database
- EAM- Acknowledge the requirements as outlined in the SOP have been completed. Record exceptions in the description tab.

9.0 HLD.32 Weight Loss Coupons for Internal Monitoring Devices

References

Appendix A: The table below identifies any Operator Qualification (OQ) task requirements for this SOP.

OQ Task Requirements

Task Description	OQ Task
Insert and Remove Coupons / Probes for Internal Corrosion Monitoring	PLOQ415



Buried Pipe Inspections

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

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1.0 Procedure Description

This Standard Operating Procedure (SOP) describes the inspection of buried pipe and coatings whenever any portion of a buried pipeline is exposed or found to be exposed.

2.0 Scope

Federal regulations require an ongoing program of buried pipeline inspections to monitor coating and pipe condition.

3.0 Applicability

This SOP applies to company facilities with buried pipeline segments.

4.0 Frequency

As required: Whenever buried pipeline is exposed or found to be exposed.

5.0 Governance

The following table describes the responsibility, accountability, and authority for this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	Definitions
Underground pipe	Any pipeline that is buried underground, or is designed to be underground but has become exposed.

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**7.0
Buried Pipe
Inspections**

Operations Personnel uses the procedures that follow to inspect buried pipeline segments:

- Data collection
- Excavation
- External corrosion defects
- Internal defects
- Evaluation of mechanical defects



CAUTION: Structure-to-electrolyte potentials should be taken on all underwater facility inspections each time a facility is exposed or inspected by a diver or remote monitoring vehicle, (i.e., subsea tie-ins, leak clamp installations, scheduled and unscheduled platform inspections). Readings are to be recorded in Pipe Inspection Database.

**7.1
Data Collection**

Use the following procedure to collect buried pipeline data.

Step	Activity
1	COLLECT information to the fullest extent possible, including: <ul style="list-style-type: none"> • Environment conditions • Coating conditions • Pipe conditions • Corrosion control data • Location data
2	INSPECT coating for disbonded areas and quality of coating bond, as well as cracks or general deterioration.



NOTE: If coating at the inspected location cannot be verified as well bonded over the entire pipe circumference, inspect for Stress Corrosion Cracking (SCC) in accordance with *SOP HLD.45 Wet Magnetic Particle Inspection* for crack identification.

Step	Activity
3	INSPECT internal surfaces of accessible pipes for evidence of corrosion when applicable.
4	DOCUMENT each inspection in the pipe inspection database.

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**7.2
Excavation**

Direct additional excavation, if necessary, upon discovery of a defect that extends beyond the wall of the original excavation. For example, additional excavation may be required to fully evaluate the following situations:

- Continuation of an individual corrosion pit
- Continuation of areas of general corrosion that have been determined as significant and resulted in remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline section

Continuation of mechanical defect or exposed metal surface



WARNING: In the event of a discovery of a corrosion leak or break, follow the Emergency Procedures.

**7.3
External
Corrosion
Defects**

Use the following procedure to identify external defects caused by corrosion in buried pipelines.

Step	Activity
1	EXERCISE care when evaluating corrosion defects.



NOTE: Do not remove corrosion products until a sample is collected for possible laboratory analysis.

Step	Activity
2	REMOVE the coating and thoroughly CLEAN adjacent area to the defect (abrasive blast if necessary), allowing proper measurement of the pit depth and size.



NOTE: The area that needs to be cleaned varies from defect to defect.

Step	Activity
3	EVALUATE the corrosion to determine depth of metal loss, length, and remaining wall thickness of pipe. REFER to <i>SOP HLD.47 Evaluation of Remaining Strength of Pipe with Metal Loss</i> for specifics REFER to <i>SOP HLI.11 Pipeline Pressure Limit Criteria</i> for instructions on pressure reduction requirements.
4	When an inline tool inspection indicates an anomaly and no external defect is observed, INVESTIGATE the indicated location with a UT meter. in accordance with <i>SOP HLI.34 Use of Ultrasonic Thickness Equipment for</i>

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	<i>Measurement of Wall Thickness.</i> CONSIDER using X-ray where appropriate.
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**7.4
Internal
Corrosion
Defects**

Operations Personnel uses following procedure to identify internal defects in buried pipelines.

Step	Activity
1	DEFINE the extent of the wall loss with a coarse grid UT scan to locate the defect.
	BEGIN searching for the defect at the location indicated by the in-line inspection. RECORD ranges and positions of ultrasonic readings from parent metal to deepest depth of defect.
2	EVALUATE the corrosion to determine depth of metal loss, length, and remaining wall thickness of pipe. REFER to <i>SOP HLD.47 Evaluation of Remaining Strength of Pipe with Metal Loss</i> for specifics.
3	If the readings are determined to be acceptable, DOCUMENT the defect, including a plot of the ultrasonic readings on a 1”x 1” grid, ATTACH the grid to the report form within the extent of the indication.
4	If no defect is found, VERIFY the location of the pipe joint in question.
5	If the location is correct and the defect cannot be found, CONSULT Corrosion Specialist/Supervisor to determine proper disposition of the pipe section.

**7.5
Evaluation of
Mechanical
Defects**

Evaluate any dents, scratches, gouges, arc burns, and other defects or mechanical damage in accordance with company procedures contained in *SOP HLI.06 Evaluation of Defects*.

**7.6
Field
Measurement
Qualification**

The Pipeline Engineer is responsible for the utilizing a benchmark system to qualify the accuracy of defect measurements performed in the field.

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7.7 Documentation of Inspections Operations personnel use the following steps to document the results of all pipe inspections.

Step	Activity
1	SUBMIT completed inspections in the Pipe Inspection database to the Corrosion Specialist as soon as practical, but no more than 20 days from the date of the inspection.
2	CORRECT any deficiencies identified by the Corrosion Specialist within 5 days.

8.0 Documentation Requirements Record data in electronic database or utilize the following form(s) as applicable:

- Pipe Inspection Form
- (Gforms) Pipe Inspection Database

9.0 References
HLD.45 Wet Magnetic Particle Inspection for Crack Identification
HLD.47 Evaluation of Remaining Strength of Pipe with Metal Loss
HLI.06 Evaluation of Defects
HLI.11 Pipeline Pressure Limit Criteria
HLI.I.34 Use of Ultrasonic Thickness Equipment for Measurement of Wall Thickness

Appendix A: OQ Task Requirements The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

Task Description	OQ Task
Visual Inspection of Buried Pipe and Components When Exposed	PLOQ401
Visual Inspection for Internal Corrosion	PLOQ414
Demonstrate Proper Use of Pipe Thickness Gauge (Ultrasonic)	PLOQ008