Operations Plan to Minimize Waste of Natural Gas

MarkWest Energy West Texas Gas Company, LLC

Effective Date: August 23, 2021
Revision Date: March 31, 2022

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF APPENDICES

CROSS REFERENCE TABLE

Element	Description	Section
System Overview	• General purpose overview of the gathering system	**3.0**
	• High or low pressure	**3.0**
	• PHMSA/NMPRC Regulated/Non-Regulated lines	**3.0**
	• Sweet or Sour Natural Gas	**3.0**
	• Above ground or buried lines	**3.0**
	• Installation date of lines (By Decade)	**3.0**
	• Construction Material	**3.0**
Routine Operations and Maintenance	• Physical pipeline marking and identification	**4.1**
	• Right of Way patrols, Leak surveys	**4.2**
	• Pipeline Integrity (non-exclusive list) ○ Routine pipeline inspections	**4.3**
	• Pipeline Pigging: schedule; ○ Pigging types and applications	**4.4**
	• Pipeline maintenance program (non-exlcusive list) ○ Depressurization procedures ○ Cathodic protection/anode installation ○ Pressure test and dewatering	**4.5**
	• Pressure test guidelines and schedule	**4.6**
Cathodic Protection, Corrosion Control and Liquids Management	• Cathodic protection ○ Installation on new pipelines ○ Installation or retrofit on existing pipelines ○ Monitoring and testing program to ensure effective cathodic protection	**5.1**
	• Chemical treatments	**5.1.2**
	• Fluid management – centralized vs. field dehydration	**5.2**
	• Tank Operations and Maintenance associated with the gathering system. How are the tanks managed to reduce venting and overflow events (ie. Tanks related to pigging, dehydration, etc.)	**5.3**
Procedures to Reduce Releases	• Procedures to reduce venting and flaring during maintenance, emergencies and malfunctions	**6.0**
	• Procedures for reporting scheduled maintenance and emergencies to upstream operators	**6.0**
	• Emergency response plan ○ Source elimination ○ Reporting to regulatory agencies	**6.0**

1.0 INTRODUCTION

MPLX G&P is engaged in the gathering, processing, and transportation of natural gas. MarkWest is a wholly owned subsidiaries of MPLX G&P, a diversified, growth-oriented master limited partnership that was formed by Marathon Petroleum Company (MPC) to own, operate, develop and acquire midstream energy infrastructure assets.

In accordance with the New Mexico Governor's Executive Order 2019-003, the Energy, Minerals and Natural Resources Department (ENMRD) developed and finalized rules to prevent natural gas waste from new and existing sources, requiring oil and gas operators to capture 98 percent of their natural gas waste by the end of 2026. On March 25, 2021, the ENMRD Oil Conservation Division (OCD) formally adopted The Natural Gas Waste Rules provided within New Mexico Administrative Code (NMAC) Section 19.15.27 and 19.15.28, effective as of May 25, 2021.

1.1 Purpose

Pursuant to New Mexico Administrative Code (NMAC) Section 19.15.28.8(C)(1), natural gas gathering system operators must implement an operations plan, including operational and best management practices, to minimize the waste of natural gas. For a natural gas gathering system placed into service before or on May 25, 2021, operators must submit an operations plan (the "Plan") no later than August 23, 2021.

1.2 Scope

In accordance with NMAC 19.15.28.8(C)(1), this Plan has been developed and implemented to address the natural gas gathering system and associated equipment operated by MarkWest Energy West Texas Gas Company, LLC.

1.3 Key Elements of Operations Plan

A non-exclusive list of practices is set forth in NMAC 19.15.28.8(C)(1), as follows:

- System Overview
- Routine Operations and Maintenance
- Cathodic Protection, Corrosion Control and Liquids Management
- Procedures to Reduce Releases
- Review and necessary update of the Plan

2.0 PLAN ADMINISTRATION

2.1 Commitment to Environmental Stewardship

MPLX is fully committed to ensuring public safety and protecting the environment. This commitment is outlined in MPC-MPLX's Health, Environment, Safety and Security Policy (Policy #7001). This Policy is available to all employees and readily available upon request.

MPLX has committed to provide the manpower, equipment, and engineering required to prevent venting or flaring of natural gas from a natural gas gathering system that constitutes waste as defined in 19.15.2 NMAC and is prohibited.

2.2 Management Approval of Plan

MPLX is committed to maximizing the gathering of natural gas by minimizing the waste of natural gas through venting and flaring. MPLX will take all reasonable actions to prevent and minimize leaks and releases of natural gas from its natural gas gathering system and will implement this Plan to minimize the waste of natural gas for each non-contiguous natural gas gathering system.

This Plan has the full approval of MPLX management.

The Operations Supervisor is the Designated Person Accountable for minimizing waste gas from the natural gas gathering system and has the authority to commit the necessary resources to implement this Plan.

Authorized Facility Representative (Operations District Manager): Enoc Navarro

Signature: Enoc Navarro

Title: Operations District Manager

Date: March 31, 2022

2.3 Location of Plan

The original signed Plan will be maintained at MPLX's Carlsbad office located at 5217 Sierra Vista Drive, Carlsbad, New Mexico. The Plan is maintained and managed by the MPLX Environmental Department, and copies of the Plan are readily available upon request. An electronic version of the Plan is also maintained in the MPLX network files.

2.4 Plan Review [NMAC 19.15.28]

MPLX will revise this Plan when any new pipeline is added during the calendar year or it changes its operations plan. The Plan must be reviewed at least once every year. A signed statement will be prepared by the person conducting the evaluation indicating a comprehensive review was completed and whether the Plan will be revised. Revisions made to the Plan as a result of this review will be completed and be implemented as soon as possible, but no later than March 31 of the year following the review.

A Record of Reviews is included in **Appendix A**.

3.0 SYSTEM OVERVIEW

Name of Operator:	MarkWest Energy West Texas Gas Company, LLC
OGRID:	329252
Owner:	MPLX 1515 Arapahoe Street Denver, CO 80202
Designated Responsible Party:	AJ Murray, Compression Operations Supervisor
Telephone Number (Office):	575-236-1776
Telephone Number (Cell):	575-689-5794

3.1 General Description

MPLX operates a natural gas gathering system comprised of approximately 113 miles of 4" - 20" gathering pipeline that are all located in class 1 area and 10.38 miles of 10" - 16" Federal Energy Regulatory Commission (FERC) gas transmission lines also located in class 1. The FERC pipelines are regulated by Pipeline Hazardous Material Safety Administration (PHMSA). All the pipelines are buried below ground. This system is located within Lea and Eddy County, New Mexico. A map showing the general location of the system station is presented in **Figure 1**.

The pipeline system moves sweet natural gas from exploration and production customers located within the Delaware Basin. The gathering system is currently comprised of three compressors stations and two launcher/receiver pigging sites. Ultimately the gas is delivered to two gas processing plants operating within Texas for further processing. Additional details about the system are presented **Figure 2**.

3.2 System Operations Training

Enoc Navarro

Each individual working on the MPLX pipeline system is accountable to prevent and minimize leaks and releases of natural gas from the natural gas gathering system, a responsibility communicated through training. MPLX personnel shall be trained annually in the regulatory requirements and elements of this Plan and instructed in the operation and maintenance of equipment to prevent and minimize leaks and releases of natural gas, applicable to their respective job duties. Training topics will include but not be limited to:

- On the job training, to include demonstration of successful completion of tasks
- Discussion of past events, leaks, or equipment failures and measures taken to minimize future occurrences;
- Existing and newly developed contingency procedures to be employed at the facility with in-house equipment and resources;
- Applicable regulations and coordination with other regulatory plans, as appropriate.

Records, such as sign-in sheets with meeting topics, are kept for at least three years to document the routine training programs conducted for affected personnel. Training records are also maintained electronically in the MPLX online training management system.

4.0 ROUTINE OPERATIONS AND MAINTENANCE

The following measures are implemented to minimize waste of natural gas during the handling, use, or transfer of natural gas throughout the gathering system.

4.1 Physical Pipeline Marking and Identification

In accordance 49 CFR Parts 192.707, MPLX adheres to the established Damage Prevention Program, which details pipeline right-of-way (ROW) and compressor stations marking requirements to include company contact information.

4.2 Right of Way Patrols, Leak Surveys

MPLX uses a variety of methods to patrol its natural gas gathering system (ie. Aerial, Vehicle, Foot, etc). Patrol is also used to identify leaks commonly due to external corrosion or couplings through visual indications, i.e., dead vegetation, or can be instrumented to detect natural gas. Patrol is also effective in identifying weather or outside force threats to the pipeline if the personnel are adequately trained, i.e., flooding, frost heave, indications of land movement, washouts or lightning strikes. Foot patrols are effective to identify needed pipeline marking additions or maintenance and ROW maintenance. MPLX maintains the ROW by keeping it unobstructed to reduce the risk of third-party damage and improve emergency response. This maintenance effort ensures it is stable and water drains appropriately reducing the risk of land movement impacting the pipeline. While there are currently no documented surveys on the Class 1 gathering pipelines, annual surveys are completed on FERC regulated pipelines.

4.3 Pipeline Integrity

MPLX is committed to implement and maintain an Integrity Management Program (IMP) compliant with federal and state regulations which provide a comprehensive process for managing pipeline integrity in pipeline segments and pipeline facilities that could affect high consequence areas (HCAs) to ensure public safety and the protection of the environment. MPLX's IMP ensures the integrity of gas transmission and hazardous liquid pipelines and pipeline facilities. The IMP provides the structure for continuous integration and improvement of all integrity efforts and strives to meet or exceed the requirements established compliant with federal and state regulation. The MPLX IMP overall objective is to ensure public safety and protecting the environment through continuously improving the integrity of pipelines and pipeline facilities which could affect high consequence areas. While currently none of the gathering lines within New Mexico are subject to the HCA requirements for the IMP, some aspects of the program are voluntarily applied. **Appendix B** includes the IMP Introduction that outlines all procedures included in the IMP and other MPLX documents that can be used as guidance for operating the system covered by this Plan.

When underground piping is exposed, it will be visually inspected for corrosion, leaks, and integrity of coating. Visual/mechanical inspection is typically performed per approved operation and maintenance procedures on valves and other equipment. Visual inspection is also used to verify the quality of girth welds and fabrication welds and to monitor for cold weather threats, i.e., frozen regulators.

4.4 Pipeline Pigging

The types of pigging and applications. Internal cleaning is used to remove liquids from pipeline to mitigate the risk of internal corrosion. The cleaning pigs can also be used to run batches of biocide or inhibitor. An increased frequency of cleaning pigs can reduce the buildup of corrosive products such as water and solids and reduce the impact of internal corrosion.

Another purpose for pigging is to perform in-line inspection (ILI) to identify metal loss and deformations on the pipeline. Successive ILIs can be utilized to determine corrosion growth rates and increases in deformations caused by mechanical damage and land movement over time. Performing inspections on a reduced interval can be a preventative measure. Additionally, GPS/strain monitoring processes use GPS instrumentation on ILI tools over successive runs through a line to detect and quantify movement and calculate strain induced in the line by movement. Pipeline movement can be caused by seismic activity, earth movement from landslides and subsidence, cold weather or flooding.

Currently, the pigging application and schedule used for the gathering system within New Mexico is limited to routine cleaning pigs for clearing liquids.

4.5 Pipeline Maintenance Program

The system covered by this Plan is subject to regular informal visual inspection by Operators. Operators are asked to look for: 1) Signs of deterioration, damage, or leakage; 2) In-operable pressure and safety devices; 3) Corroded piping and valves; and 4) Damaged or deteriorating piping supports. Any deficiencies are immediately investigated, and corrective action is performed.

In accordance with PHMSA requirements, MPLX has developed an Operations Maintenance Emergency Plan (OME) used to operate the FERC assets. Although the New Mexico gathering pipelines are not subject to such requirements, procedures and practices established by the OME can be applied as necessary to ensure consistent operating practices. **Table 1** summarizes sections of the OME that can be used as guidance for operating the system covered by this Plan.

Table 1 – OME Section Summary

OME Section No.	Description	Related Subsections
1.0	General	
2.0	Emergency Manual	(2.11) Gas or Liquid Release
3.0	Reporting	(3.6) Leak Grading
4.0	Conversion of Service	
5.0	Design and Construction Requirements	
6.0	Corrosion Control	
7.0	Operations and Maintenance	(7.6) Purging of Pipelines
8.0	Surveillance	(8.4) Line Patrol and Leak Survey (8.6) ROW Maintenance
9.0	Compressor Stations	
10.0	Pump Stations	
Appendix A	Emergency Contact Tables	
Appendix B	Retention Table	
Appendix C	State Reporting Guidelines	Leak Grading Procedure

4.6 Pressure Test guidelines and schedule

MPLX's policy is to conduct pressure tests as an integrity re-assessment in covered segments where pressure tests have been determined to be the integrity re-assessment method or one of the integrity re-assessment methods used to assess the identified threats to the covered segment. Baseline integrity assessments performed at construction are conducted in accordance with MPLX Pressure Testing with Water (MW-PC-1190) which satisfy requirements of 49 CFR part 192 Subpart J for gas pipelines. A copy of this standard is provided in **Appendix C**.

5.0 CATHODIC PROTECTION, CORROSION CONTROL AND LIQUIDS MANAGEMENT

MPLX's policy is to prioritize and schedule covered segments for integrity assessment according to the threat identification and risk assessment results, to select the appropriate integrity assessment method for each covered segment and schedule reassessments for each covered segment in accordance with 49 CFR Parts 192.

Inspection of pipe is required by 49 CFR Parts 192.459 for external corrosion and CFR 49 Parts 192.475(b) for internal corrosion. Expanding inspection requirements can also identify previous third party damage and address stress corrosion cracking (SCC), manufacturing or construction defects by requiring appropriate NDE, specifically in high risk areas for previously identified threats, maintenance of couplings and mitigation of wrinkle bends or buckles as required by ASME B31.8S-2010 A-5.5. Examples include screening for SCC using MPI or eddy current technology, or cracking using phased array or utilizing shear or guided wave for the inspection of pipe supports, casings, and fittings or using computed x-ray to examine elbows or drains for internal corrosion.

5.1 Cathodic protection

MPLX's policy is to conduct external corrosion direct assessment (ECDA) as an integrity assessment in covered segments where ECDA has been determined to be the selected method or one of the selected integrity assessment methods used to assess the identified threats to the covered segment.

MPLX's policy is to conduct internal corrosion direct assessment (ICDA) on covered segments transporting normally dry gas as an integrity assessment where ICDA has been determined to be the selected method or one of the selected integrity assessment methods used to assess the identified threats to the covered segment. **Table 2** summarizes standards used as guidance for operating the system covered by this Plan and copies of such are provided in **Appendix D**.

Table 2 – Engineering & Operations Standards List

Standard No.	Description	Form No.
ENG-STD-0004	Cathodic Protection for Buried and Submerged Metallic Structures	
ENG-STD-0005	Cathodic Protection for Tank Bottoms	
ENG-STD-0006	Coating of Aboveground Pipelines and Facilities Standard	ENG-STD-0006-FOR-01 ENG-STD-0006-FOR-02 ENG-STD-0006-FOR-03
ENG-STD-0007	Internal Tank Lining Standard	
ENG-STD-0008	Coating of Underground Pipe Standard	
ENG-STD-0009	Coating of Transition Areas Standard	
ENG-STD-0010	Plant Applied Coating Specification	
OPS-STD-0017	Corrosion Control Governing Standard	OPS-STD-0017-FOR-01
OPS-STD-0018	Atmospheric Corrosion Monitoring, Inspection and Mitigation	OPS-STD-0018-FOR-01
OPS-STD-0019	Internal Corrosion Monitoring and Mitigation	
OPS-STD-0020	Aboveground Cathodic Protection Surveys	OPS-STD-0020-FOR-01 OPS-STD-0020-FOR-02
OPS-STD-0021	Cathodic Protection Test Point Monitoring and Maintenance	
OPS-STD-0022	Cathodic Protection Rectifier and Interference Bond Monitoring and Maintenance	
OPS-STD-0023	Electrical Isolation Monitoring and Maintenance	OPS-STD-0023-FOR-01
OPS-STD-0024	DC Interference Monitoring and Maintenance	OPS-STD-0024-FOR-01
OPS-STD-0025	AC Interference Monitoring and Maintenance	
OPS-STD-0026	Corrosion Under Insulation Monitoring, Inspection and Mitigation	OPS-STD-0026-FOR-01
OPS-STD-0027	External Corrosion Direct Assessment	OPS-STD-0027-FOR-01 OPS-STD-0027-FOR-02 OPS-STD-0027-FOR-03 OPS-STD-0027-FOR-04 OPS-STD-0027-FOR-05 OPS-STD-0027-FOR-06 OPS-STD-0027-FOR-07
OPS-STD-0028	Stress Corrosion Cracking Direct Assessment	OPS-STD-0028-FOR-01 OPS-STD-0028-FOR-02 OPS-STD-0028-FOR-03 OPS-STD-0028-FOR-04

5.1.1 Coupon Monitoring Program

A coupon monitoring program may be internal or external. Coupons are placed external to the pipeline to determine IR free readings, evaluate AC interference, and determine native corrosion rates. Internal corrosion coupons are used to evaluate internal corrosion rates and determine effectiveness of corrosion inhibitor or biocide if used. (*See OPS-STD-0021 in Appendix D*)

5.1.2 Chemical treatments

A biocide and/or inhibitor injection program can mitigate the effects of microbiologically or chemically induced internal corrosion. This is often (but not always) combined with a coupon monitoring program to evaluate the effectiveness of the biocide or corrosion inhibitor. Coupon monitoring may be utilized to determine if biocide or corrosion inhibitor injection is necessary based on corrosion rates. (*See OPS-STD-0019 in Appendix D*)

5.2 Fluid Management

There are currently no dehydration processes operating as part of the New Mexico gathering system, therefore no fluid management applies.

5.3 Tank Operations and Maintenance

Above ground atmospheric storage tanks are operating within compressor stations located along the system. A generic compressor station process flow diagram is included in **Figure 3**. As indicated by the diagram, hydrocarbon liquids (ie. Condensate) collected throughout the process are stored in atmospheric storage tanks. Emissions from the storage tanks are routed to one or more of the following control devices: an enclosed combustion device with a destruction efficiency of 95%; or electric vapor recovery unit with similar or better control efficiency. In addition, the storage tanks are surrounded by secondary containment sufficiently impervious to contain any liquid overflows. Secondary containment is sized to hold capacity of largest container and sufficient freeboard for precipitation.

5.3.1 Inspections

Operators conduct weekly audio, visual and olfactory (AVO) inspections at each compressor station. Visual inspections of storage tanks, secondary containment, tank piping and valves, and loading and unloading areas, are also subject to more thorough inspections on a monthly basis. At a minimum, the following tank components and associated secondary containment and piping are visually inspected:

- Tank foundation and external supports
- Site gauges and level control indicators
- Overall tank condition
- Overfill protection devices
- Condition of secondary containment (presence of water) and piping
- Discharge valves
- Truck unloading areas
- Drain and load lines
- Spill Kits
- Spill containment boxes (getty boxes) for presence of oil

Weekly AVOs and monthly inspection records are maintained electronically on the MPLX network files.

5.3.2 Integrity Testing

Storage tanks are risk ranked according to a formula developed by MPLX. The external and/or internal tank integrity testing program is maintained and managed by MPLX Maintenance, Reliability and Integrity Department, and copies of associated inspection or maintenance records are readily available upon request.

Tank inspections follow standards that require bulk storage containers to be inspected on a regular schedule to assess integrity. The method and schedule of integrity testing and required qualifications for persons performing the inspections have been determined based on industry standards based on container size, configuration, and design.

6.0 PROCEDURES TO REDUCE RELEASES

MPLX has developed Leak Grading procedures to manage leaks (*Reference OME, Appendix C*). In addition, MPLX has obtained authorizations from the New Mexico Department of Environment (NMED) Air Quality Bureau to operate each compressor station in accordance with the applicable federal and state regulations. Specifically, each compressor station is currently permitted under NMED's General Construction Permit for oil and gas production, transmission, and processing facilities (GCP-O&G). Pursuant to the terms and conditions of GCP-O&G, all sources of air emissions are to be operated in a manner consistent with good air pollutant control practices for minimizing emissions, to include startup, shutdown and maintenance operations. Information related to the permits is included in **Table 3** provided below.

Table 3 – Compressor Station Air Permit Summary

Company Name	Facility Name	NMED AI#	NMED Permit#
MarkWest Tornado Gas Plant, LLC	Bell Lake North Compressor Station	350252029	9121
MarkWest Tornado Gas Plant, LLC	Mid Bell Lake Compression Station	350252128	9372
MarkWest Tornado Gas Plant, LLC	Bell Lake South Compressor Station	350251634	8253
MarkWest Tornado Gas Plant, LLC	Red Hills Compressor Station	350251700	8436

In the event of an emergency, employees shall follow procedures outlined in the company Emergency Action Plan (EAP) established in accordance with 29 CFR 1910.120 "Hazardous Waste Operations and Emergency Response", 29 CFR 1910.39 "Fire Prevention Plan" and 29 CFR 1910.38 "Emergency Action Plan". Section 3.0 of the EAP contains a list of telephone numbers that are to be used to contact the appropriate personnel or agencies in the event of an emergency. A copy of the EAP is provided in **Appendix E**.

In accordance with the EAP, MPLX personnel shall follow the in-house reporting mechanism upon discovery of a release. Management, in consultation with the local environmental professional, will use this reporting mechanism to determine when outside agencies are notified of a release. A reporting procedure flow chart showing the agencies to report to during a release event in the state of New Mexico is presented in **Figure 4**.

Notification to Affected Upstream Operators

If operating conditions should impact an upstream operator, the Operations Supervisor is the Designated Person Accountable to make notification to the appropriate upstream point of contact and record of such notification is maintained.

FIGURE 1
SYSTEM LOCATION MAP

Gathering & Processing

Central Delivery Point
Compressor Station
Gas Plant
Natural Gas - Liquids
Natural Gas
Construction Phase Pipeline

MPLX G&P
WEST TEXAS DISTRICT
OVERVIEW MAP

FIGURE 2
SYSTEM DETAILS

SYSTEM NAME	STATIONS SERIES NAME	DIAMETER	FACILITY ID	LENGTH	INSTALL TYPE	COUNTY
HOBBS	12in	12.75	fAPP2125136223	2.383790892	Below	Lea
WEST TEXAS	ABU 12in	12.75	fAPP2125136221	1.59829093	Below	Lea
WEST TEXAS	RED HILLS PAD 2 16in LP NG	16	fAPP2125136235	0.336130128	Below	Lea
WEST TEXAS	RED HILLS 12in HP DISCHARGE	12.75	fAPP2125136222	2.44817304	Below	Lea
WEST TEXAS	BELL LAKE NORTH CS GAS LIFT 8in HP NG	8.63	fAPP2125136253	1.000909275	Below	Lea
WEST TEXAS	CHEVRON DAGGER LAKE SOUTH 16in HP NG	16	fAPP2125136255	7.170027547	Below	Lea
WEST TEXAS	CHEVRON DAGGER LAKE NORTH 16in HP NG	16	NEW	8.988441313	Below	Lea
SOUTHWEST GATHERING	Wingate 1700	4.5	fAPP2125136256	13.84110076	Below	McKinley
WEST TEXAS	RED HILLS PAD 7 GAS LIFT 4in HP NG	4.5	fAPP2125136242	0.240943322	Below	Lea
HOBBS	TRANS WESTERN 12in TIE-IN	12.75	fAPP2125136239	0.225625568	Below	Lea
WEST TEXAS	CHEVRON COTTON DRAW 12in HP NG	12.75	fAPP2125136233	4.235900325	Below	Lea
WEST TEXAS	CHEVRON COTTON DRAW 16in HP NG	16	fAPP2125136226	1.585746555	Below	Lea
WEST TEXAS	RED HILLS PAD 5 12in LP NG	12.75	fAPP2125136252	0.202128295	Below	Lea
WEST TEXAS	BELL LAKE SOUTH 16in LP NG	16	fAPP2125136240	0.646702136	Below	Lea
WEST TEXAS	RED HILLS PAD 5 - 4in HPGL	4.5	fAPP2125136257	0.42547899	Below	Lea
WEST TEXAS	OXY Sand Dunes 20" HP	20	NEW	5.231768412	Below	Eddy
HOBBS	10in	10.75	fAPP2125136231	4.62587104	Below	Lea
WEST TEXAS	BELL LAKE 20in	20	fAPP2125136249	20.89781752	Below	Lea
WEST TEXAS	BELL LAKE NORTH 16in	16	fAPP2125136232	7.036231831	Below	Lea
WEST TEXAS	RED HILLS KF2 GAS LIFT 8in	8.63	fAPP2125136248	0.429996662	Below	Lea
WEST TEXAS	RED HILLS PAD 2 20in LP NG	20	fAPP2125136245	0.266189461	Below	Lea
WEST TEXAS	ROSS DRAW 12in	12.75	fAPP2125136224	0.15848417	Below	Eddy
WEST TEXAS	PREAKNESS - POKER LAKE 16in	16	fAPP2125136243	23.91507913	Below	Eddy
WEST TEXAS	BELL LAKE NORTH GAS LIFT 8in	8.63	fAPP2125136230	6.98136496	Below	Lea
WEST TEXAS	RED HILLS FACILITY PAD 1 12in LP NG	12.75	fAPP2125136225	0.48497161	Below	Lea
WEST TEXAS	BELL LAKE NORTH CS 16in LP NG	16	fAPP2125136237	0.90931113	Below	Lea
WEST TEXAS	RED HILLS 12in LP NG EXTENSION	12.75	NEW	0.431810295	Below	Lea
HOBBS	NORTH 16in	16	fAPP2125136250	1.521503178	Below	Lea
WEST TEXAS	RED HILLS 12in HP	12.75	fAPP2125136247	0.422963764	Below	Lea
WEST TEXAS	RED HILLS KF1 GAS LIFT 8in	8.63	fAPP2125136244	0.190079597	Below	Lea
WEST TEXAS	BELL LAKE NORTH CS 12in HP NG DISCHARGE	12.75	fAPP2125136228	0.890138295	Below	Lea
WEST TEXAS	ALADDIN 12in	12.75	fAPP2125136238	1.324566755	Below	Lea
WEST TEXAS	RED HILLS PAD 6 GAS LIFT 4in HP NG	4.5	fAPP2125136234	0.052660052	Below	Lea
WEST TEXAS	RED HILLS PAD 8 GAS LIFT 6in HP NG	6.63	fAPP2125136227	0.769194001	Below	Lea
WEST TEXAS	MIDDLE GROUND 16in LP NG LATERAL	16	fAPP2125136229	0.208248666	Below	Lea
HOBBS	SOUTH 16in	16	fAPP2125136254	1.627431286	Below	Lea
WEST TEXAS	TORNADO 20in	20	fAPP2125136251	16.70158035	Below	Eddy
WEST TEXAS	SALADO DRAW 1 & 2 16in NG	16	fAPP2125136241	6.572707954	Below	Lea
SOUTHWEST GATHERING	Bisti 8 Inch 502	8.63	fAPP2125136246	96.28683946	Below	San Juan
WEST TEXAS	RED HILLS 16in LP KF1	16	fAPP2125136236	0.641481246	Below	Lea
WEST TEXAS	CHEVRON SAND DUNES 20in HP NG	20	NEW	4.357532917	Below	Eddy
WEST TEXAS	BELL LAKE NORTH 16in LP NG	16	NEW	0.123106679	Below	Lea

FIGURE 3
COMPRESSOR STATION PROCESS FLOW DIAGRAMS

Process Flow Diagram for the Mid Bell Lake Compressor Station

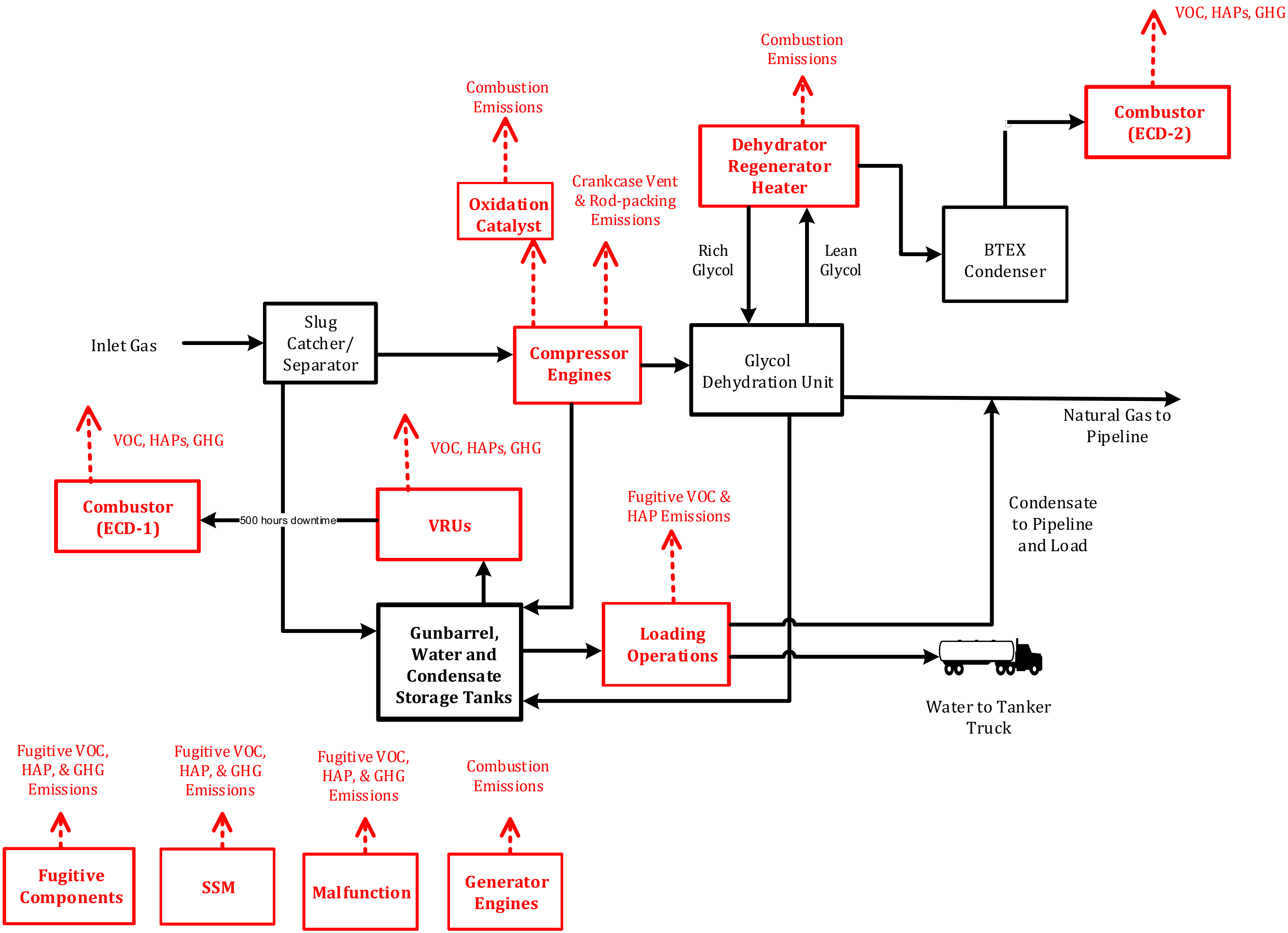


FIGURE 4
RELEASE EPORTING FLOW CHART

New Mexico Release Notification Guide

Initial Reporting Responsibility

Initiate MAPLINE

Communicate the event to the GSOC Operator to have them initiate Notification List
*GSOC refer to local Operations Guide

Provide Incident Details

Communicate Spill/Release details to Environmental/DOT Compliance Staff

Evaluate Release Reporting

Check ALL boxes that apply to the spill event

Is the event a reportable release?

YES → **Environmental/DOT Compliance Staff will notify External Agency** → **Enter into Intelex**

NO → **Enter into Intelex**

*Incident details must be entered within 48 hours by trained SWG staff

New Mexico LEPC			
Albuquerque/Bernalillo County (505) 750-7681	Eddy County (575) 628-5450	Lincoln County (575) 808-1381	Rio Arriba County (505) 747-1941
Chaves County (575) 624-6740	Lea County (575) 391-2983	McKinley County (505) 722-4248	San Juan County (505) 334-1180

CERCLA Reportable Quantities (24hr period)				
Benzene 10 lbs	Ethyl Benzene 1000 lbs	N-Hexane 5000 lbs	Toluene 1000 lbs	Ethylene glycol 5000 lbs
Cyclohexane 1000 lbs	Hydrogen Sulfide 100 lbs	Naphthalene 100 lbs	Xylenes 100 lbs	Potassium Hydroxide 1000 lbs

Updated May 2021

Reportable Releases / Reporting Requirements / External Agency Contacts

- ❑ Impacted or threatened to impact waters of the state (sheen)
- ❑ Spill volume exceeded a CERCLA reportable quantity (see table below) **to a permeable surface**

→ Report spill **verbally,** as soon as **practicable**, but no later than within 24 hours of discovery. → **National Response Center** 800-424-8802

- ❑ Spill from stationary source **AND** resulted in fatality, serious injury, or $1M property damage

→ Report spill within 8 hrs of discovery. *For CERCLA RQs, Report spill within 30 mins of NRC notification → **Chemical Safety Board** 202-261-7600 or e-mail to: report@csb.gov

- ❑ Posed imminent threat to human life, health or the environment
- ❑ Spill volume exceeded a CERCLA reportable quantity (see table below) **to a permeable surface**

→ Report spill **verbally,** as soon as **practicable**, but no later than within 24 hours of discovery. → **New Mexico Local Emergency Planning Committee** See LEPC Contacts

- ❑ Spill volume equals or exceeds **25 gallons** of a petroleum product from non-exempt Petroleum Storage Tank
- ❑ Impacted or threatened to impact waters of the state (sheen)
- ❑ Spill volume exceeded a CERCLA reportable quantity (see table below) **to a permeable surface**

→ Report spill **verbally, as soon as practicable**, but no later than within 24 hours of discovery. *Follow up with **written report** within **14 days.*** → **New Mexico Environment Department**
- 866-428-6535
- 24-hour Line (505) 827-9329

- ❑ Spill volume equals or exceeds **100 bbls** of oil, salt water, or oil waste **outside of containment** on BLM land, or fire that consumes 100 bbls
- ❑ Spill impacted or occurred in a sensitive area* on BLM land **inside OR outside containment**

→ Report spill **verbally,** as soon as **practicable**, but no later than within 24 hours of discovery. *Follow up with **written report** and required **BLM form** within **15 days.*** → **New Mexico Bureau of Land Management**

* Sensitive Areas include parks, recreation sites, wildlife refuges, lakes, reservoirs, streams, and urban/suburban areas.

- ❑ Spill volume **between 10 and 100bbls** of oil, salt water, and oil waste **outside containment** on BLM land
- ❑ Spill volume **100 bbls or more** and is located **inside of the containment** on BLM land

→ Submit **written report** of spill within **15 days** of discovery. → **New Mexico Bureau of Land Management**
- Farmington (505) 564-7600
- Albuquerque (505) 761-8700
- Roswell (575) 627-0272
- Carlsbad (575) 234-5972

- ❑ Spill volume **between 5 and 25 bbls** of any fluid

→ Submit **written report**, Form C-141, of spill within **15 days** of discovery. → **New Mexico Oil Conservation Division**

- ❑ Spill volume **equals or exceeds 25 bbls** of any fluid
- ❑ Impacted or threatened impact to waters of the state, human life, public health, or environment
- ❑ Results in fire

→ Report spill **verbally or by email through form C-141 as soon as practicable,** but no later than 24 hours of discovery.

Follow up with a written report, *Form C-141,* submit within **15 days of discovery.** → **New Mexico Oil Conservation Division**
- Hobbs (575) 370-3186
- Artesia (575) 626-0830
- Santa Fe (505) 476-3441
- Aztec (505) 334-6178

- ❑ ** for DOT (intrastate & interstate) pipeline accidents*
  - A. Spill volume **equals or exceeds 5 gals** and is **not related to** a DOT (PHMSA) pipeline maintenance activity
  - B. Spill volume **equals or exceeds 5 bbls** and **is related to** a DOT (PHMSA) pipeline maintenance **activity**
  - **C. Explosion** or **fire** not intentionally set by operator
  - **D. Death** of any person **and/or personal injury** necessitating **hospitalization**
  - **E. Costs** of damage, clean-up/recovery, lost product **exceeds $50,000**

→ **C, D, E - Report spill verbally within 1 hour of discovery.**

Submit a written report, *DOT (PHMSA) Form 7000-1*, within **30 days of discovery.**

→ ***interstate pipeline***
National Response Center
800-424-8802

intrastate pipeline
NM PRC—Pipeline Safety
(505) 490-2375

APPENDIX A

RECORD OF REVIEW

Date	Reviewer Name (Print)	Reviewer Signature	Remarks	Amendment Required (Y/N)
3-31-2022	Jessica O'Brien	Jessica O'Brien	Update to contacts and system map, incorporated additional assets	☑ Yes ☐ No
				☐ Yes ☐ No
				☐ Yes ☐ No
				☐ Yes ☐ No
				☐ Yes ☐ No

APPENDIX B
IMP INTRODUCTION

POLICY

MPLX Gathering and Processing (MPLX G&P) (MarkWest Energy Partners, L.P., Andeavor Logistics and Southwest Gathering) is committed to implement and maintain an Integrity Management Program (IMP) compliant with federal and state regulations which provide a comprehensive process for managing pipeline integrity in pipeline segments and pipeline facilities that could affect high consequence areas (HCAs) to ensure public safety and the protection of the environment.

PURPOSE AND DISCUSSION

The purpose of this procedure is to present the MPLX Gathering and Processing IMP goals and overview of the IMP process which is designed to continually change and improve with modifications to the pipeline systems, changes in industry standards, company and industry experience and advances in integrity management technologies.

APPLICABLE REGULATIONS AND STANDARDS

Refer to Section 6.0

INTEGRITY MANAGEMENT PLAN PROCEDURES

IMP 01 *IMP Introduction*

IMP 02 *HCA Identification*

IMP 03 *Data Management*

IMP 03.A1 *Required Data Table*

IMP 04 *Threat Identification and Risk Analysis*

IMP 04.A1 *Threat Identification Justification*

IMP 04.A2 *Crack Management*

IMP 05 *Preventive and Mitigative Measures*

IMP 05.A1 *Preventive and Mitigative Measures Matrix*

IMP 05.A2 *Preventive and Mitigative Measures Descriptions*

IMP 05.1 *Leak Detection and Analysis*

IMP 05.2 *Emergency Flow Restriction Devices Analysis*

IMP 05.3 *Valve Response Analysis*

IMP 06 *Integrity Assessment*

IMP 06.1 *In-Line Inspection*

IMP 06.2 *Pressure Test*

IMP 06.3 *ECDA*

IMP 06.4 *ICDA*

IMP 06.5 *SCCDA*

IMP 07 *Condition Remediation*

IMP 07.*A1 Gas Categorization of Anomalous Conditions*

IMP 07.A2 *Hazardous Liquid Categorization of Anomalous Conditions*

IMP 08 *Management of Change*

IMP 09 *Quality Control*

IMP 09.A1 *IMP Process*

IMP 09.A2 *IMP Qualification Requirements*

IMP 10 *Communication*

IMP 11 *Performance Measurement*

QUALIFICATIONS

Company and contract personnel who perform IMP related functions are qualified per applicable IMP procedures.

DEFINITIONS

Gas pipelines are pipelines subject to DOT 49 Code of Federal Regulations (CFR) Part 192 and state regulations, as applicable.

Gas[1] is natural gas, flammable gas or gas which is toxic or corrosive.

HCA is a high consequence area as defined in IMP 02 *HCA Identification*.

Hazardous liquids[2] are petroleum, petroleum products, anhydrous ammonia and ethanol or other non-petroleum fuel, including biofuel, which is flammable, toxic, or would be harmful to the environment if released in significant quantities.

Liquid pipelines are hazardous liquids pipelines or carbon dioxide pipelines subject to DOT 49 Code of Federal Regulations (CFR) Part 195

PHMSA is the Department of Transportation's (DOT) Office of Pipeline Safety's (OPS) Pipeline and Hazardous Material Safety Administration

[1] 49 CFR 192.3
[2] 49 CFR 195.2

PROCEDURE TO INTRODUCE IMP

1.0 COMPANY DESCRIPTION

1.1. MPLX G&P is engaged in the gathering, processing, and transportation of natural gas, the transportation, fractionation, storage and marketing of NGLs, and the gathering and transportation of crude oil. MarkWest, Andeavor Logistics and Southwest Gathering are wholly owned subsidiaries of MPLX G&P, a diversified, growth-oriented master limited partnership that was formed by Marathon Petroleum Company (MPC) to own, operate, develop and acquire midstream energy infrastructure assets.

2.0 IMP COMMITMENT

2.1. MPLX is fully committed to ensuring public safety and protecting the environment. MPLX IMP ensures the integrity of gas transmission and hazardous liquid pipelines and pipeline facilities. The IMP provides the structure for continuous integration and improvement of all integrity efforts and strives to meet or exceed the requirements established compliant with federal and state regulation.

3.0 IMP GOALS

3.1. The MPLX IMP overall objective is to ensure public safety and protecting the environment through continuously improving the integrity of pipelines and pipeline facilities which could affect high consequence areas.

3.2. Additional sections of this IMP include procedures used to assess gas DOT regulated transmission pipelines greater than 30% SMYS that have been determined to be outside of an HCA and are in a Class 3 or are in a Moderate Consequence Area.[3] Additional sections also include procedures used to assess liquid DOT regulated transmission pipelines that do not affect HCA's.[4] Those applicable procedures are the following:

3.2.1. HCA

3.2.2. Threat Identification and Risk Analysis

3.2.3. Condition Remediation

3.2.4. Integrity Assessment

4.0 COMPANY SYSTEM DESCRIPTION

4.1. MarkWest, Andeavor Logistics, and Southwest Gathering are wholly owned subsidiaries of MPLX G&P, and are engaged in the gathering, processing, and transportation of natural gas; the transportation, fractionation, storage and marketing of NGLs; and the gathering and transportation of crude oil. The pipeline

[3] 49 CFR 192.710
[4] 49 CFR 192.416

and pipeline facilities include intrastate, interstate and FERC regulated. For specific information regarding the pipelines and pipeline facilities in the Integrity Management Plan, and pipelines subject to the 10-year assessment requirements of 192.710 and 195.416 refer to the *IMP Covered Segment Summary.*

5.0 COMPANY PROGRAMS AND PROCEDURES

5.1. The following includes the operations, maintenance and emergency (OME) procedures, programs and forms that are referenced in the IMP generically as MPLX.

5.1.1. MPLX Operations, Maintenance and Emergencies Manual

5.2. The following are the MPLX programs that are referenced in the IMP.

5.2.1. MPLX *Public Awareness Program*

5.2.2. MPLX *Damage Prevention Program*

5.2.3. MPLX *Operator Qualification Program*

5.2.4. MPLX *Control Room Management*

5.2.5. MPLX *Pipeline Management of Change*

6.0 REGULATIONS AND STANDARDS The following federal/state regulations, standards and other source documents are used to develop and maintain the IMP:

6.1.1. 49 Code of Federal Regulations (CFR) Part 192 Subpart O, August 25, 2017, including Gas IMP Frequently asked questions (FAQs), February 22, 2016, and Gas IMP inspection protocols, May 2015,

6.1.2. 49 Code of Federal Regulations (CFR) Part 195.452 and Appendix C to Part 195 – Guidance for Implementation of an Integrity Management Program, August 25, 2017, including Liquid IMP Frequently asked questions (FAQs), August 31, 2016 and Liquid IMP inspection protocols, May 2015,

6.1.3. Applicable State Regulatory Agencies which may supersede federal regulations; Oklahoma Corporation Commission or OCC (OAR Title 165. Chapter 20.), Railroad Commission of Texas or TRRC (TAC Title 16. Part 1. Chapter 8. Subchapter B. Rule 8.101), Public Utilities Commission of Ohio or PUCO (OAC Chapter 4901:1-16), Pennsylvania Public Utility Commission or PUC), New Mexico Oil Conservation Division (19.15.28.8 (C)(1) NMAC) and Public Service Commission of West Virginia or WVPSC (WVC Chapter 24B.). At this time, only the TRRC regulations address Integrity Management by mandating all Gas Transmission and Hazardous Liquid pipelines and pipeline facilities with an MAOP/MOP of 100 psig or greater are included in an Integrity Management Plan if prescriptive based, and New Mexico state statute 19.15.28 NMAC which requires procedures include integrity management of gas gathering pipelines as necessary to prevent and minimize leaks and releases of natural gas.

6.1.4. ANSI/ASNT ILI-PQ-2005(2010), "*In-line Inspection Personnel Qualification and Certification*" reapproved October 11, 2010, as incorporated by reference per 49 CFR 195.3 (ANSI/ASNT ILI-PQ),

6.1.5. API 1160, *Managing System Integrity for Hazardous Liquids Pipelines*, 3rd edition February 2019, which is not incorporated by reference and used as guidance (API 1160),

6.1.6. API 1163, *In-Line Inspection Systems Qualification* Second edition, April 2013, Reaffirmed August 2018 as incorporated by reference per 49 CFR 195.3 and 49 CFR 192.7 (API 1163),

6.1.7. API 1176, Recommended Practice for Assessment and Management of Cracking in Pipelines 1st edition, June 2016, which is not incorporated by reference and used as guidance (API 1176),

6.1.8. API 1178, Integrity Data Management and Integration, 1st edition, November 2017 (API Bulletin 1178)

6.1.9. API 1183, Assessment and Management of Pipeline Dents 1st edition, November 2020, which is not incorporated by reference and used as guidance,

6.1.10. ASME/ANSI B31G-1991 (Reaffirmed, 2004), *Manual for Determining the Remaining Strength of Corroded Pipelines* as incorporated by reference per 49 CFR 192.7 and 195.3 (ASME B31G),

6.1.11. ASME/ANSI B31.4-2006 *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* as incorporated by reference per 49 CFR 195.3 (ASME B31.4),

6.1.12. ASME/ANSI B31.8S-2004, *Supplement to B31.8 on Managing System Integrity of Gas Pipelines* as incorporated by reference per 49 CFR 192.7 (ASME B31.8S),

6.1.13. NACE SP0102-2010, *Standard Practice, Inline Inspection of Pipelines* as incorporated by reference per 49 CFR 195.3 and 49 CFR 192.7 (NACE SP0102),

6.1.14. NACE SP0206-2006, *Standard Practice, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas* which is not incorporated by reference and used as guidance (NACE SP0206),

6.1.15. NACE SP0204-2008, Standard Practice, Stress Corrosion Cracking (SCC) Direct Assessment Methodology as incorporated by reference per 49 CFR 195.3 (NACE SP0204), 6.1.16. ANSI/NACE SP0502-2010, *Standard Practice, Pipeline External Corrosion Direct Assessment Methodology* as incorporated by reference per 49 CFR 192.7 and 195.3 (NACE SP0502),

6.1.17. GRI 02-0057-2002 Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology as incorporated by reference per 49 CFR 192.7 (GRI 02-0057).

6.1.18. AGA, Pipeline Research Committee Project, PR - 3 -805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR - 3 - 805 (R - STRENG))

6.1.19. American Society of Testing and Materials (ASTM) E 1049-85, Standard Practices for Cycle Counting in Fatigue Analysis, Reapproved in 2011

6.1.20. Baker, M., Office of Pipeline Safety (OPS) TTO-05, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation. USDOT Research and Special Programs Administration, April 2004.

6.1.21. Baker Jr., M., Stress Corrosion Cracking Study, Prepared for the US Department of Transportation Office of Pipeline Safety, September 2004

6.1.22. Beavers, J. A. et al., Methodology for Ranking SCC Susceptibility of Pipeline Segments Based on the Pressure Cycle History, NACE, Corrosion 2007 Conference and Expo, March 2007

6.1.23. NACE, External Stress Corrosion Cracking of Underground Pipelines, NACE Technical Committee Report, 2003

6.1.24. J. F. Kiefner and K. M. Kolovich, Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams, Final Report, Kiefner and Associates, Worthington (Ohio), January 3, 2013

7.0 IMP PROCESS

7.1. The IMP consists of the following main program elements:

7.1.1. IMP Introduction per IMP 01 *IMP Introduction*

7.1.2. HCA Identification per IMP 02 *HCA Identification*

7.1.3. Data Management per IMP 03 *Data Management*

7.1.4. Threat Identification and Risk Analysis per IMP 04 *Threat Identification and Risk Analysis*

7.1.5. Preventive and Mitigative Measures per IMP 05 *Preventive and Mitigative Measures*

7.1.6. Integrity Assessment per IMP 06 *Integrity Assessment*

7.1.7. Condition Remediation per IMP 07 *Condition Remediation*

7.1.8. Management of Change per IMP 08 *Management of Change*

7.1.9. Quality Control per IMP 09 *Quality Control*

7.1.10. Communication per IMP 10 *Communication*

7.1.11. Performance Measurement per IMP 11 *Performance Measurement*

7.2. Processes included in the IMP are provided in the IMP procedures and other MPLX operating, maintenance and emergency (OME) procedures as specified in the related procedures section in each of the IMP procedures as well as specific MPL procedures that are referenced where services are shared.

8.0 IMP TEAM ROLES AND RESPONSIBILITIES

8.1. Responsibilities for implementation of the IMP are specified in each IMP procedure in the Responsibility statements. The following also apply:

8.1.1. The EVP, Chief Operating Officer will serve as the senior executive officer sponsor of the IMP and will sign and certify required IMP reports prior to submittal to PHMSA per IMP 10 *Communication*.[5]

8.1.2. The Senior Vice President of Operations will provide support for the IMP.

8.1.3. The Engineering Manager – Pipeline Integrity is responsible for the oversight and management of the IMP.

8.1.4. The Integrity Department and the Integrity Committee are responsible for the implementation of IMP and procedures, annual review of the IMP and recommendations for improvement.

[5] PIPELINE Acts 2006 §16

REVISION HISTORY

MOC	Rev #	Rev Date	Comment
	1.0	4/2018	• New Procedure
	2.0	2/2019	• Add Public Utilities Commission of Ohio and Pennsylvania Public Utility Commission to 6.1.3
	3.0	7/1/2020	• Updated company description to MPLX Gathering and Processing with logo and defined its subsidiaries as Markwest Energy Partners and Andeavor Logistics • Added legacy Andeavor reference documents as sources for IMP development and maintenance as processes and procedures begin merging • Update to include requirements of 192.710 and 195.416 Integrity Assessments of areas outside high consequence areas
	3.1	2/15/2021	• Incorporating SWG into IMP, adjusting language to handle multiple regions/processes until unified under oneMPLX • Added IMP 04.A2 Crack Management, API RP 1163, 1176, 1178, 1183 as reference sources, removed reference to CEPA and NEB as outdated sources • Updated roles and responsibilities
	3.2	8/20/2021	• Definition of Gas Pipeline amended • Amended 6.1.3 to include New Mexico state regulation

APPENDIX C
MPLX PRESSURE TESTING WITH WATER

Pressure Testing with Water

MARKWEST Energy Partners, L.P.

Section No.: MW-PC-1190

Subject: Construction Standards **Date Issued:** 9/4/2015 **Date Revised:** 07/13/2017 **Date Printed:** 8/23/2021
Pipeline Construction Manual **Revision 1.4**

Pressure Testing with Water

Table of Contents

1. Scope

This document defines Company requirements for pressure testing of new and existing pipeline with water. Pressure testing with other media is covered in MW-PC-1191 Pressure Testing with Other Media.

2. Regulations and Standards for Construction

2.1. Relevant regulations and standards are located in Subsection 2 of MW-PC-1000 General Conditions. Contractor is also required to comply with the most recent version of the following additional regulations and references:

- 49 CFR Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, especially Subpart J *Test Requirements*, §192.619 *Maximum allowable operating pressure: steel or plastic pipelines*, and §192.620 *Alternative maximum allowable operating pressure for certain steel pipelines*
- 49 CFR Part 195 – Transportation of Hazardous Liquids by Pipeline, especially Subpart E *Pressure Testing*
- American Society of Mechanical Engineers (ASME) B31.3 – Process Piping
- ASME B31.4 – Pipeline Transportation Systems for Liquids and Slurries

- ASME B31.8 – Gas Transmission and Distribution Piping

2.2. Company documents related to this Construction Standard:

- MW-PC-1191 Pressure Testing with Other Media
- Company Safety Procedures

3. Pressure Testing Steel Pipe – General

3.1. The Company Representative or Project Engineer shall review and approve a detailed pressure test plan and any proposed test plan deviations and submit test design parameters to Contractor using Liquid Pipeline Facilities Pipeline Pressure and Test Report.

3.2. Contractor shall abide by test design parameters and any other test requirements set by Company. Any changes to test design parameters shall be approved by the Company Representative or Project Engineer before testing operations may commence.

3.3. Contractor shall notify the Company Representative of any schedule changes as soon as such changes are known and before commencement of testing operations.

3.4. The Company Representative shall be present during all testing operations.

3.5. All piping components should be identified by size, wall thickness, seam type, grade, and elevation profile. All connections shall have proper American National Standards Institute (ANSI) ratings including flange rating and the stationing of all pipeline valves, equipment, blinds, closures, air vents, and other connections to the segment that will be exposed to the test pressure.

3.6. Test pressures shall be provided in the Scope of Work or construction drawings.

3.7. All pressure testing durations and minimum test pressures shall meet the minimum requirements outlined in Onshore Natural Gas Pipeline Pressure and Leak Test Requirements (Appendix A).

3.8. Pressure testing of valves should be performed according to any procedures provided by the manufacturer. If no such procedures exist for ball valves or gate valves, they should be in the fully open position when the injection of test fluid begins. This will allow any pipeline debris to be flushed through the valve bore.

Once the piping system has been filled completely with the test fluid, the valve should be placed in the half open position. This allows test fluid into the body cavity of the valve. The valve is now ready to be pressure tested.

After completion of hydrostatic testing, the valve should be returned to the fully open position before removing the test fluid from the piping system. The test fluid in the body cavity shall be drained through the body drain port located on the lower portion of the valve body.

3.9. Major directional bores, railroad crossings, and cased crossings should be pre-tested prior to installation.

3.10. For pre-fabricated assemblies, pressure test results should be reviewed and accepted by the Company Representative prior to shipment.

3.11. If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required if the manufacturer certifies that either the component was tested to at least the pressure required for the pipeline to which it is being added or the component carries a pressure rating established through applicable ASME/ANSI or Manufacturers Standardization Society (MSS) specifications or by unit strength calculations.

3.12. If Company applies for permits, the Company Environmental Representative shall provide Contractor with a copy of the withdrawal/discharge permits for hydrostatic test water. If Contractor applies for permits, said Contractor shall provide Company with copies of approved permits. Water withdrawal/ discharge permit copies shall be maintained on site at all times during testing operations.

3.13. Any water obtained or discharged shall comply with permit requirements.

3.14. The Company Environmental Representative shall ensure that all testing operations are in compliance with applicable permits. Required water samples shall be obtained from each source to allow time for lab analysis and documentation in accordance with federal and state regulations. This ensures water quality before the line is filled and again before ultimate disposal occurs. Contractor shall not discharge water to any locations other than those approved by permits.

3.15. Under no circumstances shall an alternate water source be used without prior authorization from the Company Environmental Representative and permit revisions.

3.16. Whenever water sampling is required, sample bottles shall be obtained from a certified testing laboratory. Analysis of the samples shall be in accordance with permit requirements. Each bottle shall be marked with:

- Source of water with pipeline station number;
- Date taken;
- Laboratory order number; and
- Name of person taking sample.

3.17. Contractor shall ensure that water used for testing does not freeze.

3.18. Contractor shall provide all labor, equipment, material, services, and supervision to perform complete pressure testing, including, but not limited to:

- High volume centrifugal pumps capable of filling pipeline with water at a rate that prevents inclusion of air in the test section. For larger projects, 500-1,200 gallons per minute at static pressures of 500 psig is recommended. Smaller projects shall have pumps sized to fill the line in a reasonable length of time;

- A variable speed, positive displacement pressure pump capable of pumping and pressuring line to a minimum of 200 psig in excess of maximum specified endpoint test pressure. The pump shall be capable of maintaining a constant and uniform pressurization rate and shall be capable of a minimum range of one (1) gallon to 75 gallons per minute at test pressure. The pump shall be equipped with a solenoid type stroke counter or meter to measure the amount of test liquid added during pressuring or removed from the pipeline;

- A flow meter sized to measure maximum test water fill rate. The flow meter shall be of a type and capacity to measure water volumes to within 0.5% of manufacturer specifications;

- Deadweight balance testers and backup unit(s) with individual weights for measuring up to the specified endpoint test pressures in maximum increments of one (1) psig. A certified digital pressure gauge may be substituted for deadweight in all tests as long as the requirements for certification and accuracy specified below are satisfied. Sensitivity of certified digital pressure gauge or deadweight shall be 0.5 psig or 0.1% of reading, whichever is greater. The Project Engineer may approve the use of other pressure measurement devices;

NOTE	
	Throughout this document, references to deadweight are to be inferred to mean either a deadweight balance tester or a certificated digital pressure gauge.

- Pressure recording devices shall be recalibrated at least annually unless directed otherwise by the Company Representative. The calibration records shall be provided prior to each test;

- Pressure recorders covering a minimum 24-hour range with an eight (8) inch minimum diameter chart size or eight (8) inch minimum chart width for strip recorders. Pressure recorders shall be capable of measuring a 0 to 3,000 psig range or range designated by the Company Representative. The Project Engineer may approve the use of other pressure recorders;
- Six (6) inch minimum diameter Bourdon pressure gauges with marked pressure increments capable of measuring the full range of specified test pressures;
- Temperature recorders and thermometers covering a minimum 24-hour range and capable of measuring temperatures from 0°F to 150°F, readable to 1°F. A minimum of one recorder is required; however, more may be added as deemed necessary by the Company Representative;
- Electronic temperature measuring devices (i.e., millimeters, digicators, thermoelectric pyrometers, thermocouples, resistance temperature detectors, thermistors, etc.) shall be attached to the pipeline during hydrostatic testing when required by the Company Representative. These devices shall be capable of measuring temperature to the nearest 0.5°F;
- Air compressors capable of propelling cleaning, dewatering, and drying pigs at recommended rates that will clean the pipeline. Compressors shall be capable of overcoming static head pressures during dewatering and transfer operations;
- Strainers/filters for use in the water supply line intake with a minimum 100 mesh screen and/or cartridge (to prevent pumping foreign materials into pipeline);
- Test header/receiver designs as pre-approved by the Company Representative;
- Cleaning, filling, and dewatering pigs in conformance with the Scope of Work;
- Splash plates and/or energy diffusers for disposal lines;
- Temporary piping, fittings, valves, flanges, gaskets, bolts, and all other test apparatus required for temporary water lines for fill and/or disposal;
- Clean water transfer tanks (for flushing and discharging water) which hold water volumes capable of avoiding shutdown of water pumps between water load deliveries; and
- Clean tank trucks or vessels to transport source water to the test site (to prevent source water contamination).

3.19. When required by the Project Manager or when specified in the Scope of Work, Contractor shall provide an enclosed, lighted, heated, and/or air conditioned shelter sized to house pressure recorders, deadweights, and personnel at the data procurement site of each test section (during complete cleaning, filling, pressuring, testing, and water disposing operations). Contractor shall provide approved lighting for otherwise non-illuminated areas during cleaning, pressuring, testing, and drying operations.

3.20. Test equipment shall have been certified for accuracy within the prior 12 months by an independent test lab. Certifications of said test equipment shall be provided to the Company Representative a minimum of 72 hours prior to commencing hydrostatic testing operations. Company retains the right to reject use of any equipment that appears subject to improper handling or is not functioning correctly. Deadweight and digital gauge calibration shall be traceable to the U.S. Bureau of Standards.

3.21. When test pressures develop hoop stress near the specified minimum yield strength (SMYS) of the pipe, the double stroke method shall be used in order to prevent the pipe from overstraining. See Paragraph 3.22 for details about the double stroke method.

3.22. When test design exceeds 90% SMYS, the double stroke method shall be used. The double stroke method determines yield using pressure at the lowest elevation within the section being tested at which the number of pump strokes per increment of pressure rise becomes double the number of pump strokes per increment of pressure rise that was required during the straight line part of the pressure-volume plot before any deviations occur. The pressure-volume plot shall start when hoop stress reaches 85% SMYS and continue for the duration of the test.

3.23. A 24-hour pressure recorder and pressure gauge shall be manifolded and installed at the shelter, the pressure site, or other areas designated by the Company Representative. At the pressuring site, a deadweight tester shall be included in the manifold. Manifolds shall be installed so that each instrument may be isolated from other instruments.

3.24. Temperature recorders shall be located at the shelter area, the pressure site, or other areas designated by the Company Representative. Recorders shall be located to avoid effects of ambient temperatures or changes in injection fluid temperature due of proximity of injection pump.

3.25. Externally mounted temperature bulbs (for pipeline test sections) shall be secured directly to the lower half of exposed pipe and insulated from weather elements before the line is filled with water.

3.26. Test hose or temporary piping shall be rated for a minimum of the test pressure; hose or piping without factory pressure rating stenciling shall not be used.

3.27. Unless otherwise specified in the Scope of Work, Contractor shall provide, inspect, repair, and maintain all test heads as outlined below:

3.27.1. Prior to commencing hydrostatic testing operations, the Company Representative and Contractor shall inspect test heads to confirm that all components are in good condition and meet working pressure requirements.

3.27.2. Before each hydrostatic test, Contractor shall inspect test heads/ manifolds to ensure that no components (including gaskets, O-rings, fittings, and valves) will leak or cause loss of test water and that all components conform to specified safety requirements.

3.27.3. Unless otherwise specified, Contractor shall provide detailed drawings and material specifications (for each test header) to the Company Representative for review before use.

3.28. Contractor shall complete all test records, charts, instrument certifications, and related forms. Both Contractor and the Project Engineer shall sign all test records, charts, instrument certifications, and related forms.

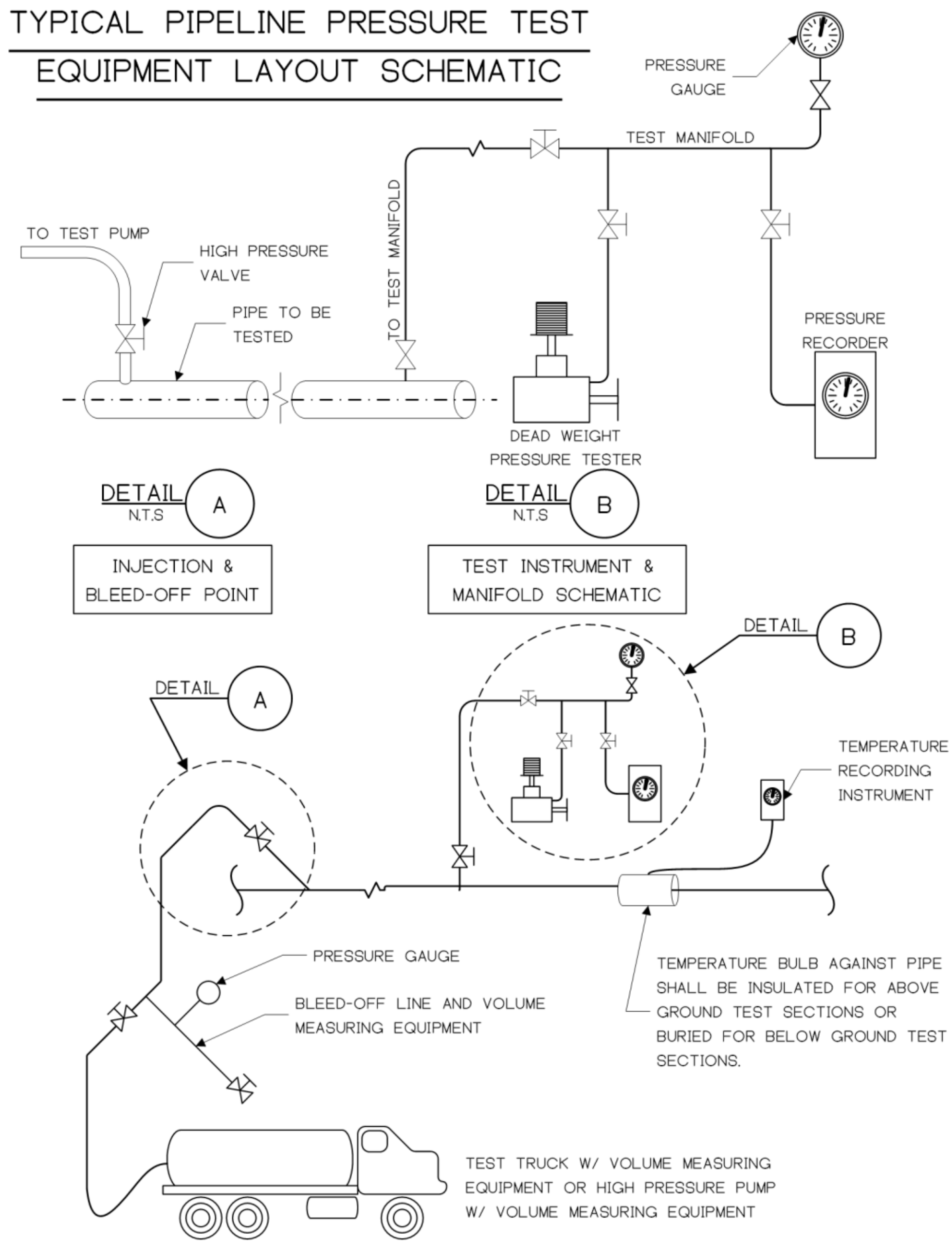


Figure 1190.1. Pipeline Pressure Test Equipment Layout Schematic

4. Safety Concerns

Existing safety regulations pertaining to work areas, safety devices, and work practices are not intended to be replaced by the following safety requirements.

During test operations, Contractor shall provide for the safety of the public and all pipeline construction personnel with the following measures:

4.1. Place warning signs in or near populated areas.

4.2. Check all hoses, fittings, connectors, and valves for proper pressure rating.

4.3. Non-essential personnel and equipment (test shelters, manifolds, compressors, pressurized cylinders, tank trucks, instruments, etc.) should be kept a minimum of 300 feet from the test site.

4.4. Test equipment and personnel shall be positioned to minimize potential hazards. Typical positioning should include a barrier between the test equipment and test manifold and/or placement of the test equipment a minimum distance of 25 feet from the test manifold.

4.5. Major pipeline work around pipeline sections being tested should be minimized during test operations.

4.6. Major pipeline work around pipeline sections being tested is prohibited when such work is not directly associated with test operations.

4.7. Contractor shall provide and maintain reliable transportation and communication systems during test operations whereby all personnel directly involved in testing may communicate during testing.

4.8. All lines and hoses shall be restrained and secured. Test piping or hose shall be braced, sand bagged, and anchored to prevent movement, separation, and whipping. Chain or cable shall be used to secure the hose connection to the test manifold in the event the connections rupture or separate.

4.9. At no time shall screw fittings be tightened while pressurized. Pressure must be bled off prior to tightening.

4.10. If a leak occurs at a flange while pressurized, pressure shall be reduced to the last pressure that held for 15 minutes before tightening.

4.11. The Company Representative should conduct inspections of all temporary welds (subject to test pressure) using Company approved radiographic Contractor unless additional safety measures are implemented.

5. Initial Testing Procedure

5.1. If actual survey elevations do not match initial test plan, test pressures shall be adjusted. The test pressure shall not drop below minimum test pressure nor exceed the maximum test pressure specified on the construction drawings. The maximum test pressure shall not exceed 100% SMYS or 1.5 times the MAOP/MOP of any fitting or valve due to elevation changes unless approved by the Project Engineer.

5.2. Before the start of test operations, the Project Engineer shall review and approve the test plans utilizing some or all of the following information:

- Names of Contractor personnel conducting the test;
- Diagram indicating the lengths, elevations, and location of the test segments;
- Isolation methods for test segment;
- Blinds to install and valves to remove;
- Identification and specification of the weakest link in the test section;
- Testing timetable;
- Specific equipment locations;
- Cleaning plans;
- Water sources and analysis;
- Fill points;
- Temporary fill line locations;
- Discharge points;
- Fill and discharge rates;
- Test points;
- Filtration equipment;
- Disposal plan;
- Dispersion equipment;
- Recording charts;
- Reporting forms;
- Safety precautions and procedures; and
- Other equipment to be used for test.

5.3. Paddle flanges/skillets can be used if they are stamped with specifications/pressure ratings. Before using blank plates, Contractor shall perform and provide engineering calculations to prove compatibility of plate with test to be performed.

5.4. A pressure recorder shall record continuously during the test and cover a minimum range of 24 hours. The range of the pressure recorder shall be compatible with the test pressure with 20 psig increments.

5.5. A temperature recorder shall record continuously during the test and shall be compatible with the test and capable of measuring temperatures experienced during hydrostatic testing with one (1) degree increments.

5.6. Hydrostatic test water shall be discharged in accordance with applicable permits.

5.7. Staging and manifold areas for filling pipeline (with water) should be located a minimum of 50 feet from water's edge. If topographic conditions allow, such areas shall also be located 10 feet beyond the high bank to prevent runoff toward the water body.

5.8. Construction equipment refueling shall be conducted at a minimum distance of 100 feet from any water body unless spill containment countermeasures are in place.

5.9. Contractor shall install temporary sediment filter devices adjacent to all streams that may encounter runoff.

5.10. Upon completion of pipe lowering and backfilling operations and prior to filling the pipeline for a hydrostatic test, each section of the pipe to be tested shall be cleaned if required.

5.10.1. Contractor shall clean pipeline by running Company approved cleaning pigs propelled by compressed air or inert gas. Pigs shall be run completely through the pipeline test section. Additional cleaning pig runs shall be repeated as required until cleanliness of the test section is approved by the Company Representative, who will be present for the first and last brush pig run to compare their respective conditions and approve the cleanliness of the line.

5.10.2. If a cleaning pig becomes lodged in the line, pressure shall not be increased beyond 50 psig unless higher pressures are approved by the Company Representative. If the presence of water is determined to be the cause of stoppage, the Company Representative may authorize higher pressures to facilitate water movement. In such cases, the Company Representative may require pressure to be released and a dewatering line installed at the downstream receiver, as required by permit. When cleaning pigs cannot be dislodged, Contractor shall:

- Locate lodged pig(s) within the pipeline;
- Obtain Company Representative approval to remove lodged pig(s);
- Cut out affected section of pipeline;
- Rejoin/repair cut out section of pipeline; and
- Nondestructively test repair welds.

5.11. Upon completion of the cleaning operation, the temporary launcher and receiver for pigging shall be removed (if not permanent). Pipeline section ends shall be sealed by installing Company approved hydrostatic test headers or Company approved caps supported and/or braced to ensure personnel safety.

5.12. Pipeline test section shall be sealed to prevent dust, water, or foreign substances from entering and to preserve internal pipeline cleanliness until filling and pressure testing operations commence. Contractor shall tie-in cleaned pipeline sections as required to complete test sections and shall exercise care in tie-in operations to maintain internal pipeline cleanliness.

6. Filling the Pipeline

6.1. After final pipe positioning, Contractor shall fill the pipeline with water. Pipe ends shall not be restrained during filling. Before filling a test section with water, Contractor shall make a final check to verify:

- If test pressure exceeds set pressure, relief valves are removed and plugged prior to test process;
- All valves are in the open position;
- Valves have been greased (indicated by Operations tag) and stroked and packing has been tightened. If any of the aforementioned has not been completed, the Company Representative should be notified immediately;
- All pipe and bolt connections are tight;
- Test manifolds are fabricated and installed;

- Pumps and compressors are in good working condition;
- Hoses are in good mechanical condition and properly rated;
- Instruments are ready for use (proper charts installed, ink pens filled, clocks wound, correct calibration, etc.);
- Calibration time frame does not exceed 12 months on the calibration certificate unless otherwise specified in the Scope of Work; and
- Pigs are installed.

6.2. Contractor shall monitor each Company required pressure recorder along with ambient water temperatures during fill operation. These records shall be delivered to the Company Representative after completion of the pressure test. See Figure 1190.2 and Figure 1190.3 for temperature probe configurations above and below ground.

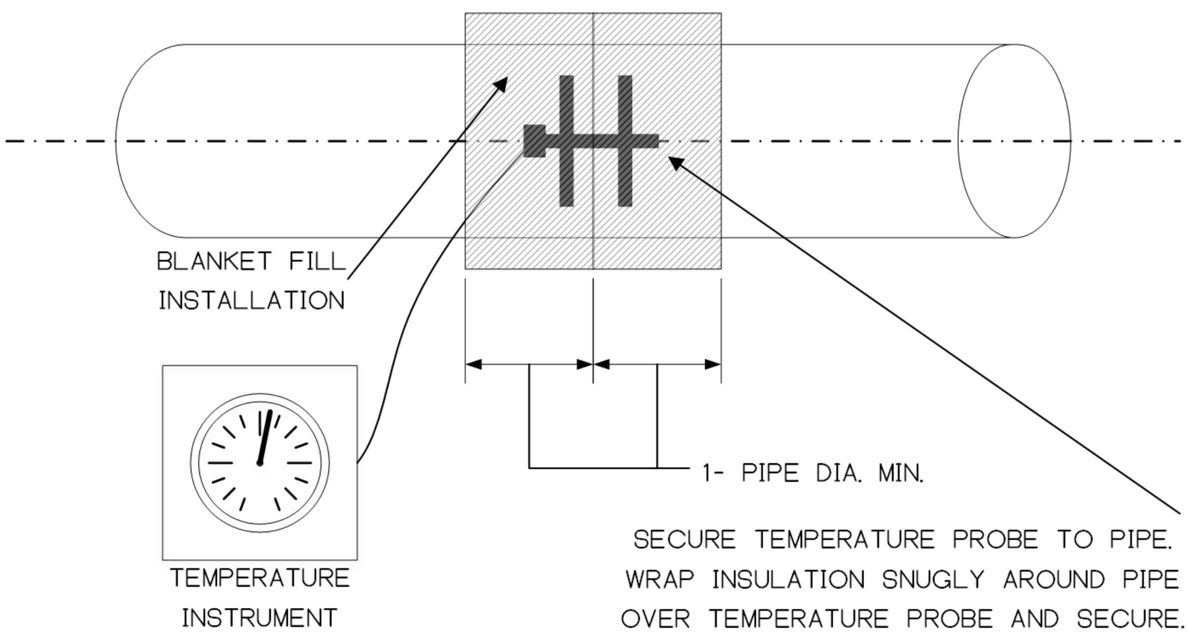


Figure 1190.2. Above Ground Temperature Probe Placement and Insulation

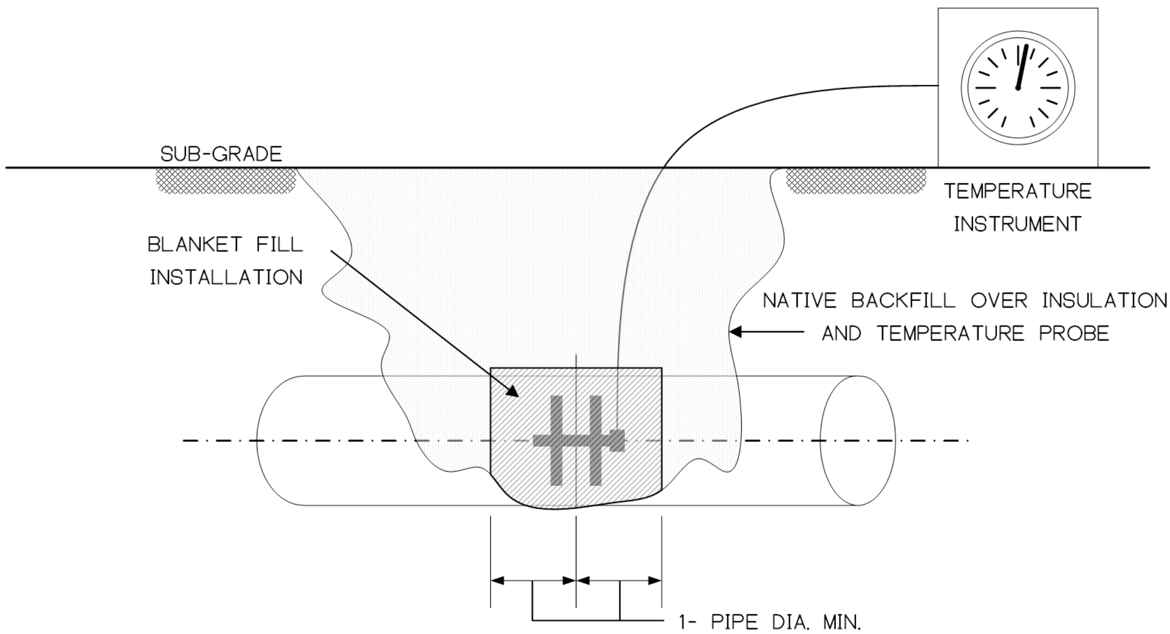


Figure 1190.3. Subgrade Temperature Probe Placement and Insulation

6.3. All mainline valves within the fill section must be open for fill pig passage, after which valves shall be closed halfway to fill the body cavity.

6.4. Contractor shall install a connection from the pipe test section to the body bleed valves supplied in the fully open position (no gearing) to equalize pressure across the valve seat.

6.5. Contractor shall insert fill pig into test head as appropriate for field conditions. The travel rate of fill pigs shall be controlled:

- To prevent acceleration during filling of downhill test section portions; and
- To ensure the water column in front of or behind the fill pig is not broken during filling operations.

6.6. The fill pig travel rate shall be controlled by maintaining air backpressure on the fill pig (based upon test section elevation profile) to prevent breaking the fill water column (by venting air in test section as fill pig progresses). Contractor is responsible for controlling fill pig velocity and ensuring water fill. Contractor shall supply approved pigs and place in temporary launchers and/or test headers as directed by the Company Representative.

6.7. Fill pumps shall be set in a catch pan (sized to contain all leaking lubricants or fuel and prevent them from entering the water source). When a natural water source is used, suction inlet shall be screened and use of a frac tank should be considered. Enclosure shall be placed at a depth that prevents air from being drawn in with the water. Enclosure may require a rock-lined sump to prevent intrusion of sediment. Disturbance of the stream channel may require a permit.

6.8. During pipeline water filling, Contractor shall use fill pumps capable of injecting water into the pipeline at an acceptable fill rate. Contractor should measure water volumes added to or removed from the pipeline.

6.9. Contractor shall increase pressure in the pipeline to maximum fill pump capability. After completion of the filling operation and prior to commencing the test, pipeline water temperature and water turbulence shall be allowed to stabilize. Contractor shall check the pressure on each test section end and compare with calculated pressures to confirm the specified test pressure for the section.

6.10. The following general steps should be followed unless otherwise specified by the Company Representative:

- Ensure signs "Hydrotest in Progress" are placed as directed by Company Representative;
- Turn valves to half open position;
- Confirm that the regulator is set on correct starting pressure (e.g., 100 psig);
- Begin pressuring up line and log time for each pressure increment and any leaks discovered and remedied; and
- Pressure up at maximum of 500 psig increments and hold for 15 minutes to test for leaks after each increase. If a pressure test is less than 500 psig hold at 50% of max.

7. Testing the Pipeline

7.1. After completion of the filling operation, Contractor shall install blind flanges and bull plugs on all fill connections not in use (for pressure gauge, deadweight gauge, pressure chart recorder, or pump connections).

7.2. During the test Contractor shall maintain pressure between the minimum and maximum allowable test pressures as indicated in Liquid Pipeline Facilities Pipeline Pressure and Test Report.

7.3. Personnel conducting the test should maintain continuous surveillance over the operation and ensure that it is carefully controlled. Test equipment and personnel shall be positioned to minimize hazards. Test equipment should be placed 25 feet away from the test.

7.4. Contractor shall perform and record the pressure test.

7.4.1. Contractor shall maintain communications with the Company Representative during the test at Company designated locations (e.g., road crossings, valve sites, etc.).

7.4.2. Contractor shall not test through equipment or against a fully opened or closed valve unless pre-approved by the Company Representative.

7.4.3. Contractor shall make every effort to keep non-essential personnel off the Right-of-Way (ROW) and away from the test area. Contractor shall check all above grade pipe and fittings for leaks.

7.4.4. If requested by Company, Contractor shall produce a pressure-volume plot where the test pressure will result in a hoop stress exceeding 90% of SMYS at any point along the pipeline. For practical reasons, yield plots shall not be required on any test section less than 1,000 feet in length. The pressure-volume plot shall be initiated at 85% of SMYS and consist of a graph showing water volume (gallons) added versus pressure (at 10 psig intervals or at intervals sufficient to show any deviation). A stroke counter must be used when a pressure-volume plot is required. The graph shall be plotted by hand. A constant pumping rate shall be maintained during pressurization. Sufficient water shall be provided to complete the plot without stopping until full test pressure is reached.

7.4.5. Contractor shall record deadweight readings at a minimum of every 15 minutes during the One (1) Hour No Pressure Loss Hold and 30 minutes otherwise.

7.4.6. When the test pressure is reached, pumping should be stopped, and all valves and connections to the line should be inspected for leakage. After inspecting for leakage, verify that the specified test pressure is being maintained and that temperatures have stabilized. After the verification procedure is completed, the injection pump should be disconnected from the test section.

7.4.7. At some point during the hydrostatic test, a One (1) Hour No Pressure Loss Hold must be achieved. The following shall occur during the hold:

- Contractor shall not re-pressure the test;
- Pressure may be bled off so that maximum pressure (adjusted for elevation) is not exceeded. If pressure drops below the minimum during this hour, Contractor shall repair leaks and begin a new One (1) Hour No Pressure Loss Hold until pressure is held between the specified limits;

- The mainline test may be accepted without achieving the One (1) Hour No Pressure Loss Hold if the pressure loss is due solely to fluctuations in the test medium temperature. Acceptance of a pressure test which has not satisfied the One (1) Hour No Pressure Loss Hold requirement shall require approval from the Project Engineer or designee, as appropriate. Written approval must be included in test documentation. All appropriate calculations shall be included in the test documentation to support such acceptance; and

- For pressure tests of fabrications and short sections of pipe where all piping is exposed, the test may be accepted without accomplishing One (1) Hour No Pressure Loss Hold if the Company Representative can visually determine that there are no leaks present. The Company Representative must note on the test report that the facilities were visually inspected and no leaks were present. Visual acceptance during hydrostatic tests requires that the outside surface of the test section be dry (i.e., it is not raining or the test section is protected from the elements).

7.4.8. Pipe connections should be periodically checked for leaks.

7.4.9. Pressure and temperature recording devices should be set to local time and should be connected throughout the final pressurization and testing period. Any weather changes, such as rain or clouds that could affect the pressure and temperature recording charts, should also be noted on Liquid Pipeline Facilities Pipeline Pressure and Test Report. The pressure drop should not exceed two (2) psig per hour for the duration of the test including the One (1) Hour No Pressure Loss Hold unless pressure drop is for reasons other than a leak. If necessary, the test period shall be extended until this requirement is satisfied.

7.4.10. For testing in-place natural gas pipelines containing unidentified pipe, yield is determined using the double stroke method per Paragraph 3.22.

7.5. Contractor shall provide all labor and equipment required to locate and repair any leak or rupture, as determined by the Company Representative.

7.6. If a failure occurs in a pipe seam, the entire joint shall be removed from the pipeline. For other leaks, Contractor shall mark and remove pipe as a cylinder containing the defective area. Pipe, fittings, or valves that fail and are replaced should be noted on Liquid Pipeline Facilities Pipeline Pressure and Test Report with their pipeline station location and the pressure at which they failed. The Company Representative shall determine actual pipe length(s) to be removed. Removed piece(s) of pipe shall be marked for orientation (with respect to the pipeline position) and with the alignment sheet station number of the defect location. Contractor shall not cut on or damage the failed pipe edge during removal, transit, or unloading at Company's designated storage location. All cut-out sections of pipe shall be provided to the Company Representative.

7.7. Contractor shall be responsible for delays, leaks, or failures caused by, but not limited to, any of the following:

- Girth welds and flanged connections installed Contractor;
- Construction damage (such as dents and gouges in piping) caused by Contractor;
- Test head malfunction;
- Unavailability or malfunction of Contractor supplied materials and equipment;
- Labor problems;
- Faulty installation of Company supplied equipment;
- Performance of any Contractor supplied pigs;
- Freezing water in the test section, fill lines, or instrument lines;
- Excessive or inadequate test pressures, including those due to temperature changes;
- Malfunctioning valves or other pipeline components (Company supplied or otherwise) where Contractor could have prevented said malfunctions through timely action (e.g., tightening bolts or other fasteners, replacing gaskets or rubbers, inserting sealant, etc.); and
- Contractor's failure to comply with any specification or condition contained in the Scope of Work, drawings, permits, or other relevant construction documents.

7.8. Contractor shall provide a complete record of the test, and any failures that occur during the test shall be described in this record. The record shall indicate the exact location of each failure, describe the type of failure and its cause, and describe the method of repair. Test records shall be signed by the responsible parties and retained by Company for the life of the pipeline or until new test records supersede them. The following data shall be recorded using Liquid Pipeline Facilities Pipeline Pressure and Test Report:

- Continuous pressure versus time record with appropriate information listed;
- Continuous temperature versus time record with appropriate information listed;
- Test instrument calibration data;
- Hydrostatic test record and certification qualification calculation, pressure and temperature log, record of failures, and profile of the pipeline that shows the elevation and test sites over the entire length of the test section if elevation differences in the test section exceed 100 feet;
- Pressure Test Failure Report, when applicable; and
- Leaks during leak test.

7.9. Contractor shall also submit the following completed forms to the Company Representative at the completion of the pressure test:

- Pressure-volume plots (if applicable);
- Calibration certificates;
- Field Pressure and Test Report;
- Test Section Data and Log; and
- Test section plan and profile sketch (if available).

8. Dewatering the Pipeline

8.1. As soon as possible after test acceptance by the Company Representative, Contractor shall reduce pipeline pressure at a limited rate to avoid development of vibrations. Contractor shall exercise extreme caution throughout the depressuring process. Valves shall be opened and closed slowly to protect assembly from shock loading.

8.2. Prior to beginning any dewatering activities, Contractor shall ensure that all mainline valves have been returned to the fully open position and shall purge valve bodies.

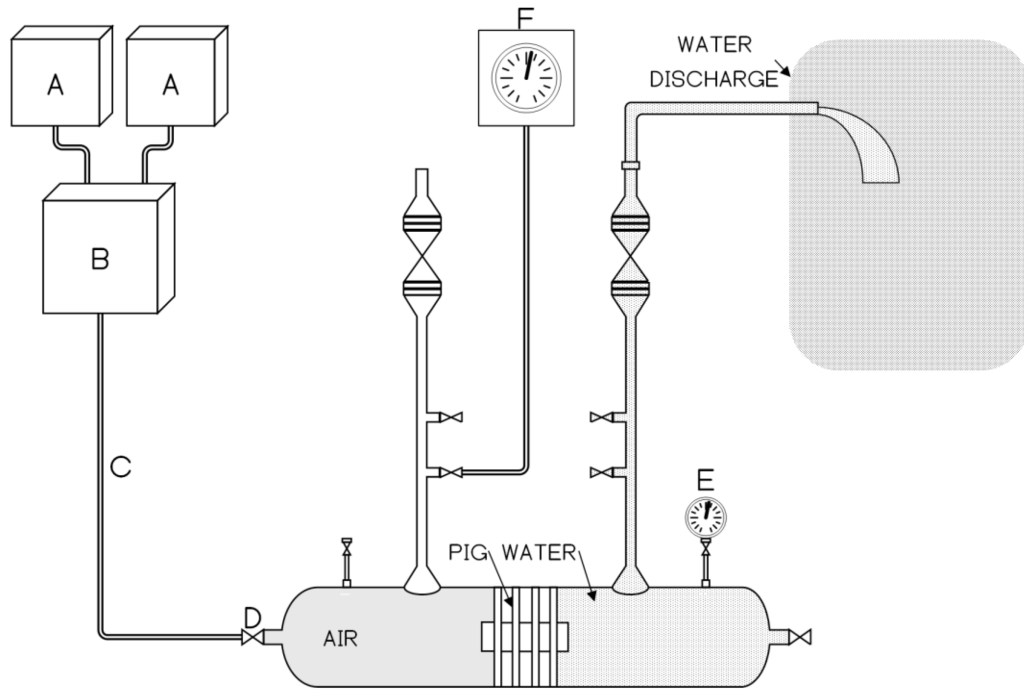
8.3. Once test section is prepared for dewatering, a squeegee or polyethylene pig shall be run to dewater the pipeline. Pigs shall be run as many times as necessary in the same direction to remove free water as required by the Company Representative. Test water shall be discharged in accordance with applicable permits.

8.4. Complicated piping segments such as meter station piping that are difficult to swab and blow through will require proper planning coordination with the Company Representative. All test sections shall be designed to allow all water to be drained at the low point(s) if they cannot be emptied using pigs. Test sections can be rotated or moved after testing to facilitate drainage if they can be properly supported to prevent excessive stress on the test section.

8.5. If the adjacent test section is to be filled from or through a prior test section, a bleed down shall be performed into the section to be filled. Contractor shall provide air pressure behind a pig to displace water from the test section. Extreme caution shall be used to prevent air lock in the test section to be dewatered.

8.6. Contractor is responsible for disposing of test water in conformance with governing permits and Company requirements.

8.7. Dewatering lines shall be securely supported and tied down at discharge end to prevent uncontrolled movement during dewatering. See Figure 1190.4 for a typical dewatering arrangement.



A- PRIMARY AIR COMP. 125 PSI
B- TWO STAGE BOOSTER COMP. 125-900 PSI
C- 3" HIGH PRESS. FLEX HOSE OR 3" PIPE W/ SWIVEL JTS.
D- 2" FULL OPEN PLUG VALVE
E- PRESSURE GAUGE
F- PRESSURE RECORDER

Figure 1190.4. Typical Dewatering Arrangement

8.8. Discharge lines shall be sufficient in strength and shall be securely supported and constrained at the discharge end to prevent shifting during the dewatering operation.

8.9. Contractor shall control system backpressure and discharge volume of water. Discharge rates shall be followed as specified in applicable permits or as directed by the Company Representative.

8.10. Contractor shall repair ROW and/or adjacent property damage caused by test section dewatering as directed by the Company Representative.

8.11. Company may request that methanol or rust inhibitors be put into the line between displacement pigs.

8.12. The drying process shall continue by pigging and/or purging with dry air until the complete pipeline, including valves and fittings, is clean and dry to a -40°F dew point or drier unless otherwise specified in the Scope of Work or other relevant construction documents. For gathering pipelines, it is permissible to use foam pigs that do not exceed 1/4 inch penetration and/or one (1) pound weight differential unless directed otherwise by the Company Representative.

8.13. When required, the dew point shall be monitored at the pipeline receiver by a digital hygrometer provided by Contractor. The digital hygrometer shall be approved by Company and shall have calibration certification within the past 12 months. Company, at its option, may check the dew point with Company supplied instrument.

8.14. All reliefs that were removed should be properly installed.

Pressure Testing with Water

MARKWEST Energy Partners, L.P.

Section No.: MW-PC-1190

Subject: Construction Standards **Date Issued:** 9/4/2015 **Date Revised:** 07/13/2017 **Date Printed:** 8/23/2021

Pipeline Construction Manual **Revision 1.4**

Appendix A – Onshore Gas Pipeline Pressure and Leak Test Requirements

49 CFR 192 and ASME B31.8

Condition	Class	Test Requirements	Company Standard
• Steel Pipe with MAOP Hoop Stress ≥30% SMYS • 49 CFR §192.505 and §192.619 • ASME B31.8 §841.32	• 1 (5)	• Minimum: 1.1x MAOP (Division 1) or 1.25x MAOP (Division 2) • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2x design pressure or valve/flange maximum pressure limitation (1)(2) • Time: 8 hours, minimum	• 1.5x design pressure (unless written approval is obtained from Engineering and Operations Management and at a minimum the code is met) • Time: 8 hours at minimum • Test Medium: Water (3)(4)
	• 2 (5)	• Minimum: 1.25x MAOP • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2x design pressure or valve/flange maximum pressure limitation (1)(2) • Time: 8 hours, minimum	
	• 3 and 4	• Minimum: 1.5x MAOP • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2x design pressure or valve/flange maximum pressure limitation (1)(2) • Time: 8 hours, minimum	
• Fabricated Units and Short Sections of Steel Pipe with MAOP Hoop Stress • ≥30% SMYS for which a post-installation test is impractical • 49 CFR §192.505(e)	• 1 (5)	• Minimum: 1.1x MAOP • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2x design pressure or valve/flange maximum pressure limitation (1)(2) • Time: 4 hours, minimum	• 1.5x design pressure (unless written approval is obtained from Engineering and Operations Management and at a minimum the code is met) • Time: 4 hours, minimum • Test Medium: Water (3)(4)

Pressure Testing with Water

Section No.: MW-PC-1190

Subject: Construction Standards **Date Issued:** 9/4/2015 **Date Revised:** 07/13/2017 **Date Printed:** 8/23/2021
Pipeline Construction Manual **Revision 1.4**

Condition	Class	Test Requirements	Company Standard
	• 2 (5)	• Minimum: 1.25x MAOP • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2x design pressure or valve/flange maximum pressure limitation (1)(2) • Time: 4 hours, minimum	
	• 3 and 4 (7)	• Minimum: 1.5x MAOP • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2 x design pressure or valve/flange maximum pressure limitation (1)(2) • Time: 4 hours, minimum	
• Steel Pipe with MAOP Hoop Stress • <30% SMYS and ≥100 psig (6) • 49 CFR §192.507 and §192.619 • ASME B31.8 §841.33 and §841.34	• 1 (5)	• Strength Test: • Minimum: 1.1 x MAOP • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2 x design pressure or valve/flange maximum pressure limitation (1)(2) • Time: 1 hour, minimum	• 1.5 x design pressure (unless written approval is obtained from Engineering and Operations Management and at a minimum the code is met) • 8 hours, minimum • Test Medium: Water (3)(4)
	• 2 (5)	• Strength Test: • Minimum: 1.25 x MAOP • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2 x design pressure or valve/flange maximum pressure limitation (1)(2) • Time: 1 hour, minimum	

Pressure Testing with Water

Section No.: MW-PC-1190

Subject: Construction Standards **Date Issued:** 9/4/2015 **Date Revised:** 07/13/2017 **Date Printed:** 8/23/2021
Pipeline Construction Manual **Revision 1.4**

Condition	Class	Test Requirements	Company Standard
	• 3 and 4 (7)	• Strength Test: • Minimum: 1.5 x MAOP • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2 x design pressure or valve/flange maximum pressure limitation (1)(2) • Time: 1 hour, minimum	
• Steel Pipe with MAOP <100 psig • 49 CFR, §192.509 • ASME B31.8 §841.35	• ALL	Leak Test: • Minimum: 10 psig	• 1.5 x design pressure (unless written approval is obtained from Engineering and Operations Management and at a minimum the code is met) • 8 hours, minimum • Test Medium: Water (3)(4)
• Pretested Pipe • Undetermined design pressure • Less than 10 3/4 inch O.D. for specific locations with components rated greater than ANSI 600# • ASME B31.8	• ALL	• Minimum: The lower of 1.5 x design pressure, 93% SMYS of the lowest strength pipe or 2,175 psig (2,175 psig based on ANSI 600# system components) • Maximum: The lower of 100% SMYS, 2 x design pressure or 2,225 psig (2,225 psig based on ANSI 600# components) • Time: 4 hours, minimum	• 1.5 x design pressure • 8 hours, minimum • Test Medium: Water (3)(4)

Pressure Testing with Water

Section No.: MW-PC-1190

Subject: Construction Standards **Date Issued:** 9/4/2015 **Date Revised:** 07/13/2017 **Date Printed:** 8/23/2021
Pipeline Construction Manual **Revision 1.4**

1.	If minimum test pressure exceeds 100% SMYS of lowest strength pipe/component, test pressure shall be reduced to 93% SMYS of lowest strength component. Refer to Appendix C, for maximum test pressure of various classes of valves and flanged fittings.
2.	On existing pipelines, the maximum test pressure may exceed 100% of the pipe SMYS and shall be shown on the drawings.
3.	The code requires: If any building lies within 300 feet of subject pipeline, a hydrostatic test must be completed at test pressure equal to 1.25xMAOP. However, if building(s) evacuated when hoop stress >50% SMYS, air or inert gas may be used as test medium.
4.	Test pressures for above ground facilities shall use a 1.5 pressure test factor.
5.	For fabricated units and short sections of pipe to be installed in jurisdictional intrastate pipelines in Texas, pre-tested sections shall be limited to 100 feet unless pre-tested for eight hours.
6.	Refer to Appendix C, for maximum test pressure of various classes of valves and flanged fittings. For test pressures for test mediums other than water, refer to MW-PC-1191 Pressure Testing with Other Media.
7.	On existing facilities, the maximum test pressure may exceed 100% of the pipe SMYS and shall be shown on the drawings.

Appendix B – Onshore Liquid Pipeline Pressure and Leak Test Requirements

49 CFR 195 and ASME B31.4

Condition	Test Requirement	Company Standard
• MOP produce a hoop stress • > 20% SMYS of the lowest strength pipe and is visually inspected during strength test • 49 CFR §195.304 • ASME B31.4 §437.4.1	• Minimum: 1.25x MOP (Pressure Test) • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2x design pressure or valve/flange maximum pressure limitation (2)(3) • Time: 4 hours, minimum	• 1.25x MOP • 4 hours • Test medium: Water
• MOP produce a hoop stress • > 20% SMYS of the lowest strength pipe and is NOT visually inspected during strength test • 49 CFR §195.304 • ASME B31.4 §437.4.1	• Minimum: 1.25 x MOP (Pressure Test) • 1.1 x MOP (Leak Test) • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2x design pressure or valve/flange maximum pressure limitation (2)(3) • Time: 4 hours, minimum, for strength test PLUS additional 4 hours for leak test	• 1.25 x MOP • 8 hours • Test medium: Water
• MOP produce a hoop stress • ≤ 20% SMYS of the lowest strength pipe • ASME B31.4 §437.4.3	• Minimum: 1.25 x MOP (Leak Test) • Maximum: Lower of 100% SMYS of the lowest strength pipe, 2 x design pressure or valve/flange maximum pressure limitation (2)(3) • Time: 1 hour, minimum	• 1.25 x MOP • 4 hours • Test medium: Water

Pressure Testing with Water

Section No.: MW-PC-1190

Subject: Construction Standards **Date Issued:** 9/4/2015 **Date Revised:** 07/13/2017 **Date Printed:** 8/23/2021
Pipeline Construction Manual **Revision 1.4**

1.	If minimum test pressure exceeds 100% SMYS of lowest strength pipe/component, test pressure shall be reduced to 93% SMYS of lowest strength component. Refer to Appendix C, for maximum test pressure of various classes of valves and flanged fittings.
2.	On existing pipelines, the maximum test pressure may exceed 100% of the pipe SMYS and shall be shown on the drawings.
3.	The code requires: If any building lies within 300 feet of subject pipeline, a hydrostatic test must be completed at test pressure equal to 1.25xMAOP. However, if building(s) evacuated when hoop stress >50% SMYS, air or inert gas may be used as test medium.
4.	Test pressures for above ground facilities shall use a 1.5 pressure test factor.
5.	For fabricated units and short sections of pipe to be installed in jurisdictional intrastate pipelines in Texas, pre-tested sections shall be limited to 100 feet unless pre-tested for eight hours.
6.	Refer to Appendix C, for maximum test pressure of various classes of valves and flanged fittings. For test pressures for test mediums other than water, refer to MW-PC-1191 Pressure Testing with Other Media.
7.	On existing facilities, the maximum test pressure may exceed 100% of the pipe SMYS and shall be shown on the drawings.

Appendix C – Test Pressures for Flanged Fittings and Valves

Valve Class Or Class Designation	Working Pressure (1)	Shell Test Pressure		Seat Test Pressure	
		Minimum	Maximum	Valve ≥ 8"	Valve < 8"
150	285	425	475	475	300
300	740	1100	1100	1150	800
400	990	1450	1450	1500	1060
600	1480	2175	2175	2225	1600
900	2220	3250	3250	3300	2400
1500	3705	5400	5400	5450	4000
2500	6170	9000	9000	9050	6600

1. Maximum working pressure ratings for flanged-end, gate, plug, ball and check valves at 100°F. Higher temperatures will derate this number.
2. Pressures shown are maximum seat test pressures and shall not be exceeded. Maintain the seat test pressure for each seat for thirty minutes. Remove the body bleed as a method to determine whether the seat is good. The pressure should hold with minimum pressure drop. If not, the valve should be repaired or junked.
3. Pressures shown are maximum shell test and shall not be exceeded. The valve shall be partially open (1/4 open) during the shell test. Maintain the shell test pressure at or above the minimum test pressure for four hours.

Appendix D – Gas Pipeline Facilities Pipeline Pressure and Test Report

MARKWEST Energy Partners, L.P.

PIPELINE PRESSURE & TEST REPORT DELIVERABLES

AFE					
Project:					
Segment:					
Contractor:					

	Identified Weakest Link	Main Lie Material #1	Main Line Material #2	Main Line Material #3	Main Line Material #4
Class Location:					
Pipe Size:					
Pipe Grades:					
Pipe Wall Thickness:					
Start Station and Elevation:					
End Station and Elevation:					
High Station and Elevation:					
Low Station and Elevation:					
Test Staton and Elevation:					
Low Flange Station and Elevation:					
ANSI Flange Rating:					
Station # and Elevation where class changes:					

	Above Ground Material #1	Above Ground Material #2	Above Ground Material #3	Above Ground Material #4
Class Location:				
Pipe Size:				
Pipe Grades:				
Pipe Wall Thickness:				
Start Station and Elevation:				
End Station and Elevation:				
High Station and Elevation:				
Low Station and Elevation:				
Test Station and Elevation:				
Low Flange Station and Elevation:				
ANSI Flange Rating:				
Station # and Elevation where class changes:				

NOTES:

Survey: Date: / /

Inspector: Date: / /

APPENDIX D
CATHODIC PROTECTION STANDARDS

	Engineering Standard	ENG-STD-0004	
	Cathodic Protection for Buried or Submerged Metallic Structures	Page 1 of 11	
		DATE: 4/1/2021	Rev: 0

Contents

List of Tables

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for the design and installation of cathodic protection systems to protect buried or submerged pipelines and structures from external corrosion to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life for the asset.
- Standardization of work procedures, design, materials, installation and inspection requirements as they pertain to the mitigation of external corrosion.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- OPS-STD-0020 Aboveground Cathodic Protection Surveys
- OPS-STD-0023 Electrical Isolation Monitoring and Maintenance
- OPS-STD-0025 AC Interference Monitoring and Mitigation

2.2 Industry Codes and Standards

- NACE SP0177-2007 Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems
- NFPA 70-2017 National Electric Code

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Anode	An electrode that is characterized by electron loss.
Cathodic Protection	A technique to control corrosion of a metal surface by making it the cathode in an electrochemical cell.
Contractor	Company or business that agrees to furnish materials or perform specified services at a specified price and/or rate to MPLX.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.

Term	Description
Current Density	The current per unit area.
Electrical Isolation	The condition of being substantially electrically separated from other metallic structures and the environment.
Electrode Potential	The potential of an electrode as measured against a reference electrode.
Electrolyte	A medium through which electrically charged particles (ions) may travel. Typically soil, water, or product in this application.
Foreign Structure	Any structure that is not part of the subject structure.
Galvanic Anode	Typically, a prepackaged assembly consisting of an active metal (Mg, Zn, etc.) in a moisture retaining backfill. Generally, any metal which is more electrochemically active in a multi-metal system.
Galvanic Series	A list of metals and alloys arranged according to their relative potentials in a given environment.
Holiday	A discontinuity of coating that exposes the metal surface to the environment.
Impressed Current	Direct current supplied by a power source external to the electrode system.
Interference Bond	A metallic connection designed to control electrical current interchange between metallic systems.
Isolation	See Electrical Isolation.
Manufacturer	Direct or indirect producer of materials, fabricated components, or subassemblies.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
Polarization	The deviation from the open circuit potential of an electrode resulting from the migration of ions at the structure to electrolyte interface, caused by the passage of current.
Reference Electrode	A device whose open circuit potential is constant under similar conditions of measurement.
Sacrificial Protection	Reduction or prevention of corrosion of a metal in an electrolyte by galvanically coupling it to a more anodic metal.
Shared Electrolyte	Electrolyte in contact with both the electrode and the structure.
Stray Current	Current flowing through paths other than the intended circuit.
Structure-to-Electrolyte Voltage (Also Structure-to-Soil Potential or Pipe-to-Soil Potential)	The voltage difference between a metallic structure and reference electrode in contact with a shared electrolyte.
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.

4.0 DETERMINATION OF NEED FOR CATHODIC PROTECTION

4.1 Each buried or submerged pipeline shall be protected from external corrosion with a cathodic protection system(s), unless otherwise approved by the Regional Corrosion Control Team Lead or Engineer (see Section 4.1.1). The cathodic protection system(s) shall be in operation not later than one year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable.

5.0 OBJECTIVES OF CATHODIC PROTECTION SYSTEM DESIGN

5.1 Effective cathodic protection system design will achieve the following objectives:

5.1.1 Provide sufficient current to the structure to be protected and distribute this current so that the selected criteria for cathodic protection are efficiently attained.

5.1.2 Provide a design life of the anode system commensurate with the required life of the protected structure, or provide for periodic rehabilitation of the anode system.

5.1.3 Provide adequate allowance for anticipated changes in current requirements with time.

5.1.4 Place anodes where the possibility of disturbance or damage is minimal.

6.0 DESIGN OF CATHODIC PROTECTION SYSTEMS

6.1 General

6.1.1 The purpose of this section is to recommend procedures for designing cathodic protection systems to provide effective corrosion control by satisfying one or more of the criteria listed in OPS-STD-0020, to provide maximum reliability over the intended operating life of the systems. In the design of a cathodic protection system, the following items shall be evaluated and designed accordingly:

1. Recognition of hazardous conditions prevailing at the proposed installation site(s), including induced alternating-current.
2. Specification of materials and installations that minimize interference current, earth potential gradients, or detrimental effects on neighboring, submerged or foreign metallic structures.
3. Selection and specification of materials and installation practices which shall assure dependable operation throughout the intended operating life of the cathodic protection system (typically 20 years).
4. Direction of cooperative investigations to determine a mutually satisfactory solution(s) of interference problems (See Section 8.0 of this Standard).
5. The effects of polarization on coatings and metallurgical compositions susceptible to hydrogen overvoltage or embrittlement.
6. The presence of amphoteric metals.

6.1.2 Galvanic anodes can be of materials such as alloys of magnesium, zinc, or aluminum. These are installed in the soil or water, either bare or packaged in special backfill. The anodes are connected to the pipe, either singly or in groups. Galvanic anodes are limited in current output by the pipe-to-anode driving voltage and the earth resistivity. Cathodic protection of large bare or poorly coated piping may not be attainable by using galvanic anodes.

6.1.3 Impressed current anodes may be constructed of mixed-metal oxide (MMO), high silicon cast iron, noble metals, conductive composites, among other materials. These anodes are installed in contact with the electrolyte either bare or in contact with resistance-reducing backfill. These are connected to the positive side of a direct current (DC) current source. The structure or pipeline to be protected is connected to the negative side of the DC source.

6.2 Design Factors for Cathodic Protection Systems

6.2.1 Consideration shall be given to the electrical properties of non-welded pipe joints. Where it is the objective to ensure electrical continuity, this shall be achieved either by using fittings manufactured for this purpose or by bonding the mechanical joints with electrical connections.

6.2.2 The pipeline shall be evaluated to determine where electrical contact with support structures would adversely affect cathodic protection. Example support structures include pipe stanchions, bridge structures, tunnel enclosures, piling, or reinforcing steel in concrete.

6.2.3 Insulating devices consisting of flange assemblies, prefabricated joints, unions or couplings shall be installed where electrical isolation of portions of the system are required to facilitate the application of corrosion control. The insulating device shall be constructed of a material properly rated for temperature and pressure operating requirements, and also meet the minimum dielectric strength ratings in Table 2.

Table 2 Minimum Required Dielectric Strength of Insulating Components

Insulating Component	Minimum Required Dielectric Strength (Volts/Mil)
Insulating and Sealing Gasket	550
Full Length Bolt Insulating Sleeves	400
Insulating Washers	550

6.2.4 If an insulating device is installed in an area where a combustible atmosphere is reasonable to foresee, then precautions shall be taken to prevent arcing.

6.2.5 The need for lightning and fault current protection at insulating devices shall be evaluated per OPS-STD-0025.

6.3 Factors Determining Anode Current Output, Operating Life, and Efficiency

6.3.1 Various anode materials have different rates of deterioration when discharging a given current density from the anode surface in a specific environment. Therefore, for a given current output, the anode life shall depend on the anode material as well as the anode weight and the number of anodes in the cathodic protection system. Established anode performance data shall be used to calculate the probable deterioration rate.

6.3.2 Proper design of a galvanic anode system shall consider pipe-to-anode potential with resultant current output and, in special cases, anode lead wire resistance.

6.3.3 In the design of an extensive distributed anode impressed current system, the voltage and current attenuation along the anode connecting wire shall be evaluated. In such cases, the design objective is to optimize anode system length, anode spacing and size, and conductor size in order to achieve efficient corrosion control at the extremities of the protected structure.

6.3.4 Where it is anticipated that entrapment of gas actions could impair the ability of the impressed current groundbed to deliver the required current, the system design shall provide for venting the anodes.

6.4 Design Drawings and Specifications

6.4.1 Design records for cathodic protection system shall be retained for the life of the cathodic protection system, including the following where applicable:

1. Design calculations
2. Power source capacity, circuit breakers, panels, etc.
3. Number of anodes
4. Anode material and expected life
5. Anode installation details
6. Type, quantity, and location of stationary reference electrodes
7. Cost of system
8. Design drawings
9. Detailed layout of new test stations

6.4.2 As-Built drawings shall designate the overall layout of the piping to be protected and the location of significant items of structure hardware, corrosion control test stations, electrical bonds, electrical insulators, and known neighboring buried or submerged metallic structures.

6.4.3 Layout drawings shall be prepared for each impressed current cathodic protection installation, showing the details and location of the components of the cathodic protection system with respect to the protected structure(s) and to major physical landmarks.

6.4.4 The locations of galvanic anode installations shall be recorded on drawings or in tabular form, with appropriate notes as to anode type, weight, spacing, depth, and backfill.

6.4.5 Design specifications shall be prepared for all materials and installation practices that are to be incorporated in construction of the cathodic protection system.

6.5 Anode Ground Beds Installation Criteria

6.5.1 Deep Well Ground Beds

1. Drawings of the anode locations and lead wires shall be kept for the life of the ground bed to assist with surveys and excavations.
2. Seal the top of the well to prevent surface run off from entering the ground bed, if required by State Regulations.
3. Surface casings, when used, shall be externally sealed to prevent water entry, as required by State Regulations.
4. Vent pipe shall be installed from the bottom of the anode backfill material to the surface, terminating aboveground and designed to prevent entrance of surface waters.
5. Groundbeds shall be designed and installed in a manner to avoid intermixing of underground aquifers, per State Regulations.
6. All anode lead wire shall be appropriately sized for current carrying capacity and insulated.
7. Each anode shall have its own lead wire.

6.5.2 Horizontal Ground Beds

1. Drawings of the anode locations and lead wires shall be kept for the life of the ground bed to assist with surveys and excavations.
2. Size anode header cable so that all anodes receive sufficient current to meet their design output.
3. Location of parallel ground beds shall be clearly marked to prevent any excavation damage.
4. All anode lead wire shall be appropriately sized for current carrying capacity and insulated.

6.5.3 Distributed Ground Beds

1. Drawings of the anode locations and lead wires shall be kept for the life of the ground bed to assist with surveys and excavations.
2. Size anode header cable so that all anodes receive sufficient current to meet their design output.
3. Mark location of each anode on the surface with concrete or other monolithic marker to help prevent excavation damage.
4. All anode lead wire shall be appropriately sized for current carrying capacity and insulated.

6.5.4 Galvanic Ground Beds

1. The header cable shall be brought to a test point to permit monitoring, and periodic measurement of output current, for calculation of anode life.
2. The depth of burial and the location with respect to the structure to protect shall be specified.
3. For buried applications, zinc or magnesium anodes shall be used with the specified chemical backfill.

6.6 Anode Ground Bed Environmental Considerations

6.6.1 This section recommends design, construction, installation, and abandonment techniques for deep anode beds to address environmental considerations. To determine environmental considerations, the appropriate federal, state, or local natural resource, ground water management authority, or other governing entity shall be contacted.

6.6.2 Deep anode bed systems shall be installed in areas not subject to surface or subsurface contamination.

6.6.3 Design shall include the prevention of surface fluid runoff from entering the deep anode bed system. Surface casings, if used, shall be externally sealed. Sealing materials that may be used include concrete, grout, or bentonite-cement mixtures. Example grouts include:

1. Neat cement grout – A mixture consisting of 43 kg (one 94-lb bag) of Portland cement to 19 to 23 L (5.0 to 6.0 gal) of clean water.
2. Cement grout – A mixture consisting of 43 kg (one 94-lb bag) of Portland cement to an equal volume of sand (diameter of sand shall be no larger than 2 mm [0.08 in.]) to 19 to 23 L (5.0 to 6.0 gal) of clean water.
3. Bentonite clay grout – A mixture consisting of water and sodium montmorilonite (bentonite) clay containing high solids.

6.6.4 If casings are utilized in the deep anode bed system, a minimum space of 51 mm (2.0 in.) shall exist on all sides for sealing.

6.6.5 The surface portion of uncased deep anode bed systems shall be sealed if required to prevent entry of fluid runoff.

6.6.6 Vents shall be extended to a well-ventilated area above the high-water level.

6.6.7 Cross contamination of water between strata shall be avoided.

1. Sealing within the deep anode bed system shall be utilized to prevent intermixing of water between strata. If a casing is used, a seal around the outside of the casing shall be employed vent pipe shall be designed to avoid cross contamination. Dual vent pipes can be used to prevent compromise of the internal seal.

6.6.8 Deep anode bed materials that do not contaminate underground water supplies shall be used.

1. Accurate records of the material used and the data pertaining to its chemical analysis shall be maintained for the life of the asset.

6.6.9 A deep anode bed system that has been depleted or is no longer required shall have an abandonment procedure. The following procedures shall be considered minimum requirements.

1. All uncased holes, casings, and vent pipes shall be properly sealed.
2. All aboveground appurtenances shall be removed or secured to prevent tampering.

7.0 INSTALLATION OF CATHODIC PROTECTION SYSTEMS

7.1 General

7.1.1 The purpose of this section is to recommend procedures that shall result in the installation of cathodic protection systems that achieve protection of the structure when design considerations recommended in Section 7.0 of this Standard have been followed.

7.1.2 All construction work on cathodic protection systems shall be performed in accordance with construction drawings and specifications. The construction specifications shall be in accordance with Section 7.0 and Section 8.0 of this Standard.

7.2 Construction Supervision

7.2.1 Cathodic protection systems shall be installed, operated and maintained by or under the direction of an individual that is qualified to perform these tasks per Appendix E in OPS-STD-0017.

7.2.2 Any deviations shall be approved by the Regional Corrosion Control Team Lead or Engineer and shall be shown on as-built drawings.

7.3 Galvanic Anodes Inspection and Handling

7.3.1 Packaged anodes shall be inspected, and steps taken to assure that backfill material completely surrounds the anode. The individual container for the backfill material and anode shall be intact. If individually packaged anodes are supplied in waterproof containers, that container shall be removed before installation. Packaged anodes shall be kept dry during storage.

7.3.2 Lead wire shall be securely connected to the anode. Lead wire shall be inspected for assurance that it is not damaged.

7.3.3 Other galvanic anodes, such as unpacked “bracelet” type or ribbon, shall be inspected for assurance that dimensions conform to design specifications and that any damage during handling does not affect application. If a coating is used on bands and the inner side of "bracelet" anode segments, it shall be inspected and, if damaged, repaired before the anodes are installed.

7.4 Installing Galvanic Anodes

7.4.1 Galvanic anodes shall not be directly connected (i.e. welded) to the pipeline. Galvanic anodes shall always be connected to the pipeline through a test station that will allow the anode to be disconnected for testing.

7.4.2 Galvanic anodes shall be installed according to the design specifications and manufacturers recommendations.

7.4.3 Packaged galvanic anodes shall be backfilled with compacted native soil. Where anodes and special chemical backfill are provided separately, anodes shall be centered in special backfill which shall be compacted prior to backfilling with native soil. Care shall be exercised so that lead wires and connections are not damaged during backfill operations. Sufficient slack shall exist in lead wires to avoid strain.

7.4.4 Where anodes in bracelet form are used, pipe coating beneath the anode shall be free of holidays. Care shall be taken to prevent damage to the coating when installing bracelet anodes. After applications of concrete (if used) to pipe, all coating and concrete shall be removed from the anode surface. If reinforced concrete is used, there shall be no metallic contact between the anode and the reinforcing mesh or between the reinforcing mesh and the pipe.

7.4.5 Where a ribbon type anode is used, it can be trenched or plowed in, with or without special chemical backfill, as specified, and is generally laid parallel to the section of pipeline to be protected.

7.5 Inspection and Handling of Impression Current Systems

7.5.1 The rectifier or other power source shall be inspected for assurance that internal connections are mechanically secure and that no damage is apparent. Rating of the direct current power source shall comply with construction specifications. Care shall be exercised in handling and installing.

7.5.2 Impressed current anodes shall be inspected for conformance to specifications concerning correct anode material and size, length of lead wire, and secure cap, if used. Care shall be exercised to avoid cracking or damaging anodes during handling and installation. Impressed current anodes made of a thin emitter layer on substrate such as MMO or Pt/Nb shall be inspected for damage to the emitter layer prior to acceptance and installation and shall be rejected if substrate is exposed. Field-applied MMO repair coating is NOT acceptable.

7.5.3 Lead wires shall be carefully inspected to detect defects in insulation. Care shall be taken to avoid damage to insulation on wire. Defects in the lead wire shall be repaired or the anode shall be rejected. Anode-to-lead end resistance shall be supplied by the anode manufacturer for each anode assembly provided.

7.6 Installation Provisions for Impressed Current Systems

7.6.1 Rectifier or other power source shall be installed so that the possibility of damage or vandalism is minimized.

7.6.2 Wiring to rectifiers shall comply with local and the National Electrical Code (NFPA 70) and requirements of utility supplying power. An external disconnect switch on AC wiring shall be provided. The rectifier case shall be properly grounded.

7.6.3 When used, thermoelectric generator (TEG) cathodic protection rectifiers shall have a 'reverse current' device to prevent galvanic action between the pipe and ICCP anodes if the flame is extinguished.

7.6.4 Impressed current anodes can be buried vertically, horizontally, or in deep holes as indicated in construction specifications. Backfill material shall be placed to assure that there are no voids around anodes. Care shall be exercised during backfilling to avoid damage to the anode and wire.

7.6.5 The negative lead wire shall be permanently affixed to the structure. Connections to the rectifier shall be resilient and require verification prior to energization. Polarization measurements shall be taken after energization to ensure proper shift direction.

7.6.6 When below grade splicing of the header cable is required, an epoxy splice kit, or approved equal, shall be used.

7.6.7 Care shall be taken when installing direct burial cable to the anodes (positive lead wire) to avoid damage to insulation. Sufficient slack shall be left to avoid strain on all wires. Backfill material around the cable shall be free of rocks and foreign matter that might cause damage to the wire insulation when wire is installed in trench. Cable can be installed by plowing if proper precautions are taken. Direct burial cables shall include metallic warning tape installed above the wire at half of burial depth outside of anode bed installation areas.

7.7 Installation Provisions for Corrosion Control Test Stations, Connections and Bonds

7.7.1 Pipe and test lead wires shall be clean, dry, and free of foreign materials at points of connection when the connections are made. Connections of test lead wires to pipe shall be installed so they shall remain mechanically secure and electrically conductive.

7.7.2 All test lead wire attachments and all bare test lead wires shall be coated with an electrically insulating material. Where the pipe is coated, the insulating material shall be compatible with the pipe coating and wire insulation.

7.7.3 Conductors shall be color coded or otherwise permanently identified. Wire shall be installed with slack. Damage to insulation shall be avoided; repairs shall be made if damage occurs. Test leads shall not be exposed to excessive heat and sunlight. Above ground test stations are preferred. If test stations are flush with the ground, adequate conductor slack shall be provided with the test station to facilitate test connections.

7.7.4 Conductor connections at bonds to other structures or across insulating joints shall be mechanically secure, electrically conductive, and suitably coated. Bond connections shall be accessible for testing.

7.8 Other Consideration During Installation

7.8.1 Casing Installations: Sufficient inspection shall be made to ensure that no metallic contacts exist or are likely to develop between the casing and the carrier pipe.

7.8.2 Insulating Devices: Inspection and electrical measurements shall be sufficient to assure that electrical isolation is adequate.

8.0 CATHODIC PROTECTION DESIGN AND INSTALLATION RECORDS

8.1 The purpose of this section is to describe corrosion control records that document in a clear, concise, workable manner, data pertinent to the design, installation, operation, maintenance, and effectiveness of corrosion control measures.

8.2 The following records shall be stored in the "Corrosion Control" folder within the Documents Library and retained in accordance with Appendix C in OPS-STD-0017.

8.1.1 Relative to structure design, the following shall be recorded:

1. Coating material and application specifications.
2. Design and location of insulating devices, test leads and other test facilities, and details of other special corrosion control measures taken.

8.1.2 Relative to the design of corrosion control facilities, the following shall be recorded:

1. Results of current requirements tests, where made.
2. Results of soil resistivity surveys at groundbed locations, where made.
3. Interference tests and design of interference bonds and drainage switch installations.
   - Scheduling of interference tests, correspondence with Coordinating Committee, including Coordinating Committee minutes, and direct communication with the concerned companies.
   - Record of interference tests conducted, including location of tests, name of company involved, and results.

8.1.3 Relative to the installation of corrosion control facilities, the following shall be recorded:

1. Installation of cathodic protection facilities for impressed current systems:
   - Location and date placed in service.
   - Type, size, depth, backfill, and spacing of anodes.
   - Specifications of rectifier or other energy source.
2. Installation of Galvanic anode systems:
   - Location and date placed in service.
   - Type, size, backfill, and spacing of anodes.

	Engineering Standard	ENG-STD-0005	
MPLX	Cathodic Protection for Tank Bottoms	Page 1 of 11	
		DATE: 4/1/2021	Rev: 0

Contents

List of Figures

List of Tables

1.0 INTRODUCTION

1.1 Purpose

This Standard establishes minimum requirements for the cathodic protection of external tank bottoms to provide:

- Compliance with regulatory requirements (for facilities).
- The intended service life for the asset.
- Standardization of work procedures, materials, and inspection requirements as they pertain to cathodic protection of external tank bottoms.

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021

1.2 Scope

This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard

2.2 Industry Codes and Standards

- API 651-2007 Cathodic Protection for Aboveground Petroleum Storage Tanks – Third Edition
- NACE SP0169-2007 Control of External Corrosion on Underground or Submerged Metallic Piping Systems

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
-
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Anode	An electrode that is characterized by electron loss; typically oxidation.
Cathodic Protection	A technique to control corrosion of a metal surface by making it the cathode in an electrochemical cell.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Electrical Isolation	The condition of being substantially electrically separated from other metallic structures and the environment.
Galvanic Anode	Typically a prepackaged assembly consisting of an active metal (Mg, Zn, etc.). Generally any metal which is more electrochemically active in a multi-metal system.
Impressed Current	Direct current supplied by a power source external to the electrode system.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
Retrofitted Double Bottom Above-Ground Storage Tanks	An above-ground storage tank with a second bottom installed through a slot in the shell several inches above the original bottom with various media, often sand, between the two bottoms. Leak detection, release prevention, and possibly cathodic protection systems are installed between the bottoms.
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.

4.0 DETERMINATION OF NEED FOR CATHODIC PROTECTION

4.1 All new or modified aboveground tanks shall be evaluated as their need for cathodic protection. Corrosion surveys, operating records, and national, state and local code requirements shall be used in the above evaluation. It shall be recognized that external cathodic protection shall have no effect on internal tank corrosion. Guidelines to help determine the need for cathodic protection are as follows:

- Existing tanks being retrofitted with some mode of release prevention shall have a cathodic protection system installed, unless otherwise approved by the Regional Corrosion Control Team Lead or Engineer.
- New aboveground storage tanks at or over 16' diameter shall be provided with a suitable cathodic protection system designed to include provisions per API 651 S9 and NACE SP0169, unless otherwise approved by the Regional Corrosion Control Team Lead or Engineer. Tanks below 16' diameter shall be considered for the same.
- Where cathodic protection is deemed necessary, an impressed current system shall be used for existing tanks at or over 16' diameter.
- An economic analysis may be performed for tanks below 16' regarding the use of galvanic or impressed current cathodic protection system.
- Soil conditions shall be considered when determining a need for cathodic protection. In particular, soil pH, chloride content, sulfate content, and resistivity should be known. See API 651 and NACE SP0169 for the effect of these variables on corrosion rate to steel.
- Other factors that shall be considered when determining the need for cathodic protection system are contained in API 651 Section 3 and NACE SP0169.

5.0 ACCEPTABLE CATHODIC PROTECTION SYSTEM DESIGNS

All cathodic protection systems shall be installed in accordance with API 651 and receive final approval by the Regional Corrosion Control Team Lead or Engineer. All systems shall meet the -0.85 V IRF or 100 mV Polarization criteria specified in NACE SP0169 and shall be inspected in accordance with API 651.

5.1 New Construction

1. For new construction, if cathodic protection is deemed necessary based on the determination described in Section 4.0 of this Standard, an undertank cathodic protection system shall be installed. Figures 1-4 show typical designs for an undertank cathodic protection system.
    - If a tank liner is to be installed, it shall be of the geosynthetic clay liner (GCL) type. Polyethylene liners shall not be used as they will shield cathodic protection current from reaching the tank bottom if anodes are used outside of the liner.
2. Details of cathodic protection systems in the case of a) gravel ringwall or earth pad, or b) concrete ringwall are shown in Figure 8 and Figure 9, respectively.
3. A minimum of four (4) copper-copper sulfate and four (4) zinc permanent reference electrodes (placed at 0, 1/3, 2/3, and 11/12 of the tank radius) shall be installed below the external bottom of the tank.
    a. In addition, one (1) undertank perforated PVC reference electrode tube shall be installed for tanks with a diameter larger than 50 feet, while two (2) undertank perforated PVC reference electrode tubes shall be installed (perpendicular to each other) for tanks with a diameter larger than 100 feet.

5.2 Retrofitting Tanks with Cathodic Protection Systems

Cathodic protection systems may be added to existing tanks not undergoing a tank lift or a double bottom retrofit via one of the following methods:

1. Horizontal or vertical anodes distributed at the periphery of the tank, see Figure 5.
2. A deep anode system, see Figure 6.
3. Angle drilled anode systems extending under the tank bottom, see Figure 7.

6.0 FIGURES

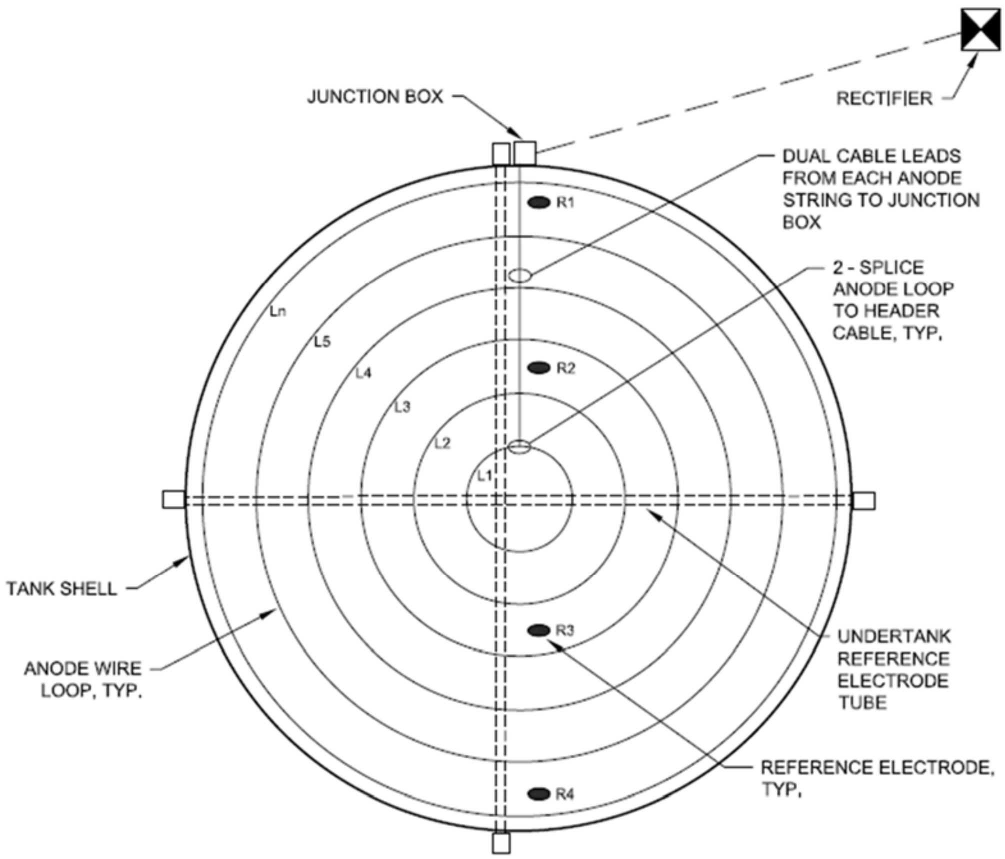


Figure 1 Anode Grid Layout for an Undertank Impressed Current Cathodic Protection System

Notes:

1. Ti ribbon typically, 0.25 in x 0.25 in, per ASTM 265 shall be specified.
2. Minimum sand cover between ribbon and upper tank floor shall be 6 inches.

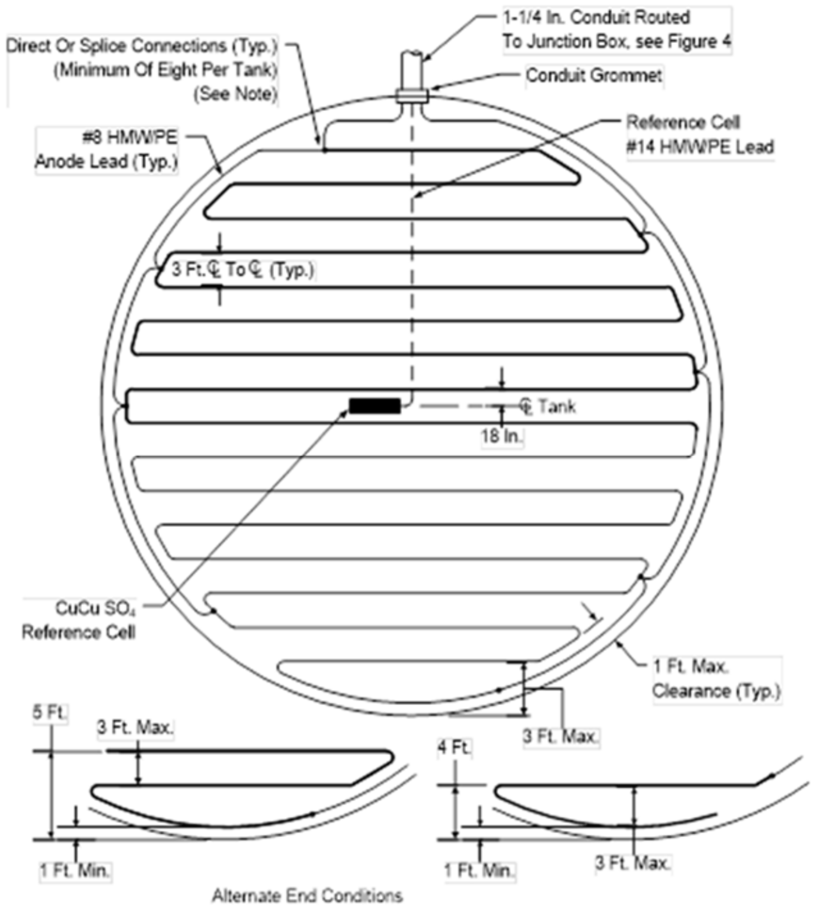


Figure 2 Anode Cable Layout for a Sacrificial Anode Cathodic Protection System

Notes: Alternate End Conditions

1. All spliced connections shall be thermite fusion welds.
2. All splices shall be sealed using a Durocast Universal Seal Kit, #SK-40 or approved equal.
3. Minimum sand cover between sacrificial anodes and upper tank floor shall be at least 3 inches.
4. Anode material shall be 1.2 lbs/ft zinc coil with cross-sectional measurements 5/8 in x 7/8 in or approved equivalent.

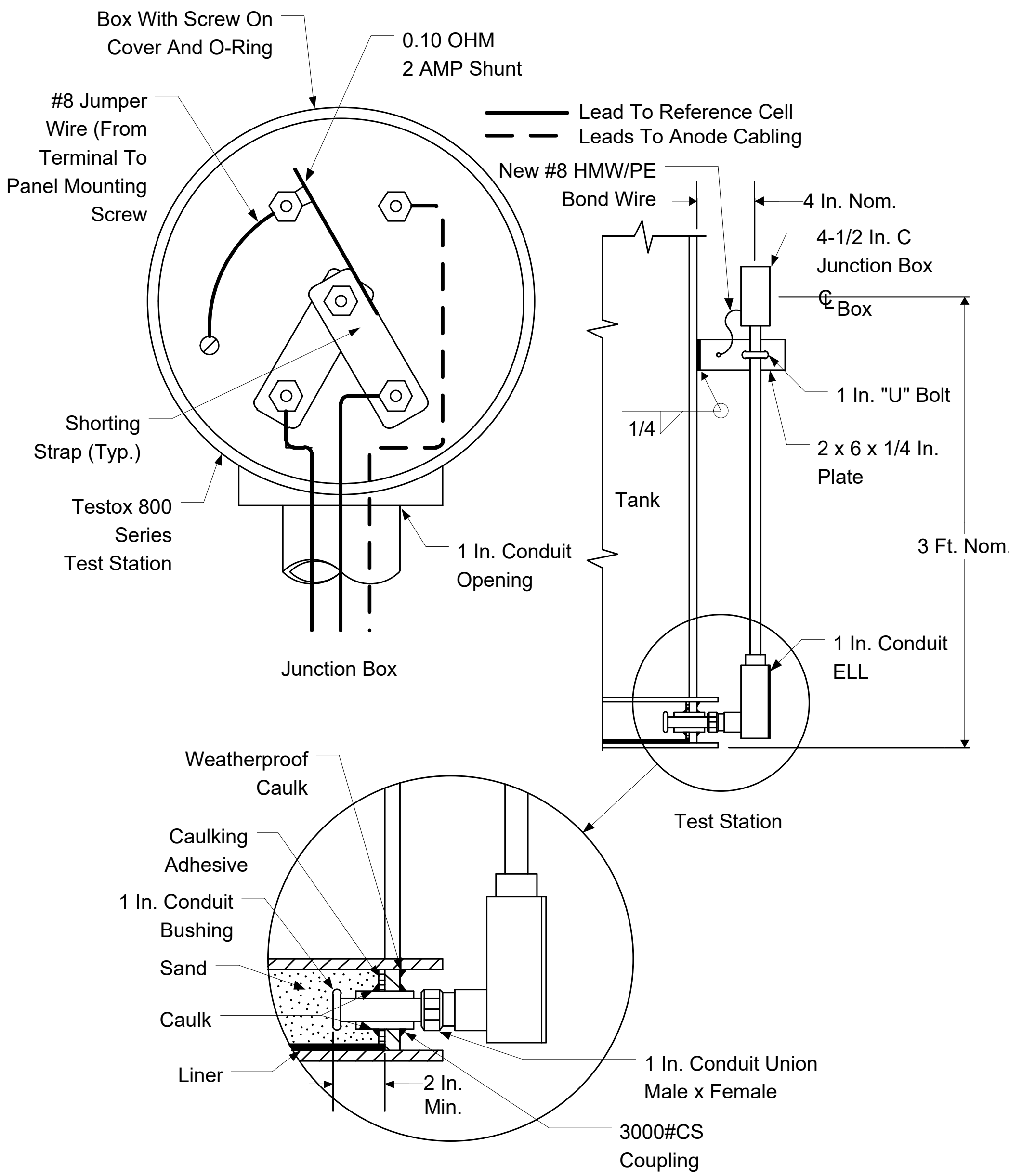


Figure 3 System Details for a Sacrificial Anode Cathodic Protection System

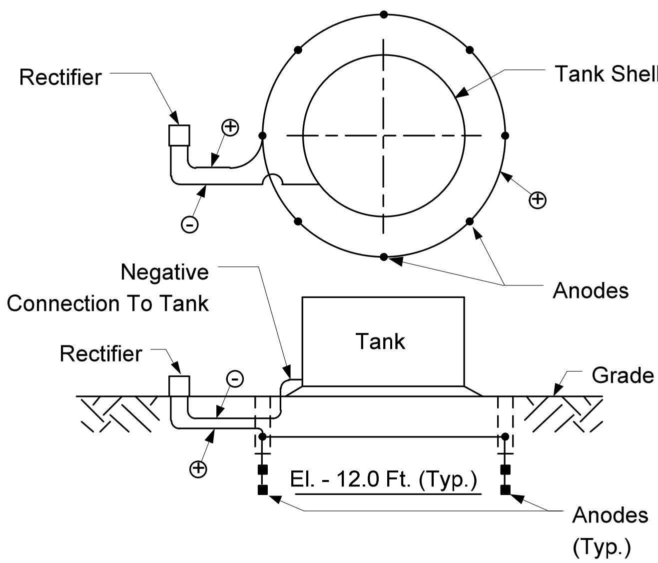


Figure 4 Impressed Current Cathodic Protection System with the Anodes Distributed Around the Periphery of the Tank

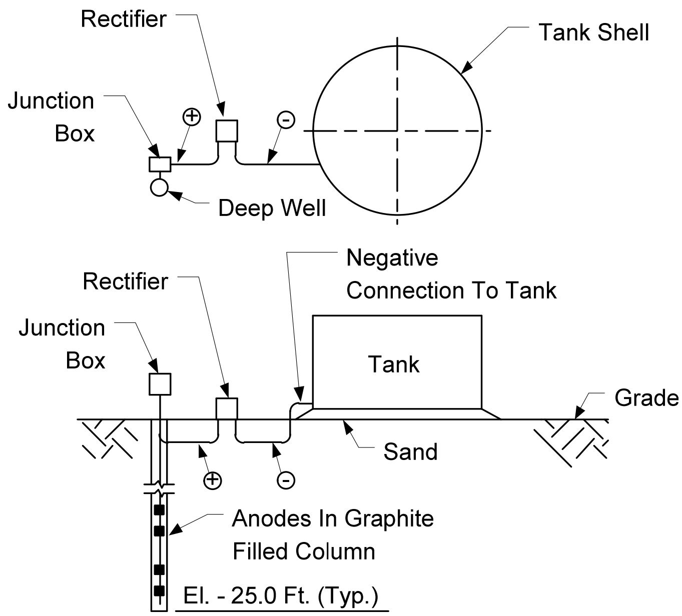


Figure 5 Impressed Current Cathodic Protection System with the Anodes Buried Deep Underground

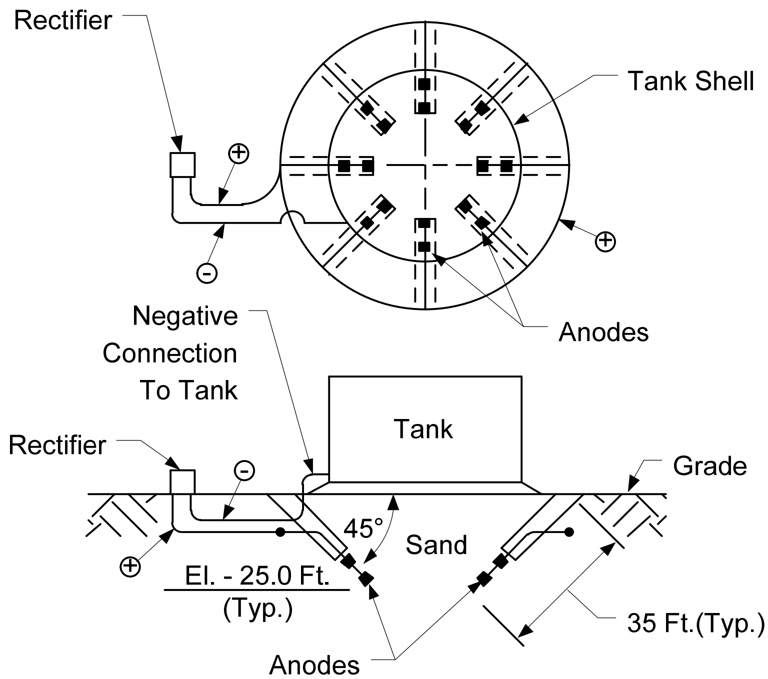


Figure 6 System Details for a Cathodic Protection System Gravel Ringwall or Earth Pad

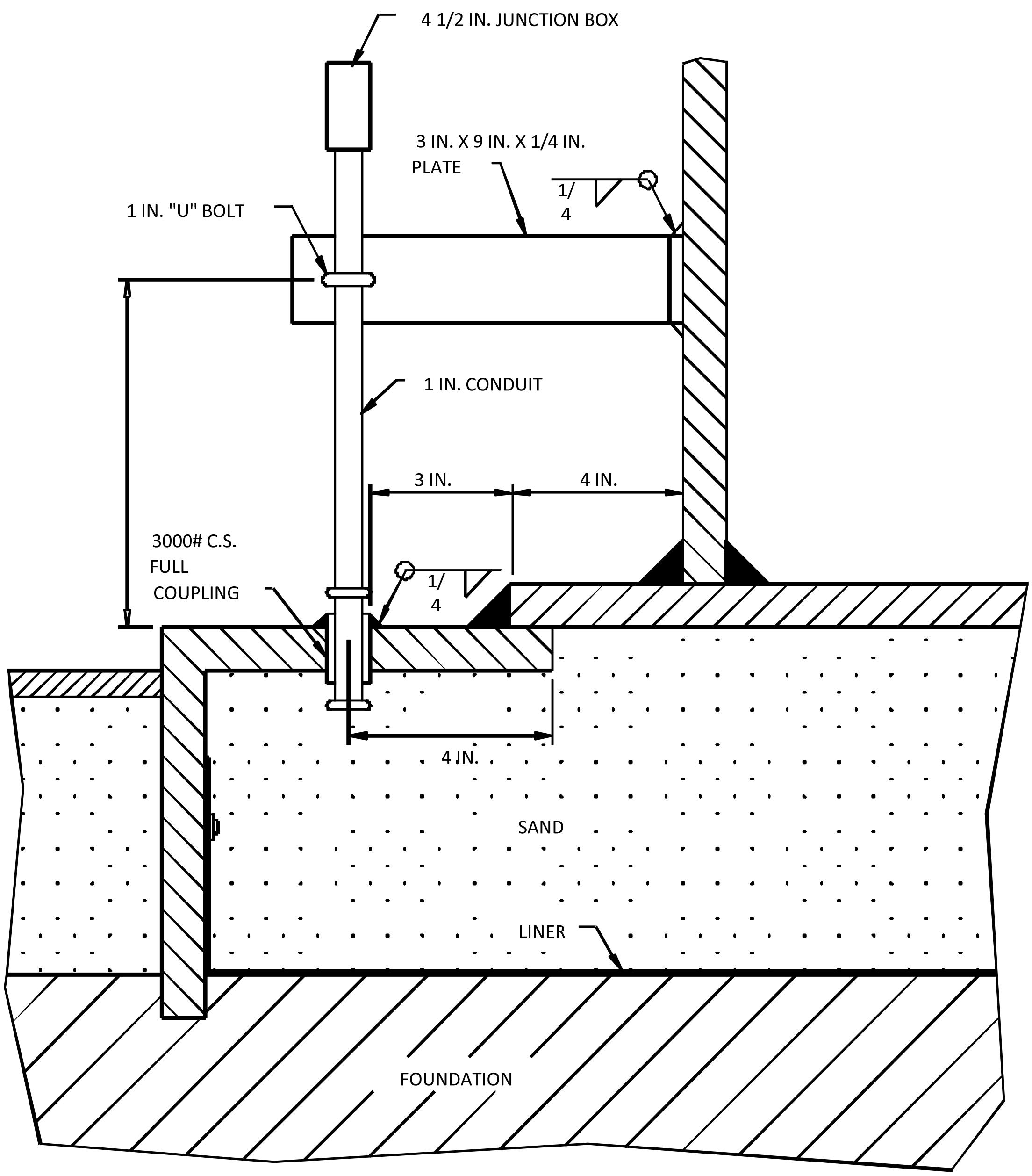


Figure 7 System Details for a Cathodic Protection System Gravel Ringwall or Earth Pad

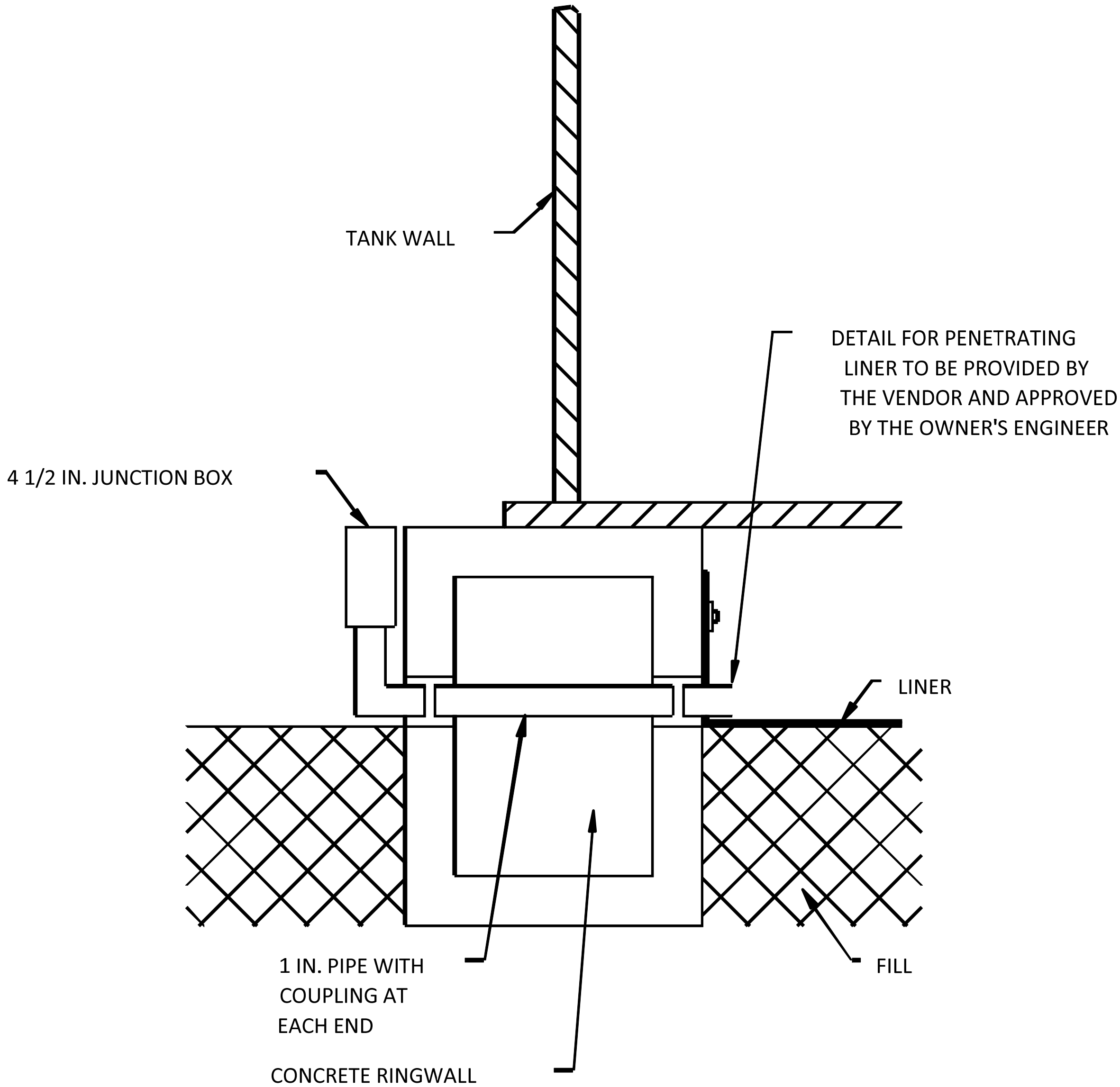


Figure 8 System Details for a Cathodic Protection System Concrete Ringwall

	Engineering Standard	ENG-STD-0006	
MPLX	Coating of Aboveground Pipelines and Facilities	Page 1 of 10	
		DATE: 4/1/2021	Rev: 0

Contents

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This standard provides requirements for surface preparation and coating applications on aboveground pipelines (e.g. valve site) and facilities (e.g. tanks, piping, vessels, non-galvanized structural steel, etc.) to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended coating service life for the asset.
- Standardization of work procedures, materials, color schemes, and inspection requirements as they pertain to field coating.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021
NOTICE: The information contained herein is the confidential property of MPLX unless another source is indicated. This material is subject to return on demand and must not be disclosed or reproduced without prior written consent by a duly authorized representative of MPLX.			
ENG-STD-0006 Coating of Aboveground Pipelines and Facilities Standard.docx			

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- ENG-STD-0006-FOR-01 Pipeline Coating Packet
- ENG-STD-0006-FOR-02 Tank Coating Packet
- ENG-STD-0006-FOR-03 Coating Variance Request Form
- ENG-STD-0009 - Coating of Transition Areas Standard

2.2 Industry Codes and Standards

Steel Structures Coating Council (SSPC)

- SSPC AB-1 Mineral and Slag Abrasives
- SSPC PA-1 Shop, Field and Maintenance Coating
- SSPC SP-1 Solvent Cleaning
- SSPC SP-2 Hand Tool Cleaning
- SSPC SP-3 Power Tool Cleaning
- SSPC SP-6 Commercial Blast Cleaning
- SSPC SP-10 Near-White Blast Cleaning
- SSPC SP-11 Power Tool Clean to Bare Metal

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Anchor Profile	The profile of minute projections formed on a metal surface by sandblasting, shot blasting, or chemical etching; used to enhance the adhesiveness of a surface coating.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Contractor	Company or business that agrees to furnish materials or perform specified services at a specified price and/or rate to the MPLX.
Dew Point	Temperature at which moisture will condense on the surface.
Inspector/ Person in Charge (PIC)	An MPLX appointed engineer or inspector.
Manufacturer	The recipient of a direct or indirect purchase order for materials and/or equipment. In this context, a direct order is one issued to a manufacturer by a contractor or MPLX. An indirect order is one issued to a manufacturer by a vendor (recipient of a direct order) for materials, fabricated components, or subassemblies.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.

4.0 REQUIREMENTS

4.1 Aboveground pipelines and facilities shall be coated to protect against atmospheric corrosion unless it can be demonstrated by test, investigation, or experience to the environment that corrosion shall only be a light surface oxide and/or not affect the safe operation of the pipeline or facility before the next scheduled inspection.

4.1.1 The exception does not apply to offshore splash zones or transition (soil-air) interfaces, which shall always be coated to protect against atmospheric corrosion.

4.2 The coating inspector shall, at a minimum, be NACE Coating Inspector Level I Certified.

4.3 The following items shall be cleaned and coated prior to delivery to the job site:

- Vessels, exchangers, and drums constructed of carbon steel.
- Carbon steel shop fabricated piping including nozzles, attachments and backs of flanges, but not machined surfaces. Threads and flange faces shall not be coated.
- Structural steel that is not galvanized shall be coated including contact surfaces. Coating applied on surfaces to be fireproofed shall be compatible with the fireproof material to be used.
- The exterior of heater and fired heater jackets, walks, handrails, supports, breaching, ducts, and stacks shall all be coated.

4.4 The following surfaces shall be coated with the manufacturer's standard surface preparation and finish:

- Hand or mechanically operated valves and piping specialties such as traps, strainers, and filters.
- Pumps, bases, compressors, motors, turbines, conveyors, and similar machinery.
- Electrical equipment, instruments, gages, and local instrument panels shall be finished with the manufacturer's standard finish. Instrument panels in control rooms shall be finished as described in the instrument specifications.

If the manufacturer's standard does not include coating, then the surfaces shall be coated per Appendix A "Table 3 - Coating Systems for Aboveground Pipelines and Facilities".

4.5 The coating contractor shall properly clean and spot prime all damaged areas of shop applied primers (or previously applied coatings) before applying succeeding coatings. Any items not primed in the shop, but specified for a shop prime coat, shall be cleaned and primed in the field.

4.6 It is intended that all exposed carbon steel surfaces, including surfaces of insulated equipment, shall be coated. Insulated stainless steel shall be coated. The following shall be evaluated on an individual basis:

- Grating
- Stair treads
- Galvanized steel
- Vendor shop finished items
- Cast-iron hardware

4.7 The following surfaces shall not be coated unless specifically required MPLX or otherwise noted in this Standard or in the Job Specifications:

- Non-ferrous metals such as but not limited to aluminum, copper and copper alloys
- Machined parts of operating equipment
- Gasket surfaces
- Exterior surface of insulation
- Composites, plastics and other resinous products
- Brick, concrete, (including precast products), fiber board products, and wood products
- Nameplates, identification tags, and sight glasses
- Weld joint areas of piping and fittings to be field welded.

4.8 Operating metal surface temperature shall be specified for each component to be coated. If none is available, the specified design temperature shall be used.

4.9 This Standard does not cover architectural coating.

5.0 SURFACE PREPARATION

5.1 Surfaces shall be prepared and cleaned in accordance with the SSPC specifications indicated in the Coating Schedule, and as indicated in the coat manufacturer's printed instructions specifying surface preparation for the coat system to be used.

5.2 Where SSPC SP-1, SSPC SP-2, or SSPC SP-3 is indicated for metal surfaces, it means that the surface shall be clean, dry, and free of dirt, dust, oils, or any contamination that would adversely affect the adhesion or appearance of the coating.

5.3 Hand and power tool cleaning shall be conducted so as to remove burrs, weld spatter, shape edges and other irregularities, but to minimize polishing or burnishing of the prepared surface.

5.4 Abrasive blasting shall not be performed if the steel surface temperature is less than 5°F above the dew point or if the relative humidity is greater than 80%. If the prepared surface is degraded or contaminated subsequent to surface preparation and prior to coat application, the surface shall be restored to the specified cleanliness. See Appendix B "Table 4 - Dew Point Calculation Chart" to determine dew point relative to ambient air temperature and humidity.

5.5 The abrasive media used in blast cleaning shall meet SSPC AB-1 requirements.

5.6 Studies have shown that coating over abrasive blasted steel has lasted up to three times as long as wire brushed steel. Various abrasives can be selected to produce varying degrees of anchor patterns. Some of the more common ones are Black Beauty and VitroGrit, see Table 2.

Table 2 Common Abrasives

Anchor Profile	Product
1.0 mil	Black Beauty 3060 - X-Fine Grade
1.5 mil	Black Beauty 3060 - X-Fine Grade
2.0 mil	Black Beauty 2040 - Fine Grade
2.5 mil	Black Beauty 2040 - Fine Grade
3-4 mil	Black Beauty 1240 - Medium Grade
1.5+ mil	VitroGrit #70 - Super Fine
1.5 - 2.5 mil	VitroGrit #50 - Fine
2.5 - 3.5 mil	VitroGrit #30/50 - Medium/Fine
3.0 - 4.0 mil	VitroGrit #16/30 - Coarse/Medium

6.0 COATING MATERIALS

6.1 Only the products listed in Appendix A "Table - Coating Systems for Aboveground Pipelines and Facilities" shall be used, unless approved by the Regional Corrosion Control Team Lead or Engineer

6.1.1 The use of tape wrap is acceptable on aboveground pipeline spans as long as it is ultraviolet (UV) resistant or protected with a UV protective tape. Acceptable tape wrap products are listed in Appendix A of ENG-STD-0009.

6.2 Any deviations from the products listed in Appendix A shall be accompanied with a completed and signed copy of the ENG-STD-0006-FOR-03 "Coating Variance Request Form".

7.0 APPLICATION

7.1 All work shall be performed in accordance with SSPC PA-1 "Shop, Field and Maintenance Coating", the coating manufacturer's recommendations and this Standard.

7.2 All materials shall be applied in smooth, even coats without runs, sags, or bare spots. Dry film thickness where indicated in Appendix A "Table 3 - Coating Systems for Aboveground Pipelines and Facilities" is the minimum required.

7.3 All valve stems, glass, moving parts, bearings, couplings, shafts, lubricant fittings, equipment nameplates, or other important or sensitive parts shall be protected from damage by coating operations including over spray, dripping, and sandblasting. Any coat falling on, or applied to, such surfaces shall be removed. All such parts may be coated with rust preventatives or strippable coatings.

7.4 The air, surface, and coating temperature at the time of application shall be at a minimum temperature of 50°F, unless specified by Manufacturer, and 5°F above dew point. If construction completion occurs during unsuitable weather, it is not detrimental to leave the steel uncoated until weather conditions are suitable for coating. See Appendix A "Table 4 - Dew Point Calculation Chart" to determine dew point relative to ambient air temperature and humidity.

8.0 INSPECTION

8.1 All coated pipeline and tank surfaces shall be visually inspected. Holiday testing of the coating may be required at the request of the Regional Corrosion Control Team Lead or Engineer. All holidays and areas of damaged coating shall be repaired using compatible system/material(s) immediately after detection. All coating repairs shall be inspected after repair coating system has cured sufficiently to prevent damage.

CAUTION: *Holiday voltages shall be adequate in accordance with coating manufacturer's specifications but shall not exceed coating manufacturer's specifications. Exceeding coating manufacturer's recommendations can damage the coating and cause premature failures.*

8.2 For holiday detectors with built-in metering ability, the unit's readout voltage shall be recorded in open circuit (HV) and shorted (ground to coil) state at the start of each coating inspection effort.

8.3 For High Voltage (>100 V) holiday detectors without built-in metering, the holiday detector shall be calibrated using the manufacturer's recommended calibration tool at the start of each coating inspection effort.

8.4 For Low Voltage (≤100 V) holiday detectors without built-in metering, the holiday detector shall be calibrated using the manufacturer's recommended calibration tool, or a calibrated digital multimeter in "DC Volts" mode, at the start of each coating inspection effort.

8.5 All holiday detectors shall be calibrated annually by the manufacturer.

8.6 The inspection times and voltage readings shall be recorded as part of the coating inspection documentation process.

8.7 The holiday detector coil, brush, and/or other contact devices shall contact the entire coated surface.

8.8 The coating contractor shall permit inspection of all phases of work by the Inspector/PIC such as:

- Atmospheric conditions, such as temperature, humidity, dew point
- Surface preparation equipment
- Steel surfaces prior to surface preparation
- Steel surfaces following cleaning and surface preparation
- Coat application equipment
- Coat material containers and ID labels
- Coat application process

- Coat film quality and thickness, wet and dry

8.9 The Inspector/PIC shall, for each item coated, determine and record the information requested on ENG-STD-0006-FOR-01 "Pipeline Coating Packet" and/or ENG-STD-0006-FOR-02 "Tank Coating Packet". The contractor representative shall maintain this record if the Inspector/PIC is not present.

APPENDIX A COATING SYSTEMS FOR ABOVEGROUND PIPELINES AND FACILITIES

Table 3 Coating Systems for Aboveground Pipelines and Facilities

Environment	System No	Category Items	Service Temperature	Ambient Application Temperature (Primer Coat)	Minimum Surface Prep, SSPC SP	Anchor Profile, Mils	Primer Coat	Intermediate Coat	Top Coat
Marine Industrial Environment	AS-1*	Bare or Previously Coated Exterior Carbon Steel	Up to 200°F	Between 0°F and 130°F	SP-6	1.0 - 3.0	Carboline Carbozinc 11 Series (IOZ) *(Touch up of Carbozinc 11 should be done with Carbozinc 859VOC Organic Zinc Primer)* **Total DFT:** 2 to 3 mils **Color:** 0300 (Green)	Carboline Carboguard 60 or 890VOC/891VOC (AEM) **Total DFT:** 4 to 6 mils **Color:** 0700 (Light Gray)	Carboline Carboxane 2100 Series (PS) **Total DFT:** 3 to 7 mils **Color:** 1864 (Vestal White)
Marine Industrial Environment	AS-2	Bare or Previously Coated Exterior Carbon Steel	Up to 200°F	Between 40°F and 100°F	SP-6	2.0 - 3.0	Sherwin Williams Zinc Clad XI(IOZ) **Total DFT:** 2 to 4 mils **Color:** Gray	Sherwin Williams Macropoxy 646-100 (AEM) **Total DFT:** 5 to 10 mils **Color:** Multiple	Sherwin Williams Sherloxane 800 (PS) **Total DFT:** 4 to 6 mils **Color:** Multiple
Inland Industrial Environment	AS-3*	Bare or Previously Coated Exterior Carbon Steel	Up to 200°F	Between 50°F and 110°F	SP-6	1.5 - 3.0	Carboline Carboguard 60 or 890VOC/891VOC (AEM) **Total DFT:** 4 to 6 mils **Color:** O700 (Light Gray)	-	Carboline Carboxane 2100 Series (PS) **Total DFT:** 3 to 7 mils **Color:** 1864 (Vestal White)
Inland Industrial Environment	AS-4	Bare or Previously Coated Exterior Carbon Steel	Up to 200°F	Between 35°F and 140°F	SP-6	2.0	Sherwin Williams Recoatable Epoxy Primer (AEM) **Total DFT:** 4 to 6 mils **Color:** Multiple	-	Sherwin Williams Hi-Solids Polyurethane (PU) **Total DFT:** 3 to 5 mils **Color:** Multiple
Inland Industrial Environment	AS-5	Bare or Previously Coated Exterior Carbon Steel	Up to 200°F	Between 35°F and 120°F	SP-6	2.0 - 3.0	Sherwin Williams Dura-Plate 301 (AEM) **Total DFT:** 5 to 10 mils **Color:** Multiple	-	Sherwin Williams Sherloxane 800 (PS) **Total DFT:** 4 to 6 mils **Color:** Multiple
Inland Industrial Environment	AS-6	Bare or Previously Coated Exterior Carbon Steel	Up to 200°F	Between 40°F and 140°F	SP-6	2.0	Sherwin Williams Macropoxy 646-100 (AEM) **Total DFT:** 5 to 10 mils **Color:** Multiple	-	Sherwin Williams Acrolon 218HS (PU) **Total DFT:** 3 to 5 mils **Color:** Multiple
Industrial Environment		Bare or Previously Coated Exterior Carbon Steel or Galvanized Steel	Up to 200°F	Between 20°F and 100°F	SP-2	-	Carboline Carbomastic 615 AL (AEM) **Total DFT:** 5 to 10 mils **Color:** C901 (Aluminum)	-	Carboline Carboxane 2100 Series (PS) **Total DFT:** 3 to 7 mils **Color:** 1864 (Vestal White)
Industrial Environment	AS-7	Bare or Previously Coated Exterior Carbon Steel or Galvanized Steel	Up to 200°F	Between 50°F and 100°F	SP-2	-	Carboline Carbomastic 15 (EM) **Total DFT:** 3 to 5 mils **Color:** C901 (Aluminum)	-	Carboline Carbothane 134 Series (PU) **Total DFT:** 2 to 3 mils **Color:** Multiple
Industrial Environment		Bare or Previously Coated Exterior Carbon Steel or Galvanized Steel	Up to 200°F	Between 35°F and 120°F	SP-2	-	Sherwin Williams Epoxy Mastic Alum II (EM) **Total DFT:** 4 to 6 mils **Color:** Aluminum	-	Sherwin Williams Sherloxane 800 (PS) **Total DFT:** 4 to 6 mils **Color:** Multiple
Industrial Environment	AS-8	Bare or Previously Coated Exterior Carbon Steel	Up to 150°F	Between -20°F and 120°F *(Surface must be above 50°F)*	SP-2	-	Denso Protal ST Epoxy Mastic (EM) **Total DFT:** 8 to 10 mils **Color:** Gray	-	Denso Archco 65 (PU) **Total DFT:** 3 to 5 mils **Color:** Multiple
Industrial Environment	AS-9	Exterior Carbon Steel Insulating Coating	Up to 325°F	Between 40°F and 200°F	SP-6	1.0 - 2.0	Tnemec Series 1224 Epoxoline WB (WBE) **Total DFT:** 4 to 8 mils **Color:** White	Tnemec Aerolon Acrylic Series 971 (TIC) **Total DFT:** 80 to 100 mils **Color:** Yellow	Tnemec Enduratone Series 1028T (WA) **Total DFT:** 2 to 3 mils **Color:** Multiple
Industrial Environment	AS-10	Bollards and Guard Rails, CMU Buildings/ Structures, Firewater Lines, Safety Showers	Up to 235°F	Between 50°F and 110°F	SP-2	-	-	-	Carboline Carbocrylic 3359 Series (WA) **Total DFT:** 3 to 5 mils **Color:** Multiple

Table 3 Coating Systems for Aboveground Pipelines and Facilities

Environment	System No	Category Items	Service Temperature	Ambient Application Temperature (Primer Coat)	Minimum Surface Prep, SSPC SP	Anchor Profile, Mils	Primer Coat	Intermediate Coat	Top Coat
Industrial Environment		Bollards and Guard Rails, CMU Buildings/ Structures, Firewater Lines, Safety Showers	Up to 250°F	Between 50°F and 120°F	SP-2	-	-	-	Sherwin Williams Pro Industrial Acrylic (WA) **Total DFT:** 2 to 4 mils **Color:** Multiple
Industrial Environment	AS-11*	Exterior of Floating Roof or Insulated Carbon Steel (Up to 140°F)	Up to 300°F (Carboguard 60) Up to 300°F (Carboguard 890VOC/891VOC)	Between 50°F and 110°F	SP-6	1.5 - 3.0	Carboline Carboguard 60 or 890VOC/891VOC (AEM) **Total DFT:** 4 to 6 mils **Color:** 0700 (Light Gray)	-	Carboline Carboguard 60 or 890VOC/891VOC (AEM) **Total DFT:** 4 to 6 mils **Color:** 0800 (White)
Industrial Environment		Exterior of Floating Roof or Insulated Carbon Steel (Up to 140°F)	Up to 250°F	Between 40°F and 120°F	SP-6	2.0-3.0	Sherwin Williams Macropoxy 646-100 (AEM) **Total DFT:** 4 to 6 mils **Color:** Light Gray	-	Sherwin Williams Macropoxy 646-100 (AEM) **Total DFT:** 4 to 6 mils **Color:** White
Industrial Environment	AS-12	Insulated Carbon Steel	Up to 425°F	Between 50°F and 100°F	SP-10	2.0 - 3.0	Carboline Thermaline 450 (NE) **Total DFT:** 4 to 8 mils **Color:** 0500 (Red)	-	Carboline Thermaline 450 (NE) **Total DFT:** 4 to 8 mils **Color:** 5742 (Gray)
Industrial Environment		Insulated or Non-Insulated Carbon Steel	Up to 1200°F	Between 45°F and 100°F	SP-10	2.0 – 3.0	Carboline Thermaline Heat Shield **Total DFT:** 7 to 10 mils **Color:** (0700) Metallic Grey, (J700) Darker Metallic Grey	-	-
Industrial Environment	AS-13	Insulated or Non-Insulated Carbon Steel	Up to 1000°F, with Peaks to 1200°F	Between 50°F and 120°F	SP-10	1.5 - 2.0	Dampney Thurmalox 245 (HRS) **Total DFT (Insulated):** 3 to 4 mils **Total DFT (Non-Insulated):** 1.5 to 2 mils **Color:** Gray	-	Dampney Thurmalox 230 (HRS) *Only use a top coat if steel is Non-Insulated **Total DFT:** 1.5 to 2 mils **Color:** Gray
Industrial Environment	AS-14	Insulated Stainless Steel	Up to 1000°F, with Peaks to 1100°F	Between 50°F and 120°F	SP-1	-	Dampney Thurmalox 70 (HRS) **Total DFT:** 3 to 4 mils (w/ 2 coats) **Color:** Black	-	-

Type Codes:

AEM	Aluminum Epoxy Mastic
EM	Epoxy Mastic
HRS	High Resistance Silicone
IOZ	Inorganic Zinc
NE	Novolac Epoxy
PS	Polysiloxane
PU	Polyurethane
TIC	Thermal Insulation
WA	Waterborne Acrylic
WBE	Water-Based Epoxy

APPENDIX B DEW POINT CALCULATION CHART

Table 4 Dew Point Calculation Chart

Air Ambient Temperature °F		20	30	40	50	60	70	80	90	100	110	120
% Relative Humidity	90	18	28	37	47	57	67	77	87	97	107	117
	85	17	26	36	45	55	65	75	84	95	104	113
	80	16	25	34	44	54	63	73	82	98	102	110
	75	15	24	33	42	52	62	71	80	91	100	108
	70	13	23	31	40	50	60	68	78	88	96	105
	65	12	20	29	38	47	57	66	76	85	93	103
	60	11	19	27	36	45	55	64	73	83	92	101
	55	9	17	25	34	43	53	61	70	80	89	98
	50	6	15	23	31	40	50	59	67	77	86	94
	45	4	13	21	29	37	47	56	64	73	82	91
	40	1	11	18	26	35	43	52	61	69	78	87
	35	-2	8	16	23	31	40	48	57	65	74	83
	30	-6	4	13	20	28	36	44	52	61	69	77

MPLX	Pipeline Coating Packet	ENG-STD-0006-FOR-01	
	Form	Page 1 of 8	
		DATE: 4/1/2021	Rev: 0

Daily Progress Report

Project Information

Project Name / AFE #	
Location of Work	
Pipe Description	
Upstream Weld # to Downstream Weld # (or) Facility	

Summary

Mainline	# of Welds	Blast Media	Coating	Estimated Surface Area (ft^2)	Station # to Station#		Station GPS to Station GPS	
Fittings/Laterals	# of Welds	Blast Media	Coating	Estimated Surface Area (ft^2)	Station # to Station#		Station GPS to Station GPS	
HDD/Road Bores	# of Welds	Blast Media	Coating	Estimated Surface Area (ft^2)	Station # to Station#		Station GPS to Station GPS	
Facility Piping	# of Welds	Blast Media	Coating	Estimated Surface Area (ft^2)	Facility		Facility GPS	

MPLX	Pipeline Coating Packet	ENG-STD-0006-FOR-01	
	Form	Page 2 of 8	
		DATE: 4/1/2021	Rev: 0

Daily Progress Report

Description of Work Completed Today in Detail

Inspector's Signature	Date
NACE Certification #	

	Pipeline Coating Packet	ENG-STD-0006-FOR-01	
	Form	Page 3 of 8	
		DATE: 4/1/2021	Rev: 0

Surface Preparation

Project Information

Project Name / AFE #	
Location of Work	
Pipe Description	
Upstream Weld # to Downstream Weld # (or) Facility	

Ambient Conditions

Date				
Inspector & NACE Certification #				
Inspection Tool / Serial #				
Time				
Item / Area Description				
Air Temperature				
Relative Humidity				
Dew Point				
Surface Temperature				
Comments				

Blasted Surface Measurements

SSPC Specification	
Specified Anchor Profile	
Blast Media	
Inspector & NACE Certification #	
Inspector Tool / Serial #	
Comments	

	Pipeline Coating Packet	ENG-STD-0006-FOR-01	
	Form	Page 4 of 8	
		DATE: 4/1/2021	Rev: 0

Surface Preparation

Weld #	Weld Type	Station
PRESS-0-FILM HERE	PRESS-0-FILM HERE	PRESS-0-FILM HERE
Weld #	Weld Type	Station
PRESS-0-FILM HERE	PRESS-0-FILM HERE	PRESS-0-FILM HERE
Weld #	Weld Type	Station
PRESS-0-FILM HERE	PRESS-0-FILM HERE	PRESS-0-FILM HERE
Weld #	Weld Type	Station
PRESS-0-FILM HERE	PRESS-0-FILM HERE	PRESS-0-FILM HERE
Weld #	Weld Type	Station
PRESS-0-FILM HERE	PRESS-0-FILM HERE	PRESS-0-FILM HERE

Note: Place an X in the corner box indicating in which quadrant the reading was taken.

	Pipeline Coating Packet	ENG-STD-0006-FOR-01	
	Form	Page 5 of 8	
		DATE: 4/1/2021	Rev: 0

Application Parameters

Project Information

Project Name / AFE #	
Location of Work	
Pipe Description	
Upstream Weld # to Downstream Weld # (or) Facility	

Ambient Conditions

Date				
Inspector & NACE Certification #				
Inspection Tool / Serial #				
Time				
Item / Area Description				
Air Temperature				
Relative Humidity				
Dew Point				
Surface Temperature				
Comments				

Material Information

	Stripe Code	Primer Coat	Intermediate Coat	Top Coat
Product Name				
Batch #				
Batch Date				
Second Part				
Thinner Used				
Application Method				
Paint Used (gal)				
Area Painted (Sq Ft)				
Wet Film – Measured				
Dry Film – Measured				

MPLX	Pipeline Coating Packet	ENG-STD-0006-FOR-01
	Form	Page 6 of 8
		DATE: 4/1/2021 / Rev: 0

Material Information

	Stripe Code	Primer Coat	Intermediate Coat	Top Coat
Comments				

Dry Film Thickness

Project Information

Project Name / AFE #	
Location of Work	
Pipe Description	
Upstream Weld # to Downstream Weld # (or) Facility	

Dry Film Thickness Measurements

Inspector & NACE Certification #	
Inspection Tool / Serial #	
Comments	

Item / Area Description	Spot Meas	Readings 1	Readings 2	Readings 3	Avg	Item / Area Description	Spot Meas	Readings 1	Readings 2	Readings 3	Avg
	A						A				
	B						B				
	C						C				
	D						D				
	E						E				
Specified DFT Range	mils					Specified DFT Range	mils				
DFT Range Achieved	mils					DFT Range Achieved	mils				

Item / Area Description	Spot Meas	Readings 1	Readings 2	Readings 3	Avg	Item / Area Description	Spot Meas	Readings 1	Readings 2	Readings 3	Avg
	A						A				
	B						B				
	C						C				
	D						D				
	E						E				

Specified DFT Range	mils		Specified DFT Range	mils	
DFT Range Achieved	mils		DFT Range Achieved	mils	

Note: Complete a separate report for change in Coating Material, Application Method, or Batch.

Dry Film Thickness

Item / Area Description	Spot Meas	Readings			Avg	Item / Area Description	Spot Meas	Readings			Avg
		1	2	3				1	2	3	
	A						A				
	B						B				
	C						C				
	D						D				
	E						E				
Specified DFT Range	mils					Specified DFT Range	mils				
DFT Range Achieved	mils					DFT Range Achieved	mils				
Item / Area Description	Spot Meas	Readings			Avg	Item / Area Description	Spot Meas	Readings			Avg
		1	2	3				1	2	3	
	A						A				
	B						B				
	C						C				
	D						D				
	E						E				
Specified DFT Range	mils					Specified DFT Range	mils				
DFT Range Achieved	mils					DFT Range Achieved	mils				

Note: Complete a separate report for change in Coating Material, Application Method, or Batch.

MPLX	Pipeline Coating Packet	ENG-STD-0006-FOR-01	
	Form	Page 8 of 8	
		DATE: 4/1/2021	Rev: 0

Holiday Testing

Project Information

Project Name / AFE #	
Location of Work	
Pipe Description	
Upstream Weld # to Downstream Weld # (or) Facility	

Holiday Detection Report

Inspector & NACE Certification #	
Inspection Tool / Serial #	
Calibration Tool / Serial #	
Comments	

Date	Station Start	GPS Start	Station End	GPS End	Voltage	Repairs	Comments

MPLX	Tank Coating Packet	ENG-STD-0006-FOR-02
	Form	Page 1 of 7
		DATE: 4/1/2021 / Rev: 0

Daily Progress Report

Project Information

Project Name / AFE #	
Location of Work	
Tank Description	

Summary

Shell Steel (Interior / Exterior)	Location	Estimated Surface Area (ft^2)	Blast Media	Coating
Floor (Interior / Exterior)	Location	Estimated Surface Area (ft^2)	Blast Media	Coating
Roof (Interior / Exterior)	Location	Estimated Surface Area (ft^2)	Blast Media	Coating
Piping	Location	Estimated Surface Area (ft^2)	Blast Media	Coating
Final Jeep	Location	Estimated Surface Area (ft^2)	Blast Media	Coating

Description of Work Completed Today in Detail

Inspector's Signature	Date
NACE Certification #	

	Tank Coating Packet	ENG-STD-0006-FOR-02	
MPLX®	Form	Page 2 of 7	
		DATE: 4/1/2021	Rev: 0

Surface Preparation

Project Information

Project Name	
Location of Work	
Tank Description	

Ambient Conditions

Date				
Inspector & NACE Certification #				
Inspection Tool / Serial #				
Time				
Location				
Air Temperature				
Relative Humidity				
Dew Point				
Surface Temperature				
Comments				

Blasted Surface Measurements

SSPC Specification	
Specified Anchor Profile	
Blast Media	
Inspection Tool / Serial #	
Comments	

	Tank Coating Packet	ENG-STD-0006-FOR-02	
MPLX	Form	Page 3 of 7	
		DATE: 4/1/2021	Rev: 0

Surface Preparation

Location		
PRESS-0-FILM HERE	PRESS-0-FILM HERE	PRESS-0-FILM HERE
Location		
PRESS-0-FILM HERE	PRESS-0-FILM HERE	PRESS-0-FILM HERE
Location		
PRESS-0-FILM HERE	PRESS-0-FILM HERE	PRESS-0-FILM HERE
Location		
PRESS-0-FILM HERE	PRESS-0-FILM HERE	PRESS-0-FILM HERE
Location		
PRESS-0-FILM HERE	PRESS-0-FILM HERE	PRESS-0-FILM HERE

Note: Place an X in the corner box indicating in which quadrant the reading was taken.

	Tank Coating Packet	ENG-STD-0006-FOR-02	
	Form	Page 4 of 7	
		DATE: 4/1/2021	Rev: 0

Application Parameters

Project Information

Project Name / AFE #	
Location of Work	
Tank Description	

Ambient Conditions

Date				
Inspector & NACE Certifcation #				
Inspection Tool / Serial #				
Time				
Item / Area Description				
Air Temperature				
Relative Humidity				
Dew Point				
Surface Temperature				
Paint Temperature				
Comments				

Material Information

	Stripe Coat	Primer Coat	Intermediate Coat	Top Coat
Product Name				
Batch				
Batch Date				
Second Part				
Thinner Used				
Application Method				
Paint Used (Gal)				
Area Pained (Sq Ft)				
Wet Film – Measured				
Dry Film – Measured				
Comments				

	Tank Coating Packet	ENG-STD-0006-FOR-02	
	Form	Page 5 of 7	
		DATE: 4/1/2021	Rev: 0

Dry Film Thickness

Project Information

Project Name / AFE #	
Location of Work	
Tank Description	

Dry Film Thickness Measurements

Inspector & NACE Certification #	
Inspection Tool / Serial #	
Comments	

Item / Area Description	Spot Meas	Readings			Avg	Item / Area Description	Spot Meas	Readings			Avg
		1	2	3				1	2	3	
	A						A				
	B						B				
	C						C				
	D						D				
	E						E				
Specified DFT Range	mils					Specified DFT Range	mils				
DFT Range Achieved	mils					DFT Range Achieved	mils				
Item / Area Description	Spot Meas	Readings			Avg	Item / Area Description	Spot Meas	Readings			Avg
		1	2	3				1	2	3	
	A						A				
	B						B				
	C						C				
	D						D				
	E						E				
Specified DFT Range	mils					Specified DFT Range	mils				
DFT Range Achieved	mils					DFT Range Achieved	mils				

Note: Complete a separate report for change in Coating Material, Application Method, or Batch.

MPLX	Tank Coating Packet	ENG-STD-0006-FOR-02	
	Form	Page 6 of 7	
		DATE: 4/1/2021	Rev: 0

Dry Film Thickness

Item / Area Description	Spot Meas	Readings			Avg	Item / Area Description	Spot Meas	Readings			Avg
		1	2	3				1	2	3	
	A						A				
	B						B				
	C						C				
	D						D				
	E						E				
Specified DFT Range	mils					Specified DFT Range	mils				
DFT Range Achieved	mils					DFT Range Achieved	mils				
Item / Area Description	Spot Meas	Readings			Avg	Item / Area Description	Spot Meas	Readings			Avg
		1	2	3				1	2	3	
	A						A				
	B						B				
	C						C				
	D						D				
	E						E				
Specified DFT Range	mils					Specified DFT Range	mils				
DFT Range Achieved	mils					DFT Range Achieved	mils				

Note: Complete a separate report for change in Coating Material, Application Method, or Batch.

MPLX	Tank Coating Packet	ENG-STD-0006-FOR-02	
	Form	Page 7 of 7	
		DATE: 4/1/2021	Rev: 0

Holiday Testing

Project Information

Project Name / AFE #	
Location of Work	
Tank Description	

Dry Film Thickness

Inspector & NACE Certification #	
Inspection Tool / Serial #	
Calibration Tool / Serial #	
Comments	

Date	Location	Surface Area (Sq Ft)	Voltage	Repairs	Comments

MPLX	Coating Variance Request	ENG-STD-0006-FOR-03	
	Form	Page 1 of 2	
		DATE: 4/1/2021	Rev: 0

Project / Maintenance Item				
Properties		MPLX Specified Product(s)	Proposed Product(s)	
Name				
Chemical Type				
Percent Solids by Volume				
VOCs (g/L)				
Coverage per Gallon at 1 mil DFT (ft^2)				
DFT per Coat (mils)				
Number of Coats Required				
SSPC Surface Preparation				
Colors				
Finish				
Max Pot Life Time at 75°F				
Min/Max Dry to Recoat or Topcoat Time at 75°F				
Min Cure Time at 75°F				
Min/Max Application Temperature (°F)				
Max Service Temperature (°F)				
Adhesion (psi), ASTM D4541				
Abrasion Resistance (mg), ASTM D4060 (1000 cycles/CS-17 wheel/1 kg load)				
Cathodic Disbondment (mm), ASTM G95 (28 days at 77°F)				
Compatibility (Internal Only)				
Crude Service				
Refined Fuels				
Ethanol				
Acids				
Alkalines				
Strong Solvent				
Potable Water				
Waste Water				
Approval	Name	Title	Signature	Date

* Any substitution or variation must be approved by MPLX's Regional Corrosion Control Team Lead or Engineer before the start of work. The Contractor shall submit the MPLX Coating Variance Request Form, along with the SDS and technical datasheets, for the proposed substitution.

	Coating Variance Request	ENG-STD-0006-FOR-03	
	Form	Page 2 of 2	
		DATE: 4/1/2021	Rev: 0

Remarks

* Any substitution or variation must be approved by MPLX's Regional Corrosion Control Team Lead, or Engineer before the start of work. The Contractor shall submit the MPLX Coating Variance Request Form, along with the SDS and technical datasheets, for the proposed substitution.

	Engineering Standard	ENG-STD-0007	
	Internal Tank Linings	Page 1 of 9	
		DATE: 4/1/2021	Rev: 0

Contents

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This standard provides requirements for internal tank lining applications so as to provide:

- Compliance with regulatory requirements (for Breakout tanks).
- The intended service life of the pertinent tank and tank lining.
- Standardization of work procedures, materials, color schemes, and inspection requirements.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- ENG-STD-0006-FOR-02 Tank Coating Packet
- ENG-STD-0006-FOR-03 Coating Variance Request Form

2.2 Industry Codes and Standards

Steel Structures Painting Council (SSPC)

- SSPC AB-1 Mineral and Slag Abrasives
- SSPC PA-1 Shop, Field and Maintenance Coating
- SSPC SP-10 Near-White Blast Cleaning

American Petroleum Institute (API)

- API RP 652-2005 Linings of Aboveground Petroleum Storage Tank Bottoms

2.3 Government Regulations

- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Anchor Profile	The profile of minute projections formed on a metal surface by sandblasting, shot blasting, or chemical etching; used to enhance the adhesiveness of a surface coating.
Contractor	Company or business that agrees to furnish linings or perform specified services at a specified price and/or rate to the MPLX.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Curing	Setting up or hardening, generally due to a polymerization reaction between two or more chemicals (resin and curative).
Dew Point	Temperature at which moisture will condense on the surface.
Forced-Curing	Acceleration of curing by increasing the temperature above ambient, accompanied by forced air circulation.
Holiday	A discontinuity of lining that exposes the metal surface to the environment.
Inspector/ Person in Charge (PIC)	An MPLX appointed engineer or inspector.
Lining	An internal barrier.
Manufacturer	The recipient of a direct or indirect purchase order for materials and/or equipment. In this context, a direct order is one issued to a manufacturer by a contractor or MPLX. An indirect order is one issued to a manufacturer by a vendor (recipient of a direct order) for materials, fabricated components, or subassemblies.
Mil	One one-thousandth of an inch (0.001”).
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.

4.0 REQUIREMENTS

4.1 Internal tank linings shall be installed in accordance with API 652.

4.2 All MPLX Tank Linings meet the requirements for containing:

- Crude up to 140°F
- Ethanol (with the exception of Plasite 4500FS)
- Refined Products
- Biofuels up to 120°F
- Marine Diesel up to 140°F

4.3 For lining selection for products not covered in Section 4.2, contact the Regional Corrosion Control Team Lead or Engineer.

4.4 The lining inspector shall, at a minimum, be NACE Coating Inspector Level I Certified.

4.5 Since the linings used are combined at the job site to create a new material, the lining, it is imperative that the ingredients be properly handled, mixed and applied in accordance with the manufacturer's requirements. The manufacturer of the material components shall supply a written procedure for the application of the lining system and related SDSs (Safety Data Sheets).

4.6 The Manufacturer of the lining system and application contractor shall provide a written five-year warranty for thin film linings and a written ten-year warranty for thick film linings.

4.7 All linings shall be delivered to the jobsite in original, unopened containers, with the product name and batch number of the Manufacturer. The containers shall remain unopened and stored properly from the elements.

4.8 All linings shall be from the same Manufacturer and shall have a current expiration date that shall not be exceeded if the lining work is delayed by one month.

5.0 SURFACE PREPARATION

5.1 Surfaces shall be prepared and cleaned in accordance with SSPC SP-1 and the SSPC specifications indicated Appendix A "Table 3 – Internal Tank Lining Systems", and as indicated in the paint manufacturer's printed instructions specifying surface preparation for the lining system to be used.

5.2 Heating coils, piping, and equipment not in the scope of work, shall be properly covered prior to blasting to prevent residual product from contaminating the blasted surface from overblast and/or when a tank may have to be heated. The covering needs to be adequate to prevent damage and contamination to the object being covered.

5.3 All personnel walking on blast cleaned surfaces shall cover work boots properly as not to contaminate surface (example – poly boots). Rags are not considered acceptable foot protection.

5.4 Abrasive blasting shall not be performed if the steel surface temperature is less than 5°F above the dew point or if the relative humidity is greater than 80%. If the prepared surface is degraded or contaminated subsequent to surface preparation and prior to lining application, the surface shall be restored to the specified cleanliness. See Appendix B "Table 4 - Dew Point Calculation Chart" to determine dew point relative to ambient air temperature and humidity.

5.5 The abrasive media used in blast cleaning shall meet SSPC AB-1 requirements.

5.6 For tanks previously in service, all surfaces shall be tested for soluble salts and decontaminated, as deemed necessary, per the lining manufacturer's specification.

5.7 All surfaces prepared for lining are to be inspected and shall be accepted as satisfactory by the Inspector/PIC before any lining is applied by the Contractor. Contractors shall also inspect all surfaces after cleaning and shall notify the Inspector/PIC of any defects, improper material, poor workmanship or other conditions, which, in his opinion, will affect the satisfactory performance and permanency of his work. Where such defects have been discovered, no lining shall be started until all faulty conditions have been corrected or until a written agreement has been made with the Inspector/PIC regarding any subsequent defects that may develop because of the condition noted.

5.8 Cleaning and lining shall be scheduled whereby the dust and contaminants from the cleaning process or the manufacturing operation shall not fall on newly coated surfaces.

6.0 LINING MATERIALS

6.1 Only the products listed in Appendix A "Table 3 – Internal Tank Lining Systems" shall be used, unless approved by the Regional Corrosion Control Team Lead or Engineer.

6.2 Any deviations from the products listed in Appendix A "Table 3 – Internal Tank Lining Systems" shall be accompanied with a completed and signed copy of the ENG-STD-0006-FOR-03 "Coating Variance Request Form".

7.0 APPLICATION

7.1 All work shall be performed in accordance with SSPC PA-1 "Shop, Field and Maintenance Coating", the coating manufacturer's recommendations and this Standard.

7.2 The lining shall be applied in strict accordance with the Manufacturer's specifications and the additional requirements listed here.

7.3 The minimum surface temperature specified by the lining Manufacturer shall be maintained during the lining application and curing process.

7.4 If heating is required, the following shall apply:

- ➢ Only indirect-fired heaters shall be used in both the heating and curing operations.
- ➢ Heaters are required to be pre-approved by MPLX.

7.5 All welds, irregular surfaces, pitted areas, and any surfaces that have been ground down shall be brush striped prior to application of prime coat.

7.6 Contrasting colors shall be used between coats.

7.7 All linings shall be power mixed.

7.8 The dry film thickness of each coat and of the entire system shall meet the requirements for both the number of coats and minimum and maximum dry film thickness recommended by the Manufacturer.

7.9 The applicator shall have proper equipment (example: wet film gauge/dry film gauge) to check the minimum and maximum conditions of the manufacturer's specification. Dry film gauges shall be properly calibrated prior to every use.

7.10 All applied linings shall be free of runs, sags, embedded foreign matter and any other indication of improper application procedure.

7.11 Surface contamination, as determined by the Inspector/PIC, that develops between coats shall be removed by the proper cleaning method as determined by the Inspector.

7.12 The Inspector/PIC shall have the right to reject all work that does not conform to the specifications identified with this Standard.

7.13 Inspection by the MPLX or his representative or MPLX's failure to provide inspection over a period of time shall not relieve the Contractor of his responsibilities to provide linings and work that conform to the specifications.

7.14 All tanks with internal linings shall have the following, in letters a minimum of 3" high, stenciled every 90° around the exterior of the tank shell: "Internal Lining – Do Not Weld." Clarification as to the extent of the lining can then be established.

7.15 The air, surface, and lining temperature at the time of application shall be at a minimum temperature of 50°F, unless specified by Manufacturer, and 5°F above dew point. See Appendix B "Table 4 - Dew Point Calculation Chart" to determine dew point relative to ambient air temperature and humidity.

8.0 INSPECTION

8.1 All lined surfaces shall first be visually inspected, followed by inspection with an approved holiday detector, unless a different inspection approach is approved by the Regional Corrosion Team Lead or Engineer. All holidays and areas of damaged lining shall be repaired using compatible system/material(s) immediately after detection. All lining repairs shall be inspected after repair lining system has cured sufficiently to prevent damage.

CAUTION: *Holiday voltages shall be adequate in accordance with lining manufacturer's specifications but shall not exceed lining manufacturer's specifications. Exceeding lining manufacturer's recommendations can damage the lining and cause premature failures.*

8.2 For holiday detectors with built-in metering ability, the unit's readout voltage shall be recorded in open circuit (HV) and shorted (ground to coil) state at the start of each coating inspection effort.

8.3 For High Voltage (>100 V) holiday detectors without built-in metering, the holiday detector shall be calibrated using the manufacturer's recommended calibration tool at the start of each coating inspection effort.

8.4 For Low Voltage (≤100 V) holiday detectors without built-in metering, the holiday detector shall be calibrated using the manufacturer's recommended calibration tool, or a calibrated digital multimeter in "DC Volts" mode, at the start of each coating inspection effort.

8.5 All holiday detectors shall be calibrated annually by the manufacturer.

8.6 The inspection times and voltage readings shall be recorded as part of the lining inspection documentation process.

8.7 The holiday detector brush, and/or other contact devices shall contact the entire lined surface.

8.8 The lining contractor shall permit inspection of all phases of work by the Inspector/PIC such as:

- Atmospheric conditions, such as temperature, humidity, dew point
- Surface preparation equipment
- Steel surfaces prior to surface preparation
- Steel surfaces following cleaning and surface preparation
- Lining application equipment
- Lining material containers and ID labels
- Lining application process
- Lining quality and thickness, wet and dry

8.9 The Inspector/PIC shall, for each item coated, determine and record the information requested on ENG-STD-0006-FOR-02 "Tank Coating Packet". The contractor representative shall maintain this record if the Inspector/PIC is not present.

APPENDIX A INTERNAL TANK LINING SYSTEMS

Table 2 Internal Tank Lining Systems

System No	Application	Service Temperature	Ambient Application Temperature	Surface Prep, SSPC SP	Anchor Profile, Mils	Product
TL-1	Plural Spray Applied System	Product Dependent	Between 35°F and 90°F	SP-10	Min. 3.0	Carboline Plasite 4550 (NE) **Total DFT:** 25 Mils **Color(s):** Light Gray Tile Red White
TL-2	Plural Spray Applied System	Product Dependent	Between 20°F and 100°F	SP-10	Min. 3.0	Carboline Plasite 4500FS (EP) **Total DFT:** 25 Mils **Color(s):** Light Gray Light Blue White
TL-3	Single-Leg Airless Applied System	Product Dependent	Between 35°F and 110°F	SP-10	Min. 3.0	Carboline Phenoline Tank Shield Series (EP) **Total DFT:** 12 to 40 Mils **Color(s):** Gray Blue White
TL-4	Single-Leg Airless Applied System	Product Dependent	Between 45°F and 120°F	SP-10	3.0 - 4.0	Sherwin Williams Nova-Plate 360 (NE) **Total DFT:** 15 to 35 Mils **Color(s):** Blue Green
TL-5	Single-Leg Airless Applied System	Product Dependent	Between 40°F to 110°F	SP-10	2.0 – 3.0	Sherwin Williams Dura-Plate UHS (EP) **Total DFT:** 18 to 22 Mils **Color(s):** Light Gray White Light Green
TL-6	Single-Leg Airless Applied System	Product Dependent	Between 35°F to 120°F	SP-10	2.0 – 3.0	Sherwin Williams Phenicon HS (NE) **Total DFT:** 5 to 7 Mils **Color(s):** Off White Light Gray Light Blue

Type Codes:

NE	Novolac Epoxy
PE	Phenolic Epoxy
EP	Epoxy

APPENDIX B DEW POINT CALCULATION CHART

Table 3 Dew Point Calculation Chart

Ambient Air Temperature °F		20	30	40	50	60	70	80	90	100	110	120
% Relative Humidity	90	18	28	37	47	57	210	77	87	97	107	117
	85	17	26	36	45	55	65	75	84	95	104	113
	80	16	25	34	44	54	63	73	82	98	102	110
	75	15	24	33	42	52	62	71	80	91	100	108
	70	13	23	31	40	50	60	68	78	88	96	105
	65	12	20	29	38	47	57	66	76	85	93	103
	60	11	19	27	36	45	55	64	73	83	92	101
	55	9	17	25	34	43	53	61	70	80	89	98
	50	6	15	23	31	40	50	59	67	77	86	94
	45	4	13	21	29	37	47	56	64	73	82	91
	40	1	11	18	26	35	43	52	61	69	78	87
	35	-2	8	16	23	31	40	48	57	65	74	83
	30	-6	4	13	20	28	36	44	52	61	69	77

	Engineering Standard	ENG-STD-0008
MPLX	Coating of Underground Pipe	Page 1 of 11
		DATE: 4/1/2021 — Rev: 0

Contents

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for surface preparation and coating application on field welds, replacement pipe, tie-in connections, and reconditioning of coating or wrapping on underground pipe to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities)
- The intended coating service life for the asset.
- Standardization of work procedures, materials, color schemes, and inspection requirements as they pertain to field coating.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

Excluded from this Standard are air-to-soil transition areas and aboveground piping.

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- ENG-STD-0006-FOR-01 Pipeline Coating Packet
- ENG-STD-0006-FOR-03 Coating Variance Request Form
- ENG-STD-0010 Plant Applied Coating Specification

2.2 Industry Codes and Standards

Steel Structures Painting Council (SSPC)

- SSPC AB-1 Mineral and Slag Abrasives
- SSPC PA-1 Shop, Field and Maintenance Coating
- SSPC SP-2 Hand Tool Cleaning
- SSPC SP-3 Power Tool Cleaning
- SSPC SP-7 Brush-Off Blast Cleaning
- SSPC SP-10 Near-White Blast Cleaning

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Anchor Profile	The profile of minute projections formed on a metal surface by sandblasting, shot blasting, or chemical etching; used to enhance the adhesiveness of a surface coating.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Contractor	Company or business that agrees to furnish materials or perform specified services at a specified price and/or rate to MPLX.
Dew Point	Temperature at which moisture will condense on the surface.
Flocking	Field applied fusion bonded epoxy for girth welds and fittings
Holiday	A discontinuity of coating that exposes the metal surface to the environment.
Inspector/ Person in Charge (PIC)	An MPLX appointed engineer or inspector.
Lining	An internal barrier.
Manufacturer	The recipient of a direct or indirect purchase order for materials and/or equipment. In this context, a direct order is one issued to a manufacturer by a contractor or MPLX. An indirect order is one issued to a manufacturer by a vendor (recipient of a direct order) for materials, fabricated components, or subassemblies.

Table 1 Definitions

Term	Description
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.

4.0 GENERAL REQUIREMENTS

4.1 Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is constructed, relocated, replaced, or otherwise changed after March 31, 1970.

4.2 The coating systems prescribed in this Standard were selected based on their ability to do the following:

1. Mitigate corrosion of underground pipe.
2. Satisfactorily adhere to the metal surface.
3. Prevent migration and accumulation of moisture at the metal surface.
4. Resist cracking and damage due to handling and soil stress.
5. Support cathodic protection.

If insulating-type coatings are required for underground pipe, contact the Corrosion Control Program Manager.

4.3 All below ground tape wrap shall be non-shielding.

4.4 The coating inspector shall, at a minimum, be NACE Coating Inspector Level I Certified.

5.0 SURFACE PREPARATION

5.1 The pipe coating cutback for external line-up clamp clearance at girth welds shall be 5 ± 1/4 inch from the center of the weld.

5.2 Outer wrap (Kraft, film, felt, etc.) and protective wrap (rock protection), if present, shall be removed for a distance of 3 inches back from the edge of the coating cutback.

5.3 Surfaces shall be prepared and cleaned in accordance with the SSPC specifications indicated in the Coating Schedule, and as indicated in the coating manufacturer's printed instructions specifying surface preparation for the coating system to be used.

5.4 Where SSPC SP-1, SSPC SP-2, or SSPC SP-3 is indicated for metal surfaces, it means that the surface shall be clean, dry, and free of dirt, dust, oils, or any contamination that would adversely affect the adhesion or appearance of the coating.

5.5 Hand and power tool cleaning shall be conducted so as to remove burrs, weld spatter, shape edges and other irregularities, but to minimize polishing or burnishing of the prepared surface.

5.6 Abrasive blasting shall not be performed if the steel surface temperature is less than 5°F above the dew point or if the relative humidity is greater than 80%. If the prepared surface is degraded or contaminated subsequent to surface preparation and prior to paint application, the surface shall be restored to the specified cleanliness. See Appendix B "Table 4 - Dew Point Calculation Chart" to determine dew point relative to ambient air temperature and humidity.

5.7 The abrasive media used in blast cleaning shall meet SSPC AB-1 requirements.

5.8 Studies have shown that coating over abrasive blasted steel has lasted up to three times as long as wire brushed steel. Various abrasives can be selected to produce varying degrees of anchor patterns. Some of the more common ones are Black Beauty and VitroGrit, see Table 2.

Table 2 Common Abrasives

Anchor Profile	Products
1.0 mil	Black Beauty 3060 - X-Fine Grade
1.5 mil	Black Beauty 3060 - X-Fine Grade
2.0 mil	Black Beauty 2040 - Fine Grade
2.5 mil	Black Beauty 2040 - Fine Grade
3-4 mil	Black Beauty 1240 - Medium Grade
1.5+ mil	VitroGrit #70 - Super Fine
1.5 - 2.5 mil	VitroGrit #50 - Fine
2.5 - 3.5 mil	VitroGrit #30/50 - Medium/Fine
3.0 - 4.0 mil	VitroGrit #16/30 - Coarse/Medium

6.0 COATING MATERIALS

6.1 Only the products listed in Appendix A "Table 3 - Coating Systems for Underground Pipe" shall be used, unless approved by the Regional Corrosion Control Team Lead or Engineer.

6.1.1 For coating repairs that are performed during integrity digs, only tape coating systems (PC-22 through PC-26) shall be used unless a surface profile can be obtained using abrasive blasting or a Montipower Bristle Blaster that will allow for the use of a liquid coating.

6.1.2 Fusion Bonded Epoxy coating systems (PC-1 through PC-4) are covered in ENG-STD-0010.

6.1.3 Cable-to-pipe connections can also be coated using one of the following approved patch kits:

- Trenton Patch-Pad
- Royston Handy Cap
- Thermoweld ThermOcap
- Amcorr Viscotaq Welding Patch

6.2 Any deviations from the products listed in Appendix A "Table 3 - Coating Systems for Underground Pipe" shall be accompanied with a completed and signed copy of the ENG-STD-0006-FOR-03 "Coating Variance Request Form".

7.0 APPLICATION

7.1 All work shall be performed in accordance with SSPC PA-1 "Shop, Field and Maintenance Coating", the coating manufacturer's recommendations and this Standard.

7.2 All materials shall be applied in smooth, even coats without runs, sags, or bare spots. Dry film thickness where indicated in Appendix A "Table 3 - Coating Systems for Underground Pipe" is the minimum required.

7.3 Tape coating shall not be applied onto the protective wraps and/or outer wraps, only to bare steel or primed pipe coating, as required by the coating manufacturer.

7.4 A wrapping machine shall be used any time tape that is greater than 4 inches wide is being applied or the exposed area is greater than 5 feet long. When required, use an approved hand wrapping machine, such as:

- Tapecoat's Hand Wrapster No. 3
- Stuart Wrapster Model CCW9, CS4, 6, or 9
- Encoat's (formerly Gaido-Lingle) E-ZEE-WRAP

7.5 Tape coating shall be wrapped using the spiral wrap method. The cigarette wrap method shall not be used. The exposed sidewall of the tape shall face 'down' such that moisture or other contaminants are not entrapped.

7.6 Do not expose the tape-wrapped pipe to any hydrocarbon or other damaging fluid contaminated soils.

7.7 The air, surface, and coating temperature at the time of application shall be at a minimum temperature of 50°F, unless specified by Manufacturer, and 5°F above dew point. If construction completion occurs during unsuitable weather, it is not detrimental to leave the steel uncoated until weather conditions are suitable for coating given that the steel remains exposed and is not buried during this time. See Appendix B "Table 4 - Dew Point Calculation Chart" to determine dew point relative to ambient air temperature and humidity.

7.8 Flocking is an acceptable method to apply fusion bonded epoxy to girth welds and fittings in the field.

8.0 INSPECTION

8.1 General

8.1.1 All externally coated pipe must be inspected just prior to lowering the pipe into the ditch or submerging the pipe. All coated pipe, including field joints, shall first be visually inspected, followed by inspection with an approved holiday detector, unless a different inspection approach is approved by the Regional Corrosion Control Team Lead or Engineer. All holidays and areas of damaged coating shall be repaired using compatible system/material(s) immediately after detection. All coating repairs shall be inspected after repair coating system has cured sufficiently to prevent damage.

CAUTION: *Holiday voltages shall be adequate in accordance with coating manufacturer's specifications but shall not exceed coating manufacturer's specifications. Exceeding coating manufacturer's recommendations can damage the coating and cause premature failures.*

8.1.2 For holiday detectors with built-in metering ability, the unit's readout voltage shall be recorded in open circuit (HV) and shorted (ground to coil) state at the start of each coating inspection effort.

8.1.3 For High Voltage (>100 V) holiday detectors without built-in metering, the holiday detector shall be calibrated using the manufacturer's recommended calibration tool at the start of each coating inspection effort.

8.1.4 For Low Voltage (≤100 V) holiday detectors without built-in metering, the holiday detector shall be calibrated using the manufacturer's recommended calibration tool, or a calibrated digital multimeter in "DC Volts" mode, at the start of each coating inspection effort.

8.1.5 All holiday detectors shall be calibrated annually by the manufacturer.

8.1.6 The inspection times and voltage readings shall be recorded as part of the coating inspection documentation process.

8.1.7 The holiday detector coil, brush, and/or other contact devices shall contact the entire coated pipe surface.

8.1.8 The coating contractor shall permit inspection of all phases of work by an authorized MPLX Representative such as:

- Atmospheric conditions, such as temperature, humidity, dew point
- Surface preparation equipment
- Steel surfaces prior to surface preparation
- Steel surfaces following cleaning and surface preparation
- Coating application equipment
- Coating material containers and ID labels
- Coating application process
- Coating film quality and thickness, wet and dry

8.1.9 The Inspector/PIC shall, for each item coated, determine and record the information requested on ENG-STD-0006-FOR-01 "Pipeline Coating Packet". The contractor representative shall maintain this record if the Inspector/PIC is not present.

8.2 Epoxy Coating Systems

8.2.1 Bubbles, excessive runs, drips, and foreign matter shall not be present. Coating shall be adequately cured before coated object is handled or backfilled.

8.2.2 Wet and dry film thickness and hardness shall be in accordance with manufacturer's specifications. As a minimum, the dry film thickness (DFT) shall be checked in each case with an acceptable nondestructive DFT gauge and the results shall be recorded as part of the coating inspection documentation process.

8.3 Tape Coating Systems

8.3.1 Bubbles or wrinkles shall not be present. Overlap and proper tension shall be in accordance with manufacturer's specifications.

APPENDIX A COATING SYSTEMS FOR UNDERGROUND PIPE AREAS

Table 3 Coating Systems for Underground Pipe

Environment	System No	Category Item	Service Temperature	Ambient Application Temperature	Surface Prep, SSPC SP	Anchor Profile, Mils	Product
Underground steel piping, valves and fittings and bore pipe	PC-5	"Abrasion Resistant Overlay" Applied Over	Up to 140°F	Between -20°F and 120°F	SP-10 (Bare Steel) SP-7 (FBE Coated)	3.0 – 4.0 (Bare Steel) Min. 2.0 (FBE Coated)	Powercrete J ARO (ARO) Total DFT: 20 Mils Typ. Color: Brown
Underground steel piping, valves and fittings	PC-8	Touch Up of Girth Welds, Fitting/Valves, Soil/Air Interface, Dig Outs/Rehab	Up to 200°F	Between 20°F and 110°F	SP-10	2.5 - 4.5	Polyclad 975 (EPC) Total DFT: 20 to 50 mils Color: Multi
Underground steel piping, valves and fittings	PC-9	Where surface preparation tolerance is needed	Contact Manufacturer	Between 40°F and 200°F	SP-10	1.5 - 4.0	3M Scotchkote 323 (EPC) Total DFT: 25 to 60 mils. Color: Blue-Green
Underground steel piping, valves and fittings	PC-10	Where surface preparation tolerance is needed	Up to 200°F	Down to 50°F	SP-10	2.5 - 4.5	3M Scotchkote 327 (EPC) Total DFT: 25 mils Min. Color: Blue-Green
Underground steel piping, valves, and fittings and bore pipe	PC-11	Cold Temperature Application	Between -40°F and 150°F	Between -4°F and 68°F	SP-10	2.5 - 5.0	Denso Protal 7125 (EPC) Total DFT: 25 to 30 mils Color: White
Underground steel piping, valves, and fittings and bore pipe	PC-12	Where surface preparation tolerance is needed	Between -40°F and 203°F	Down to 50°F	SP-10	2.5 - 5.0	Denso Protal 7200 (EPC) Total DFT: 25 to 30 mils Color: Green
Underground steel piping, valves, and fittings	PC-13	Damp Surfaces	Between 41°F and 150°F	Between 41°F and 150°F	SP-10	2.5 - 5.0	Denso Protal 7300 (EPC) Total DFT: 30 to 60 mils Color: Gray

Table 3 Coating Systems for Underground Pipe

Environment	System No	Category Item	Service Temperature	Ambient Application Temperature	Surface Prep, SSPC SP	Anchor Profile, Mils	Product
Underground steel piping, valves, and fittings	PC-14	High Service Temperature	Up to 250°F, with peeks to 300°F	Down to 50°F	SP-10	2.5 - 5.0	Denso Protal 7900HT (EPC) Total DFT: 30 to 60 mils Color: Gray
Underground steel piping, valves, and fittings	PC-15	Where surface preparation tolerance is needed	Up to 175°F	Between 50°F and 175°F	SP-10	2.5 - 5.0	Polyguard NHT-5600 (EPC) Total DFT: 25 to 30 mils Color: Blue
Underground steel piping, valves, and fittings	PC-16	High Service Temperature	Up to 350°F	Between 50°F and 185°F	SP-10	2.5 - 5.0	Polyguard NHT-6100 (EPC) Total DFT: 30 to 60 mils Color: Orange
Underground steel piping, valves and fittings	PC-17	Minimal Surface Preparation	Up to 149°F	Between -22°F and 221°F	SP-11	1.0 – 1.5	SPC-1288 (EPC) Total DFT: 20 to 50 mils Color: Blue
Underground steel piping, valves, and fittings	PC-18	Where surface preparation tolerance is needed	Up to 176°F	Between -40°F and 122°F	SP-10	2.5 - 5.0	SPC-2888 (EPC) Total DFT: 20 to 50 mils Color: Blue
Underground steel piping, valves, and fittings	PC-19	Where surface preparation tolerance is needed	Up to 203°F	Between -13°F and 212°F	SP-10	2.5 - 5.0	SPC-3888 (EPC) Total DFT: 20 to 50 mils Color: Red
Underground steel piping, valves, and fittings	PC-20	Damp Surface	Up to 176°F	Down to 41°F	SP-10	2.5 - 5.0	SPC-4888 (EPC) Total DFT: 30 to 50 Mils Color: Brown

Table 3 Coating Systems for Underground Pipe

Environment	System No	Category Item	Service Temperature	Ambient Application Temperature	Surface Prep, SSPC SP	Anchor Profile, Mils	Product
Underground steel piping, valves, and fittings	PC-21	High Service Temperature	Up to 302°F	Between -40°F and 122°F	SP-10	2.5 - 5.0	SPC-8888 (EPC) Total DFT: 30 to 60 mils Color: Red
Underground steel piping, valves and fittings	PC-22	Where surface preparation tolerance is needed	Between -43°F and 160°F	Down to 37°F (substrate temperature)	SP-3	-	Viscowrap – ST (VTW) Color: Blue
			Between -31°F and 212°F	Down to 37°F (substrate temperature)	SP-3	-	Viscowrap – HT (VTW) Color: Blue
		Flange Filling Paste	Between -43°F and 176°F	Down to 68°F (substrate temperature)	SP-3	-	Viscopaste (PST) Color: Blue
		UV Mechanical Protection (Required for Aboveground Viscowrap)	Up to 185°F	Down to 41°F (substrate temperature)	-	-	PE Outerwrap (TW) Color: Black
		UV Mechanical Protection (Required for Aboveground Viscowrap)	Up to 185°F	Down to 41°F (substrate temperature)	-	-	PVC Outerwrap (TW) Color: Black
Underground steel piping, valves and fittings	PC-23	Piping, Valves, Pumps, Difficult to Protect Areas. Below Ground Use (Primer Required)	Between -50°F and 120°F	Between 0°F and 100°F	SP-2	-	Trenton Wax Tape #1 (TW) Color: Brown
Underground steel piping, valves and fittings	PC-24	Below and Above Ground Use (Primer Required)	Between -50°F and 120°F	Between 0°F and 100°F	SP-2	-	Trenton Wax Tape #2 (TW) Color: White
Underground steel piping, valves and fittings	PC-25	Below Ground Use (Primer Required). Outerwrap Optional if Soil Stress will be Encountered (SP-6)	Up to 145°F	Down to 45°F	SP-3	-	Polyguard RD-6 (TW) Color: Black

Table 3 Coating Systems for Underground Pipe

Environment	System No	Category Item	Service Temperature	Ambient Application Temperature	Surface Prep, SSPC SP	Anchor Profile, Mils	Product
Underground steel piping, valves and fittings	PC-26	Below and Above Ground Use	Between -20°F and 140°F	-	-	-	Chase Corporation Tapecoat H50 Gray (TW) Color: Gray
Underground new factory coated steel piping installations	PC-27	Impact Resistant Outerwrap for Bores	Up to 150°F	Contact Manufacturer	Abrade coating	-	Polyguard IRO (CW) Color: Gray

Type Codes:

ARO	Abrasion Resistance Overlay
EPC	Epoxy Pipeline Coating
TW	Tape Wrap
PST	Paste
VTW	Viscoelastic Tape Wrap
CW	Composite Wrap

APPENDIX B DEW POINT CALCULATION CHARTS

Table 4 Dew Point Calculation Charts

Ambient Air Temperature °F		20	30	40	50	60	70	80	90	100	110	120
% Relative Humidity	90	18	28	37	47	57	210	77	87	97	107	117
	85	17	26	36	45	55	65	75	84	95	104	113
	80	16	25	34	44	54	63	73	82	98	102	110
	75	15	24	33	42	52	62	71	80	91	100	108
	70	13	23	31	40	50	60	68	78	88	96	105
	65	12	20	29	38	47	57	66	76	85	93	103
	60	11	19	27	36	45	55	64	73	83	92	101
	55	9	17	25	34	43	53	61	70	80	89	98
	50	6	15	23	31	40	50	59	67	77	86	94
	45	4	13	21	29	37	47	56	64	73	82	91
	40	1	11	18	26	35	43	52	61	69	78	87
	35	-2	8	16	23	31	40	48	57	65	74	83
	30	-6	4	13	20	28	36	44	52	61	69	77

	Engineering Standard	ENG-STD-0009	
MPLX	Coating of Transition Areas	Page 1 of 12	
		DATE: 4/1/2021	Rev: 0

Contents

List of Figures

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This standard provides requirements for surface preparation and coating applications on piping at new and existing soil-air transition areas so as to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended coating service life for the asset.
- Standardization of work procedures, materials, color schemes, and inspection requirements as they pertain to field coating.

Revision:	Prepared by:	Approved by:	Issue Date:
2	Ryan Ell		

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

1.2.2 In addition to soil-air transition areas, this Standard is also applicable to pipeline spans and/or sections that may be temporarily submerged (under water) or buried (under debris or soil), due to run-off or other flowing water conditions.

2.0 REFERENCES

2.1 Marathon Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- ENG-STD-0006-FOR-01 Pipeline Coating Packet
- ENG-STD-0006-FOR-03 Coating Variance Request Form

2.2 Industry Codes and Standards

Steel Structures Coating Council (SSPC)

- SSPC AB-1 Mineral and Slag Abrasives
- SSPC PA-1 Shop, Field and Maintenance Coating
- SSPC SP-2 Hand Tool Cleaning
- SSPC SP-3 Power Tool Cleaning
- SSPC SP-10 Near-White Blast Cleaning
- SSPC SP-11 Power Tool Clean to Bare Metal

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	**Description**
Anchor Profile	The profile of minute projections formed on a metal surface by sandblasting, shot blasting, or chemical etching; used to enhance the adhesiveness of a surface coating.
Cathodic Protection	A technique to control corrosion of a metal surface by making it the cathode in an electrochemical cell.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Contractor	Company or business that agrees to furnish materials or perform specified services at a specified price and/or rate to the Marathon.
Curing	Setting up or hardening, generally due to a polymerization reaction between two or more chemicals (rein and curative).
Dew Point	Temperature at which moisture will condense on the surface.
Inspector/ Person in Charge (PIC)	A Marathon appointed engineer or inspector.
Manufacturer	The recipient of a direct or indirect purchase order for materials and/or equipment. In this context, a direct order is one issued to a manufacturer by a contractor or the Marathon. An indirect order is one issued to a manufacturer by a vendor (recipient of a direct order) for materials, fabricated components, or subassemblies.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.

4.0 REQUIREMENTS

4.1 Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is constructed, relocated, replaced, or otherwise changed after March 31, 1970.

4.2 Existing coating at a transition area that display both good adhesion to the pipe surface and no porosity does not need to be removed and replaced. When existing transition area coatings are left in place, they shall be over-wrapped to fully encapsulate and seal the existing coating though.

4.3 The coating inspector shall, at a minimum, be NACE Coating Inspector Level I Certified.

5.0 SURFACE PREPARATION

5.1 On existing transition piping that is showing signs of potential corrosion, in order to ensure that excessive corrosion pitting is not present wherein the pipe wall might be weakened with "hard cleaning" techniques, the metal surfaces shall be "soft cleaned" or "brushoff blasted" to more carefully expose any potentially significant corrosion areas.

5.2 Surfaces shall be prepared and cleaned in accordance with the SSPC specifications indicated in the Coating Schedule, and as indicated in the coating manufacturer's printed instructions specifying surface preparation for the coating system to be used.

5.3 Where SSPC SP-1, SSPC SP-2, or SSPC SP-3 is indicated for metal surfaces, it means that the surface shall be clean, dry, and free of dirt, dust, oils, or any contamination that would adversely affect the adhesion or appearance of the coating.

5.4 Hand and power tool cleaning shall be conducted so as to remove burrs, weld spatter, shape edges and other irregularities, but to minimize polishing or burnishing of the prepared surface.

5.5 Abrasive blasting shall not be performed if the steel surface temperature is less than 5°F above the dew point or if the relative humidity is greater than 80%. If the prepared surface is degraded or contaminated subsequent to surface preparation and prior to coat application, the surface shall be restored to the specified cleanliness. See Appendix B "Table 4 - Dew Point Calculation Chart" to determine dew point relative to ambient air temperature and humidity.

5.6 The abrasive media used in blast cleaning shall meet SSPC AB-1 requirements.

5.7 Studies have shown that coating over abrasive blasted steel has lasted up to three times as long as wire brushed steel. Various abrasives can be selected to produce varying degrees of anchor patterns. Some of the more common ones are Black Beauty and VitroGrit, see Table 2.

Table 2 Common Abrasives

Anchor Profile	Product
1.0 mil	Black Beauty 3060 - X-Fine Grade
1.5 mil	Black Beauty 3060 - X-Fine Grade
2.0 mil	Black Beauty 2040 - Fine Grade
2.5 mil	Black Beauty 2040 - Fine Grade
3-4 mil	Black Beauty 1240 - Medium Grade
1.5+ mil	VitroGrit #70 - Super Fine
1.5 - 2.5 mil	VitroGrit #50 - Fine
2.5 - 3.5 mil	VitroGrit #30/50 - Medium/Fine
3.0 - 4.0 mil	VitroGrit #16/30 - Coarse/Medium

5.8 Existing coatings away from the transition area shall be power or hand tool abraded such that adequate adherence of transition area primer coating can be achieved. Wipe all surfaces as completely dry as possible.

6.0 COATING MATERIALS

6.1 Only the products listed in Appendix A "Table 3 - Coating Systems for Transition Areas" shall be used, unless approved by the Regional Corrosion Control Team Lead or Engineer.

6.1.1 When using FBE or Coating Systems PC-11 through PC-13, apply a UV resistance topcoat per the manufacturer's recommendation, to aboveground surfaces at transition areas.

6.1.2 When using Coating System PC-14, contact the Regional Corrosion Control Team Lead or Engineer for a topcoat recommendation for the aboveground surfaces at transition areas.

6.2 Any deviations from the products listed in Appendix A "Table 3 - Coating Systems for Transition Areas" shall be accompanied with a completed and signed copy of the ENG-STD-0006-FOR-03 "Coating Variance Request Form".

7.0 APPLICATION

7.1 All work shall be performed in accordance with SSPC PA-1 "Shop, Field and Maintenance Coating", the coating manufacturer's recommendations and this Standard.

7.2 All materials shall be applied in smooth, even coats without runs, sags, or bare spots. Dry film thickness where indicated in Appendix A "Table 3 - Coating Systems for Transition Areas" is the minimum required.

7.3 Tape Coating shall not be applied over existing protective wraps and/or outer wraps, only to bare steel or over a primer coating, as required by the coating manufacturer (excluding the manufacturer's recommended overlap).

7.4 A wrapping machine shall be used any time tape that is greater than 4 inches wide is being applied or the exposed area is greater than 5 feet long. When required, use an approved hand wrapping machine, such as:

- Tapecoat's Hand Wrapster No. 3
- Stuart Wrapster Model CCW9, CS4, 6, or 9
- Encoat's (formerly Gaido-Lingle) E-ZEE-WRAP

7.5 Tape Coating shall be wrapped using the spiral wrap method. The cigarette wrap method shall not be used. The exposed sidewall of the tape shall face 'down' such that moisture or other contaminants are not entrapped.

7.6 Always start wrapping from the bottom of the transition to the top of the transition. The overlap will then on top of the previous wrap in the upper direction.

7.7 Do not expose the tape-wrapped pipe to any hydrocarbon or other damaging fluid contaminated soils.

7.8 The air, surface, and coating temperature at the time of application shall be at a minimum temperature of 50°F, unless specified by Manufacturer, and 5°F above dew point. If construction completion occurs during unsuitable weather, it is not detrimental to leave the steel uncoated until weather conditions are suitable for coating given that the steel remains exposed and is not buried during this time. See Appendix B "Table 4 - Dew Point Calculation Chart" to determine dew point relative to ambient air temperature and humidity.

7.9 During the period when newly applied coating or tape is setting up, the coating or tape is especially susceptible to damage from livestock. Special precautions may need to be taken to protect the coating or tape during this period.

8.0 INSPECTION

8.1 General

8.1.1 All externally coated pipe must be inspected just prior to lowering the pipe into the ditch or submerging the pipe. All coated pipe, including field joints, shall first be visually inspected, followed by inspection with an approved holiday detector, unless a different inspection approach is approved by the Regional Corrosion Control Team Lead or Engineer. All holidays and areas of damaged coating shall be repaired using compatible system/material(s) immediately after detection. All coating repairs shall be inspected after repair coating system has cured sufficiently to prevent damage.

CAUTION: *Holiday voltages shall be adequate in accordance with coating manufacturer's specifications but shall not exceed coating manufacturer's specifications. Exceeding coating manufacturer's recommendations can damage the coating and cause premature failures.*

8.1.2 For holiday detectors with built-in metering ability, the unit's readout voltage shall be recorded in open circuit (HV) and shorted (ground to coil) state at the start of each coating inspection effort.

8.1.3 For High Voltage (>100 V) holiday detectors without built-in metering, the holiday detector shall be calibrated using the manufacturer's recommended calibration tool at the start of each coating inspection effort.

8.1.4 For Low Voltage (≤100 V) holiday detectors without built-in metering, the holiday detector shall be calibrated using the manufacturer's recommended calibration tool, or a calibrated digital multimeter in "DC Volts" mode, at the start of each coating inspection effort.

8.1.5 All holiday detectors shall be calibrated annually by the manufacturer.

8.1.6 The inspection times and voltage readings shall be recorded as part of the coating inspection documentation process.

8.1.7 The holiday detector coil, brush, and/or other contact devices shall contact the entire coated pipe surface.

8.1.8 The coating contractor shall permit inspection of all phases of work by an authorized Marathon Representative such as:

- Atmospheric conditions, such as temperature, humidity, dew point
- Surface preparation equipment
- Steel surfaces prior to surface preparation
- Steel surfaces following cleaning and surface preparation
- Coating application equipment
- Coating material containers and ID labels
- Coating application process
- Coating film quality and thickness, wet and dry

8.1.9 The Inspector/PIC shall, for each item coated, determine and record the information requested on ENG-STD-0006-FOR-01 "Pipeline Coating Packet". The contractor representative shall maintain this record if the Inspector/PIC is not present.

8.2 Epoxy Coating Systems

8.2.1 Bubbles, excessive runs, drips, and foreign matter shall not be present. Coating shall be adequately cured before coated object is handled or backfilled.

8.2.2 Wet and dry film thickness and hardness shall be in accordance with manufacturer's specifications. As a minimum, the dry film thickness (DFT) shall be checked in each case with an acceptable nondestructive DFT gauge and the results shall be recorded as part of the coating inspection documentation process.

8.3 Tape Coating Systems

8.3.1 Bubbles or wrinkles shall not be present. Overlap and proper tension shall be in accordance with manufacturer's specifications.

APPENDIX A COATING SYSTEMS FOR TRANSITION AREAS

Table 3 Coating Systems for Transition Areas

Environment	System No	Category Item	Service Temperature	Ambient Application Temperature	Surface Prep, SSPC-SP	Anchor Profile, Mils	Product
Underground steel piping, valves, and fittings and bore pipe	PC-11	Cold Temperature Application	Between -40°F and 150°F	Between -4°F and 68°F	SP-10	2.5 - 5.0	Denso Protal 7125 (EPC) Total DFT: 25 to 30 mils Color: White
Underground steel piping, valves, and fittings and bore pipe	PC-12	Where surface preparation tolerance is needed	Between -40°F and 200°F	Down to 50°F	SP-10	2.5 - 5.0	Denso Protal 7200 (EPC) Total DFT: 25 to 30 mils Color: Green
Underground steel piping, valves, and fittings	PC-13	Damp Surfaces	Between 41°F and 150°F	Between 41°F and 150°F	SP-10	2.5 - 5.0	Denso Protal 7300 (EPC) Total DFT: 30 to 60 mils Color: Gray
Underground steel piping, valves, and fittings	PC-14	High Service Temperature	Up to 250°F, with peeks to 300°F	Down to 50°F		2.5 - 5.0	Denso Protal 7900HT (EPC) Total DFT: 30 to 60 mils Color: Gray
Underground steel piping, valves and fittings	PC-22	Where surface preparation tolerance is needed	Between -43°F and 160°F	Down to 37°F (substrate temperature)	SP-3	-	Viscowrap – ST (VTW) Color: Blue
			Between -31°F d 212°F	Down to 37°F (substrate temperature)	SP-3	-	Viscowrap – HT (VTW) Color: Blue
		Flange Filling Paste	Between -43°F and 176°F	Down to 68°F (substrate temperature)	SP-3	-	Viscopaste (PST) Color: Blue

Table 3 Coating Systems for Transition Areas

Environment	System No	Category Item	Service Temperature	Ambient Application Temperature	Surface Prep, SSPC-SP	Anchor Profile, Mils	Product
		UV Mechanical Protection (Required for Aboveground Viscowrap)	Up to 185°F	Down to 41°F (substrate temperature)	-	-	PE Outerwrap (TW) Color: Black
		UV Mechanical Protection (Required for Aboveground Viscowrap)	Up to 185°F	Down to 41°F *(substrate temperature)*	-	-	PVC Outerwrap (TW) Color: Black
Underground steel piping, valves and fittings	PC-23	Piping, Valves, Pumps, Difficult to Protect Areas. Below Ground Use (Primer Required)	Between -50°F and 120°F	Between 0°F and 100°F	SP-2	-	Trenton Wax Tape #1 (TW) Color: Brown
Underground steel piping, valves and fittings	PC-24	Below and Above Ground Use (Primer Required)	Between -50°F and 120°F	Between 0°F and 100°F	SP-2	-	Trenton Wax Tape #2 (TW) Color: White
Underground steel piping, valves and fittings	PC-25	Where surface preparation tolerance is needed	Up to 145°F	Down to 45°F	SP-3	-	Polyguard RD-6 (TW) Color: Black
		UV Mechanical Protection (Required for Aboveground RD-6)	Up to 170°F	Between 40°F and 130°F	-	-	Polyguard RD-6 UVO Overcoat (EPC) Color: White
Underground steel piping, valves and fittings	PC-26	Below and Above Ground Use	Between -20°F and 140°F	-	-	-	Chase Corporation Tapecoat H50 Gray (TW) Color: Gray

Type Codes:

EPC	Epoxy Pipeline Coating	PST	Paste
LC	Liquid Coating	TW	Tape Wrap
VTW	Viscoelastic Tape Wrap		

APPENDIX B DEW POINT CALCULATION CHART

Table 4 Dew Point Calculation Chart

Ambient Air Temperature °F		20	30	40	50	60	70	80	90	100	110	120
% Relative Humidity	90	18	28	37	47	57	67	77	87	97	107	117
	85	17	26	36	45	55	65	75	84	95	104	113
	80	16	25	34	44*	54	63	73	82	98	102	110
	75	15	24	33	42	52	62	71	80	91	100	108
	70	13	23	31	40	50	60	68	78	88	96	105
	65	12	20	29	38	47	57	66	76	85	93	103
	60	11	19	27	36	45	55	64	73	83	92	101
	55	9	17	25	34	43	53	61	70	80	89	98
	50	6	15	23	31	40	50	59	67	77	86	94
	45	4	13	21	29	37	47	56	64	73	82	91
	40	1	11	18	26	35	43	52	61	69	78	87
	35	-2	8	16	23	31	40	48	57	65	74	83
	30	-6	4	13	20	28	36	44	52	61	69	77

	Coating of Transition Areas	ENG-STD-0009 Rev 0 Page 11 of 12

APPENDIX C COATING SYSTEM DIAGRAMS

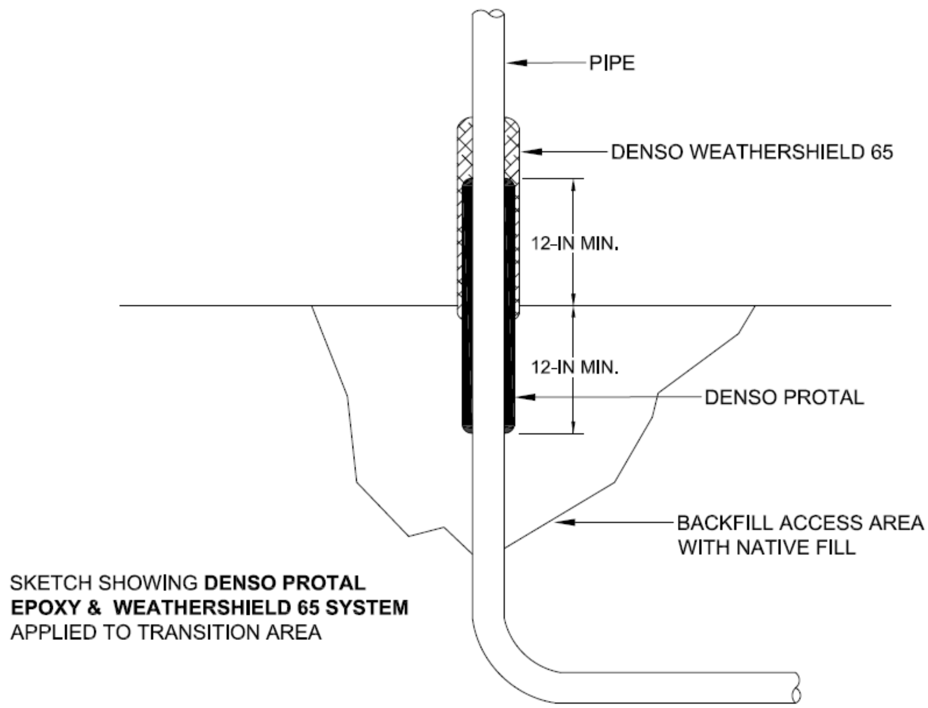


Figure 1 Epoxy System – Denso System

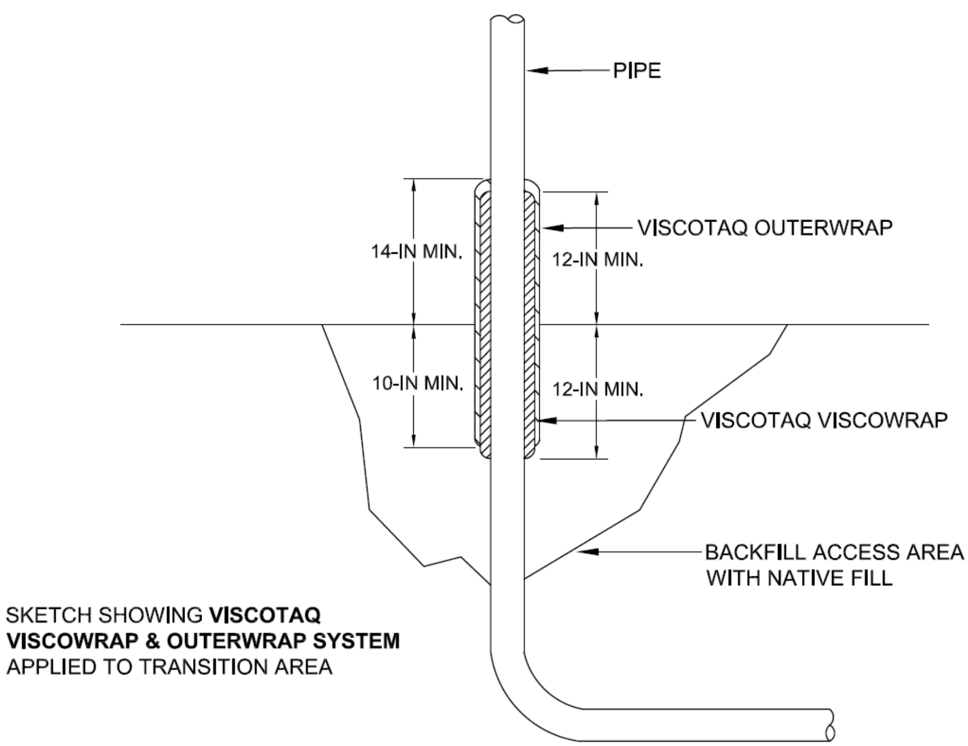


Figure 2 Two Tape System – Viscotaq System

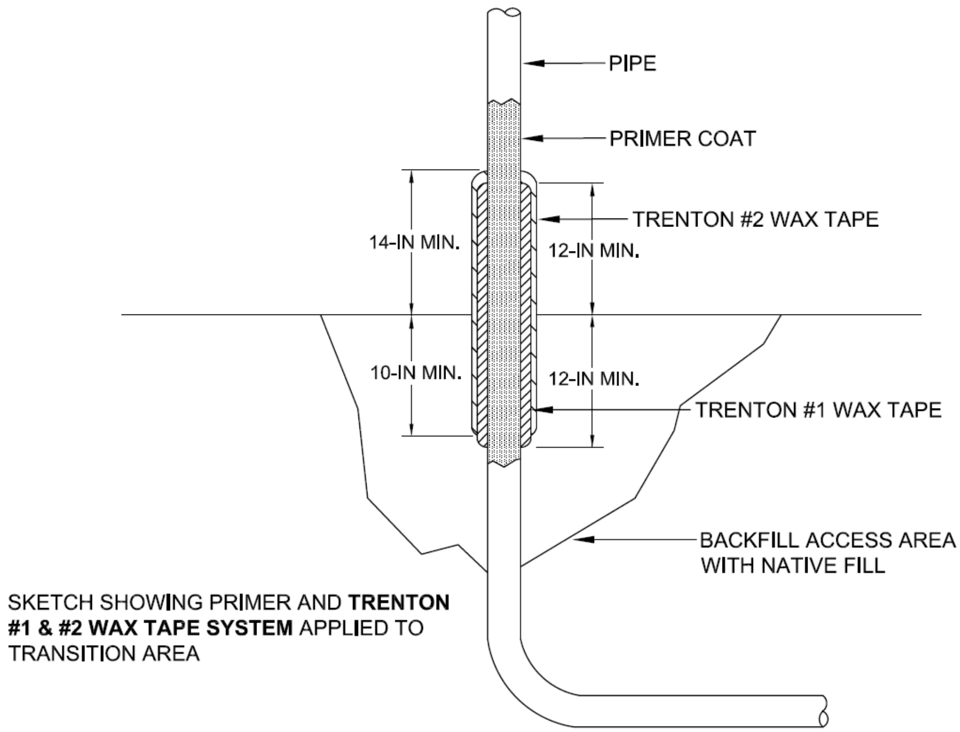


Figure 3 Two Tape System – Trenton Wax Tape System

	Engineering Standard	ENG-STD-0010	
	Plant Applied Coating Specification	Page 1 of 9	
		DATE: 4/1/2021	**Rev:** 0

Contents

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for surface preparation and coating applications of plant applied coatings for underground pipelines to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended coating service life for the asset.
- Standardization of work procedures, materials, color schemes, and inspection requirements as they pertain to plant applied fusion bonded epoxy coating.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

1.2.2 When purchasing existing pre-coated FBE pipe, only Section 8.0 (Inspection and Quality Control) of this Standard shall apply.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- ENG-STD-0006-FOR-01 Pipeline Coating Packet Form
- ENG-STD-0006-FOR-03 Coating Variance Request Form
- ENG-STD-0008 Coating of Underground Pipe Standard

2.2 Industry Codes and Standards

- NACE SP0394-2013 Application, Performance, and Quality Control of Plant-Applied, Fusion-Bonded Epoxy External Pipe Coating
- SSPC SP-1 Solvent Cleaning
- SSPC SP-10 Near-White Blast Cleaning

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard

Table 1 Definitions

Term	Definition
Anchor Profile	The profile of minute projections formed on a metal surface by sandblasting, shot blasting, or chemical etching; used to enhance the adhesiveness of a surface coating.
Contractor	Company or business that agrees to furnish linings or perform specified services at a specified price and/or rate to MPLX.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Curing	Setting up or hardening, generally due to a polymerization reaction between two or more chemicals (rein and curative).
Flocking	The process of spraying fusion bonded epoxy onto a substrate.
Holiday	A discontinuity of coating that exposes the metal surface to the environment.
Inspector/ Person in Charge (PIC)	An MPLX appointed engineer or inspector.
Manufacturer	Direct or indirect producer of linings, fabricated components, or subassemblies.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.

4.0 REQUIREMENTS

4.1 When applying Fusion Bonded Epoxy coating of line pipe, MPLX may furnish a qualified third-party pipe coating inspector for all pipe coating. The third-party pipe coating inspector shall, at a minimum, be NACE Coating Inspector Level I Certified.

4.2 The Company shall have the right to designate and send to the Contractor facility, as applicable, an Inspector for the purpose of confirming proper coating operations and observing any coating test. The Inspector shall have free access to the Contractor facility during all times when the Company's pipe is being handled (unloaded, loaded, coated, etc.).

4.3 Inspector shall have the authority to interpret these specifications and reject any pipe with coating that does not conform to these specifications. Rejected pipe shall have the coating removed and shall be cleaned and recoated at the Contractor's expense.

4.4 The coating Contractor shall be responsible for furnishing all labor, materials, quality control, tools, and equipment to assure that the coating is applied to the pipe in accordance with these specifications.

4.5 The FBE coating shall be applied and inspection test conducted according to NACE SP0394 and the references in Section 2.0. In the case of a difference between these specifications and NACE SP0394 and the referenced company standards, these company standards shall rule. All differences shall be brought to the attention of the Regional Corrosion Control Team Lead or Engineer

5.0 SURFACE PREPARATION AND INSPECTION

5.1 Bare pipe arriving at the Contractor's facility shall be inspected by Contractor upon arrival. All damaged or defective pipe found during unloading shall be segregated, shall not be coated and shall be noted on trucking or rail bills of lading to indicate types of damage and number of joints. Any pipe later found (not detected during unloading) to have dents, gouges, damaged bevels, etc., shall be determined as to the origin of the damage and any pipe damaged by Contractor. If damaged by the Contractor, the Contractor shall make necessary repairs including cost of pipe (not repairable) at Contractor's expense.

5.2 Prior to blast cleaning, bare pipe shall be inspected by the Contractor for loose mill scale, oil, grease, tar, asphalt, and miscellaneous foreign matter such as, but not limited to, salts and soil. All joints of pipe with such contaminates shall be noted and set aside for pre-cleaning. Pipe that requires solvent removal of deleterious material shall have such material removed by solvent cleaning in accordance with SSPC SP-1 requirements.

5.3 Prior to pre-heat and blast cleaning, the pipe surface shall be cleaned of all contaminates so as to avoid contamination of abrasive media and imbedding into anchor profile.

5.4 The pipe surface shall be preheated to above the dew point and sufficiently to remove all surface moisture prior to blast cleaning. Pipe shall be preheated in a uniform manner to avoid distortion. The preheat temperature shall not exceed 180 degrees Fahrenheit.

5.5 The pipe surface shall be abrasive blast cleaned to "near white finish" in accordance with SSPC SP-10. The abrasive shall be selected to achieve an angular anchor profile with a minimum depth of 1.5 mils to a maximum depth of 4.0 mils. A consistent abrasive working mix shall be maintained by frequent additions of small quantities of new abrasive.

5.6 After cleaning and prior to final heating, the pipe surface shall be inspected for adequate cleaning and surface condition. Improperly cleaned pipe shall be rejected and rerun at the Contractor's expense. Surface imperfections such as slivers, scabs, burrs, and weld spatter shall be removed by hand filing or light grinding so as not to diminish wall thickness and as long as the anchor profile or cleaning quality is not impaired in the process. For grind areas exceeding two square inches, the anchor profile shall be restored before coating application. No more than one percent surface area shall have disturbed anchor profile.

5.7 Following cleaning and prior to heating, any abrasive remaining inside the pipe shall be removed by air blast, vacuum system, or other suitable means.

5.8 If acid washing is required before coating application, the time between cleaning and acid washing the pipe shall be kept to a minimum to avoid excessive oxidation of the cleaned surface. Visual indication of such oxidation shall be cause for the pipe to be re-cleaned.

5.9 Prior to heating before coating application, an acid wash using Phosphoric acid solution (example Makita 33 or 31) wash treatment may be applied to the cleaned pipe surface. The following steps shall constitute a Phosphoric acid wash treatment:

1. A solution of 1-part acid (example Makita 33) to 9 parts clean water shall be applied at the rate of 1 gallon per 100 sq. ft. of pipe surface. The solution shall be agitated as required to prevent settling of the mix.
2. Treatment shall be for a minimum of 20 seconds with the pipe surface temperature between 110 degrees Fahrenheit and 150 degrees Fahrenheit. Treatment time shall be extended at the rate of one second for each degree below 110 degrees Fahrenheit.
3. Thorough, clean, high-pressure water rinse shall follow to remove any residue. A minimum of 2-1/2 gallons of fresh water per 100 square feet of pipe surface shall be used.

5.10 Visual indication of excessive oxidation shall be cause for the pipe to be re-cleaned.

6.0 COATING MATERIALS

6.1 The Coating Contractor shall use only the products listed in Table 2, unless approved by the Regional Corrosion Control Team Lead or Engineer.

6.2 Any deviations from the products listed in Table 2 shall be accompanied with a completed and signed copy of the ENG-STD-0006-FOR-03 "Coating Variance Request Form".

7.0 COATING APPLICATION

7.1 The pipe shall be heated to a minimum temperature of 450 degrees Fahrenheit, keeping in accordance with coating powder manufacturer's specifications with reference to the size and wall thickness of the pipe. The pipe shall be continually checked for proper temperature prior to coating by use of "simplistic" heat and/or electronic heat indicators. Pipe heated in excess of 525 degrees Fahrenheit shall be metallurgical inspected for acceptability. The costs of the metallurgical inspection and any rejected pipe shall be borne by the Contractor.

7.2 The use of reclaimed powder from previous jobs shall not be permitted. Powder older than one year shall not be used. Powder of lesser age shall not be permitted if storage conditions are considered unacceptable by inspector and powder manufacturer's specifications.

7.3 Coating powder shall immediately be applied using electrostatic spray guns to a uniform minimum and maximum thickness of specified mils. Electrostatic equipment shall be adjusted for maximum efficiency to minimize the amount of powder which may be recycled. Use of recycled coating material shall be permitted if adequate recovery and 80 or finer mesh screening equipment is used and maintained. An adequate recycle system shall properly blend recycled and virgin coating material into the delivery system. At no time shall more than 25% recycled powder be mixed in with virgin powder.

7.4 Air used to fluidize, transport, and apply the coating powder shall be commercially dry and free of oil or other contaminants.

7.5 The minimum cure time and temperatures shall conform to the coating manufacturer's specifications, keeping in accordance with reference to the size and wall thickness of the pipe.

7.6 Coating material shall not be applied closer than 1-1/2" or farther than 2-1/2" from the beveled ends of the pipe.

8.0 INSPECTION AND QUALITY CONTROL

8.1 Preparation for Inspection

After sufficient curing, the coated pipe shall be water quenched to 200 degrees Fahrenheit or less to permit handling for inspection. This temperature may need to be adjusted according to the size and wall thickness of the piping but shall be approved by the Purchaser.

8.2 Coating Thickness

8.2.1 Three randomly distributed coating thickness measurements shall be made along the length and around the circumference of each pipe joint. Calibration of the gauge shall be verified three times per day (at start up a.m., at start up after lunch, and at end of shift), utilizing U.S. Bureau of Standards certified coating thickness calibration standards.

8.2.2 Any joint of pipe with less than the specified minimum mils and more than the specified maximum mils dry film thickness shall be rejected. The rejected joint shall have the coating completely removed prior to recoating according to this specification.

8.3 Coating Holidays

8.3.1 Coated pipe surfaces shall be 100% electrically inspected by the Contractor with a holiday detector equipped with an audible signaling device.

8.3.2.1 In addition to holiday testing at the factory, all piping shall be holiday tested again on-site prior to being lowered into the ditch.

8.3.2 The holiday detector wand shall be placed in contact with the bare pipe in the cutback area of each joint to assure the operation of the signaling device.

8.3.3 The holiday detector shall be DC type. Instruments shall be set to 125 volts per mil, based on the specified minimum cured film thickness.

8.3.4 The holiday detector shall be checked periodically, at least three times a day, and adjusted by the Contractor to ensure detection of an intentional holiday through the thickest coating on pipe and to ensure proper voltage is being maintained. The times and results of these verifications shall be documented by the Inspector.

8.3.5 All holidays shall be clearly marked for repair.

8.3.6 Generally, the number of holidays per joint reflects the quality of surface preparation before coating, proper coating thickness, or both. All joints containing greater than one holiday per 20 square foot for pipe OD 20 inches or less and 30 square foot for pipe with OD greater than 20 inches shall be rejected and recoated at the Contractor's expense.

9.0 TESTING

9.1 Laboratory testing of coated pipe shall be conducted each day, on a minimum of two pipe joints. The first test of each day shall be initiated on one of the first 15 joints after start-up. The test results shall determine whether application changes are necessary.

9.2 Each day, the Contractor shall supply a coated sample of pipe from two joints, 18 inches in length, labeled by coating date and joint number. Inspector may choose from which joints of pipe to cut the sample. The testing required in Section 9 shall be conducted on a portion of these 18" samples and the remainder shall be retained for history backup. Problems detected in coating may necessitate additional pipe samples for test.

9.3 Laboratory tests shall include the following:

1. Bend test: coating shall not disbond, delaminate, crack, or break when bent 3 degrees per pipe diameter (OD) at 32 degrees Fahrenheit.
2. Cathodic disbondment: coating shall not cathodically disbond more than 8 mm radius from 3 mm (1/8-in) diameter holiday in 24 hours at 150 degrees Fahrenheit in 3% NACL under 3.5 VDC.
3. Porosity levels: under no circumstances shall "foam bond" (cellular porosity) be tolerated. "Foam bond" is a condition resembling soap bubbles on the steel surface, where only thin membranes of coating separate the pores. Generally, such a condition shall permit easy gouging and stripping of the coating with a simple knife test. The extent of foaming at the interface and throughout the film may not exceed a rating of three using the Bell and Stephens foam evaluation guide.

10.0 TRACKING, STENCILING, AND RECORD KEEPING

10.1 Each joint of coated pipe shall be permanently marked externally with the following information:

- Company name.
- Size, weight, grade, wall thickness, heat #, and mfg.
- Coating Contractor and location.
- Coating manufacturer and product number.
- Month and year coated.
- Stencil each end on single random and double random length, stencil each end and middle on triple random length.

10.2 The Contractor shall keep daily production tallies which shall contain the following information:

- Date and coating sequence number.
- Joint number.
- Coating thickness.
- Holiday (jeep) count.
- Disposition (accepted, rejected, diverted for cutoff or re-beveling, etc.).

10.3 Daily production tallies and results of all production tests shall be documented, and copies made available to the Regional Corrosion Control Team Lead or Engineer . Any apparent pipe steel defects detected after coating shall be clearly marked with a highly visible permanent marker on the finished coating. "Apparent pipe steel defects" shall be taken to mean any deep scratch or gouge which deformed the metal in any way; any dent that is greater than 0.250” deep, is longer than 1/2 the pipe diameter, or affects a longitudinal seam; or any longitudinal weld defect.

11.0 REPAIRS

11.1 Mechanical damage to the coated surface shall be repaired by the Contractor unless inspector deems complete stripping and recoating is necessary.

11.2 Prior to repairs, the area surrounding the defect shall be abraded utilizing 80 grit carborundum or equivalent. No files shall be used for holiday repair.

11.1.1 All repaired holidays shall be holiday inspected post repair.

12.0 STORAGE, HANDLING AND SHIPPING REQUIREMENTS

12.1 Pipe (both bare and coated) shall be stacked in a manner to prevent egging, buckling, or other damage. Pipe shall not be stored in close proximity to HVAC power lines, or other electrical hazards. If the pipeline is to be installed in a shared right-of-way, special worker safety considerations may apply.

12.2 Any timbers used in pipe racks shall be untreated, clean wood.

12.3 Pipe (both bare and coated) shall be elevated at least six inches off the ground. Never store pipe directly on the ground.

12.4 Pipe racks shall be clean of any contaminates that might contaminate the bare pipe or damage the coating on coated pipe.

12.5 Pipe racks shall be of sufficient height to prevent water from contaminating the interior or exterior of the pipe and shall be constructed (at slight a tilt) to allow water to drain from each joint of racked pipe.

12.6 All rows of pipe shall be restrained to prevent joints from rolling.

12.7 For coated pipe, pipe racks shall have a sufficient number of padded runs (timber skids or metal piping or structural steel), properly spaced and leveled to support the coated pipe without damage. The padded runs shall be clean and free of embedded debris such as rocks, glass, wire, and dirt.

12.8 The rows of coated pipe shall not be nested but separated with adequate clean stripping lumber.

12.9 All pipe shall be handled in such a manner as to prevent damage to pipe walls, beveled ends, internal, and external surfaces. All hooks or forks used for pipe handling shall be padded to prevent damage to the pipe and coating.

12.10 Pipe shall be separated during handling and shipping using tight weave polypropylene rope. The spacers shall be designed and placed so that all joints are separated to prevent coating-to-coating contact of the joints. A minimum of four spacers should be placed on 40-foot joints and shorter. A minimum of 6 spacers should be placed on 60-foot joints.

12.11 Each pipe load shall have sufficient banding and standards (chocks) to securely hold it in place to prevent shifting of pipe during transit. At no time shall any direct metal-to-coating contact be allowed during handling or shipping.

APPENDIX A - FUSION BONDED EPOXY COATING SYSTEMS

Table 2 Plant Applied Coating Systems for Underground Piping

Environment	System No	Category Items	Service Temperature	Ambient Application Temperature	Surface Prep, SSPC-SP	Anchor Profile MILS	Product
Underground new factory coated steel piping installations	PC-1	Shop Applied Fusion Bonded Epoxy	Between -100°F and 230°F	Contact Manufacturer	SP-10	1.5 - 4.0	3M Scotchkote 6233 (FBE) **Total DFT:** 8 to 16 Mils **Color:** Green
		"Abrasion Resistant Overlay" Applied Over	Between -100°F and 230°F	Contact Manufacturer	See PDS	-	3M Scotchkote 6352 (ARO) **Total DFT:** 15 to 35 Mils **Color:** Brown
Underground new factory coated steel piping installations	PC-2	Shop Applied Fusion Bonded Epoxy	Up to 225°F	Contact Manufacturer	SP-10	2.0 - 4.5	Dupont Nap-Gard 2500 Series (FBE) **Total DFT:** 12 to 24 Mils **Color:** Red
		"Abrasion Resistant Overlay" Applied Over	Contact Manufacturer	Contact Manufacturer	See PDS	-	Dupont Nap-Rock 7-2610 (ARO) **Total DFT:** Contact Manufacturer **Color:** Gray
Underground new factory coated steel piping installations	PC-3	Shop Applied Fusion Bonded Epoxy	Between -100°F and 230°F	Contact Manufacturer	SP-10	2.0 Min.	Valspar Pipeclad 2000 (FBE) **Total DFT:** 12 to 16 Mils **Color:** Green
		"Abrasion Resistant Overlay" Applied Over	Contact Manufacturer	Contact Manufacturer	See PDS	-	Valspar Pipeclad 2040 Series (ARO) **Total DFT:** 10 to 60 Mils **Color:** Black
Underground new factory coated steel piping installations and bore pipe	PC-4	"Abrasion Resistant Overlay" Applied Over	Up to 140°F	Between 40°F and 120°F	Abrade FBE	-	Polyclad ARO (ARO)

Environment	System No	Category Items	Service Temperature	Ambient Application Temperature	Surface Prep, SSPC-SP	Anchor Profile MILS	Product
							Total DFT: 25 to 125 Mils **Color:** Tan
Underground new factory coated steel piping installations and bore pipe	PC-5	"Abrasion Resistant Overlay" Applied Over	Up to 140°F	Between -20°F and 120°F	SP-10 (Bare Steel) SP-7 (FBE Coated)	3.0 – 4.0 (Bare Steel) 2.0 min (FBE Coated)	Powercrete J ARO (ARO) **Total DFT:** 20 Mils Typ. **Color:** Brown
Underground new factory coated steel piping installations and bore pipe	PC-6	"Abrasion Resistant Overlay" Applied Over	Up to 150°F	Down to 50°F	Abrade FBE	-	Denso Protal ARO (ARO) **Total DFT:** 30 to 60 Mils **Color:** Red
Underground new factory coated steel piping installations and bore pipe	PC-7	"Abrasion Resistant Overlay" Applied Over	Contact Manufacturer	Down to 41°F	See PDS	-	3M Scotchkote 328 (ARO) **Total DFT:** 40 to 100 Mils **Color:** Blue-Green

Types of Codes:

FBE Fusion Bonded Epoxy

ARO Abrasion Resistance Overlay

MPLX	Operating Standard	OPS-STD-0017	
	Corrosion Control Governing Standard	Page 1 of 17	
		DATE: 4/1/2021	Rev: 0

Contents

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for the inspection and mitigation of corrosion of pipelines (e.g. valve site) and facilities (e.g. tanks, piping, vessels, etc.) to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life for the asset.
- Standardization of survey and work procedures, materials, and inspection requirements as they pertain to the mitigation of internal and external corrosion.

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021
NOTICE: The information contained herein is the confidential property of MPLX unless another source is indicated. This material is subject to return on demand and must not be disclosed or reproduced without prior written consent by a duly authorized representative of MPLX.			
OPS-STD-0017 Corrosion Control Governing Standard.docx			

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

2.0 REFERENCES

The following governing requirements are incorporated by reference in this Standard.

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- OPS-STD-0017-FOR-01 Corrosion Control Program Annual Review Form
- OPS-STD-0018 Atmospheric Corrosion Monitoring, Inspection and Mitigation
- OPS-STD-0018-FOR-01 Atmospheric Corrosion Monitoring, Inspection and Mitigation Form
- OPS-STD-0019 Internal Corrosion Monitoring and Mitigation
- OPS-STD-0020 Aboveground Cathodic Protection Surveys
- OPS-STD-0020-FOR01 Reference Electrode Calibration Form
- OPS-STD-0020-FOR02 CIS Determination for New Pipelines Form
- OPS-STD-0021 Cathodic Protection Test Point Monitoring and Maintenance
- OPS-STD-0022 Cathodic Protection Rectifier and Interference Bond Monitoring and Maintenance
- OPS-STD-0023 Electrical Isolation Monitoring and Maintenance
- OPS-STD-0023-FOR-01 Electrical Short Notification & Mitigation Plan Form
- OPS-STD-0024 DC Interference Monitoring and Mitigation
- OPS-STD-0024-FOR01 DC Interference Monitoring and Mitigation Form
- OPS-STD-0025 AC Interference Monitoring and Mitigation
- OPS-STD-0026 Corrosion Under Insulation Monitoring, Inspection and Mitigation
- OPS-STD-0026-FOR-01 Corrosion Under Insulation Monitoring, Inspection and Mitigation Form
- OPS-STD-0027 External Corrosion Direct Assessment
- OPS-STD-0027-FOR-01 ECDA Process Form
- OPS-STD-0027-FOR-02 ECDA Data Elements Form
- OPS-STD-0027-FOR-03 ECDA-SCCDA Indirect Inspection Tools Selection Form
- OPS-STD-0027-FOR-04 ECDA Regional Analysis Form
- OPS-STD-0027-FOR-05 ECDA-SCCDA Indication Severity Classification Summary Form
- OPS-STD-0027-FOR-06 ECDA-SCCDA Dig Data Collection Form
- OPS-STD-0027-FOR-07 ECDA Re-Assessment Interval Form
- OPS-STD-0028 Stress Corrosion Cracking Direct Assessment
- OPS-STD-0028-FOR-01 SCCDA Process Form
- OPS-STD-0028-FOR-02 SCCDA Data Elements Form

- OPS-STD-0028-FOR-03 SCCDA Regional Analysis Form
- OPS-STD-0028-FOR-04 SCCDA Re-Assessment Interval Form
- ENG-STD-0004 Cathodic Protection for Buried or Submerged Metallic Structures
- ENG-STD-0005 Cathodic Protection for Tank Bottoms
- ENG-STD-0006 Coating of Aboveground Pipelines and Facilities
- ENG-STD-0006-FOR-01 Pipeline Coating Packet Form
- ENG-STD-0006-FOR-02 Tank Coating Packet Form
- ENG-STD-0006-FOR-03 Coating Variance Request Form
- ENG-STD-0007 Internal Tank Lining
- ENG-STD-0008 Coating of Underground Pipe
- ENG-STD-0009 Coating of Transition Areas
- ENG-STD-0010 Plant Applied Coating Specification
- MPLX Integrity Management Plan

2.2 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

2.3 Other

- TSCP-006 Cathodic Protection Survey Procedures
- TSIC-006 Internal Corrosion Survey Procedures
- MPLX Standard Corrosion Control Drawings

3.0 DEFINITIONS

Table 1 Definitions

Term	Description
Cathodic Protection	A technique to control corrosion of a metal surface by making it the cathode in an electrochemical cell.
Contractor	Company or business that agrees to furnish materials or perform specified services at a specified price and/or rate to the Owner.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
MPLX	For the purpose of this standard, MPLX shall mean MPLX, Markwest, and Southwest Gathering.

4.0 ROLES AND RESPONSIBILITIES

4.1 Clear definition of employee roles and responsibilities is critical to the successful implementation of this program. Roles and responsibilities are noted in the individual Corrosion Control Standard documents, as applicable.

4.1.1 The Corrosion Control Team Lead is responsible for overseeing Corrosion Control Program training of MPLX personnel.

Table 2 Roles and Responsibilities

Role	Responsibilities
Regional Corrosion Control Team Lead Regional Corrosion Control Engineer	➢ Manage Corrosion Control Program ➢ Supervise Regional Corrosion Control Operations Personnel ➢ Budgeting for Corrosion Control Maintenance and Installations ➢ Corrosion Control Database (PCS) Administrator ➢ Review Corrosion Control Deficiencies ➢ Identify and Develop Plan to Remediate Rectifier and Interference Bond Deficiencies ➢ Identify and Develop Plan to Remediate Annual CP Survey Deficiencies ➢ Identify and Develop Plan to Remediate CIS Deficiencies ➢ Identify and Develop Plan to Remediate Atmospheric Corrosion Deficiencies ➢ Identify and Develop Plan to Remediate Internal Corrosion Deficiencies
Regional Personnel for External Corrosion Control (i.e. Regional Corrosion Control Technicians/Specialists)	➢ Collect Rectifier and Interference Bond Readings ➢ Conduct Annual CP Surveys ➢ Conduct Close Interval Surveys (CIS) ➢ Conduct Atmospheric Corrosion Inspections ➢ Conduct Induced AC Surveys ➢ Install/Repair Rectifiers, Interference Bonds & Groundbeds ➢ Install/Repair Test Leads ➢ Coat Air-to-Soil Interfaces ➢ AC Corrosion Remediation
Regional Personnel for Internal Corrosion Control (i.e. Regional Corrosion Control Technicians/Specialists)	➢ Analyze Product Samples ➢ Analyze Results of Cleaning Pig Runs ➢ Determine Frequency of Cleaning Runs ➢ Pull and Analyze Internal Corrosion Monitors (Probes/Coupons)

4.2 Qualifications for Corrosion Control Supervisors

4.2.1 Management and supervisory personnel whose responsibilities relate to direct supervision of persons responsible for implementation of MPLX's Corrosion Control Program shall possess and maintain a thorough knowledge of the Corrosion Control Program and of the Program's elements for which the supervisor is responsible. MPLX personnel who qualify as the supervisor for a Regional Corrosion Control Team shall hold the minimum required NACE certifications, or be part of a prescribed plan to attain the certification, for the specified area of corrosion control expertise as specified in Appendix D.

4.1.2.1 An active Professional Engineering License, whose professional activities include suitable experience in corrosion control, will also qualify an individual for the above responsibilities.

4.2.2 In the absence of these required certifications, the supervisor for a Regional Corrosion Control Team shall defer their responsibilities for overseeing the area of Corrosion Control expertise to personnel that meet the above requirements.

If the supervisor does not have qualified personnel to perform these tasks, they may utilize the services of a competent, qualified contractor or consultant.

4.3 Corrosion Control Training

4.3.1 All key personnel involved in the administration, planning, interpretation, and/or execution of corrosion control activities shall have the appropriate level of competency for the role that they serve. They shall have demonstrable knowledge of the processes, procedures, and tools utilized. This skill-set can be established through related background experience, related training (i.e. NACE), or a formal engineering degree.

4.3.2 It is MPLX's policy is to ensure that all employees are thoroughly trained and competent to handle the specific areas for which they are responsible. Personnel involved in corrosion control activities shall meet the qualification requirements described in MPLX Operator Qualification (OQ) Program.

5.0 CORROSION CONTROL PROGRAM

5.1 Per §192.605(a), §192.605(b)(8) and §195.402(a), all Corrosion Control Standards referenced in Appendix A in the Corrosion Control Governing Standard shall be reviewed annually, not exceeding fifteen (15) months, by the Corrosion Control Team Lead or Engineer and documented through Critical Task Manager (CMT). The review shall be documented using the OPS-STD-0017-FOR-01. Appropriate changes are to be made when identified to ensure that the procedures described in the program remain effective. Recommendations and findings from this periodic Program Review shall be used to identify training needs and programs as required.

5.1.1 This review shall also include an annual assessment and report of any existing gaps in Corrosion Control Supervisor qualifications.

5.2 Appendix A lists the documents which are part of the Corrosion Control Program while Appendix B discusses the applicable Corrosion Control Program documents with regards to 49 CFR Parts 192 and Part 195.

6.0 DOCUMENTATION

6.1 Documents related to Corrosion Control referenced in the Pipeline Integrity Management Program - Liquid Pipelines or in the Pipeline Integrity Management Program - Gas Pipelines must be retained as required by those programs. This includes, but is not limited to, documentation to support the decisions, analyses, and actions taken to implement and evaluate each element of the Corrosion Control or Integrity Management programs.

6.2 Upon construction or acquisition of a pipeline, MPLX shall ensure that key Corrosion Control required documentation, as defined in Appendix C of this document, is obtained if available from previous owner/operators and maintained per the retention schedule specified in Appendix C.

6.3 Any deviations from processes specified in this program, or individual Corrosion Control process documents, shall be per the requirements provided in the exception process contained within the applicable Corrosion Control process document. Documentation of process deviations is required as specified in the exception process. Such documentation shall be maintained according to the retention policy Appendix C.

7.0 POLICY ON RELEASE OF INFORMATION

7.1 MPLX's Corrosion Control Program and associated data is proprietary in nature and is not available to the public. Information or data requests, both regulatory and public, must be referred to the Compliance Department.

8.0 PROGRAM DISTRIBUTION

8.1 The Corrosion Control group shall have the responsibility for maintenance and distribution of this Document. Distribution shall be handled in the following manner and through the Management of Change process, as applicable:

The most recent version in effect shall be maintained on the Logistics Standards Library.

- Upon update of the plan, the Corrosion Control Team Lead shall notify each internal stakeholder of the change.
- The only controlled copy is maintained on the Logistics Standards Library. Printed copies are considered to be uncontrolled.

8.2 Regional Stakeholders

- Corrosion Control Team Lead
- Corrosion Control Technicians / Specialists / Engineers
- Directors, Engineering
- Directors, Integrity & Reliability
- Directors, Operations
- Directors, Capital Projects
- Senior Managers, Construction
- Area Managers

APPENDIX A – CORROSION CONTROL PROGRAM DOCUMENTS

Documents	
OPS-STD-0017	Corrosion Control Governing Standard
OPS-STD-0017-FOR-01	Corrosion Control Program Annual Review Form
OPS-STD-0018	Atmospheric Corrosion Monitoring, Inspection and Mitigation
OPS-STD-0018-FOR-01	Atmospheric Corrosion Monitoring, Inspection and Mitigation Form
OPS-STD-0019	Internal Corrosion Monitoring and Mitigation
OPS-STD-0020	Aboveground Cathodic Protection Surveys
OPS-STD-0020-FOR01	Reference Electrode Calibration Form
OPS-STD-0020-FOR02	CIS Determination for New Pipelines Form
OPS-STD-0021	Cathodic Protection Test Point Monitoring and Maintenance
OPS-STD-0022	Cathodic Protection Rectifier and Interference Bond Monitoring and Maintenance
OPS-STD-0023	Electrical Isolation Monitoring and Maintenance
OPS-STD-0023-FOR-01	Electrical Short Notification & Mitigation Plan Form
OPS-STD-0024	DC Interference Monitoring and Mitigation
OPS-STD-0024-FOR01	DC Interference Monitoring and Mitigation Form
OPS-STD-0025	AC Interference Monitoring and Mitigation
OPS-STD-0026	Corrosion Under Insulation Monitoring, Inspection and Mitigation
OPS-STD-0026-FOR-01	Corrosion Under Insulation Monitoring, Inspection and Mitigation Form
OPS-STD-0027	External Corrosion Direct Assessment
OPS-STD-0027-FOR-01	ECDA Process Form
OPS-STD-0027-FOR-02	ECDA Data Elements Form
OPS-STD-0027-FOR-03	ECDA-SCCDA Indirect Inspection Tools Selection Form
OPS-STD-0027-FOR-04	ECDA Regional Analysis Form
OPS-STD-0027-FOR-05	ECDA-SCCDA Indication Severity Classification Summary Form
OPS-STD-0027-FOR-06	ECDA-SCCDA Dig Data Collection Form
OPS-STD-0027-FOR-07	ECDA Re-Assessment Interval Form
OPS-STD-0028	Stress Corrosion Cracking Direct Assessment
OPS-STD-0028-FOR-01	SCCDA Process Form
OPS-STD-0028-FOR-02	SCCDA Data Elements Form
OPS-STD-0028-FOR-03	SCCDA Regional Analysis Form
OPS-STD-0028-FOR-04	SCCDA Re-Assessment Interval Form
ENG-STD-0004	Cathodic Protection for Buried or Submerged Metallic Structures
ENG-STD-0005	Cathodic Protection for Tank Bottoms
ENG-STD-0006	Coating of Aboveground Pipelines and Facilities
ENG-STD-0006-FOR-01	Pipeline Coating Packet Form
ENG-STD-0006-FOR-02	Tank Coating Packet Form
ENG-STD-0006-FOR-03	Coating Variance Request Form
ENG-STD-0007	Internal Tank Lining
ENG-STD-0008	Coating of Underground Pipe
ENG-STD-0009	Coating of Transition Areas
ENG-STD-0010	Plant Applied Coating Specification
TSCP-006	Cathodic Protection Survey Procedures

Documents	
TSIC-006	Internal Corrosion Survey Procedures
	MPLX Standard Corrosion Control Drawings
	MPLX Integrity Management Plan
	MPLX Operator Qualification Program

APPENDIX B – APPLICABLE CORROSION CONTROL DOCUMENTS TO 49 CFR PARTS 192 AND 195

49 CFR Part 192 Corrosion Enforcement Guidance Sections	Covered Under Standard(s)
General	
§192.451 Scope	OPS-STD-0017
§192.452(a) Applicability to Converted Pipelines	ENG-STD-0004
§192.452(b) Applicability to Converted Pipelines	ENG-STD-0004
§192.453 General	OPS-STD-0017
§192.483(a) Remedial Measures: General	ENG-STD-0008 ENG-STD-0009 OPS-STD-0024
§192.483(b) Remedial Measures: General	ENG-STD-0004
§192.483(c) Remedial Measures: General	ENG-STD-0004
§192.485(a) Remedial Measures: Transmission Lines	MPLX Integrity Management Plan
§192.485(b) Remedial Measures: Transmission Lines	MPLX Integrity Management Plan
§192.485(c) Remedial Measures: Transmission Lines	MPLX Integrity Management Plan
§192.487(a) Remedial Measures: Distribution Lines Other Than Cast Iron or Ductile Iron Lines	MPLX Integrity Management Plan
§192.487(b) Remedial Measures: Distribution Lines Other Than Cast Iron or Ductile Iron Lines	MPLX Integrity Management Plan
§192.489(a) Remedial Measures: Cast Iron and Ductile Iron Pipelines	MPLX Integrity Management Plan
§192.489(b) Remedial Measures: Cast Iron and Ductile Iron Pipelines	MPLX Integrity Management Plan
§192.490 Direct Assessment	OPS-STD-0027 OPS-STD-0028 MPLX Integrity Management Plan
§192.491(a) Corrosion Control Records	ENG-STD-0004
§192.491(b) Corrosion Control Records	ENG-STD-0004
§192.491(c) Corrosion Control Records	OPS-STD-0020
Buried or Submerged Pipelines	
Cathodic Protection	
§192.455(a) External Corrosion Control: Buried or Submerged Pipelines Installed After 7/31/1971	ENG-STD-0004
§192.455(b) External Corrosion Control: Buried or Submerged Pipelines Installed After 7/31/1971	ENG-STD-0004
§192.455(c) External Corrosion Control: Buried or Submerged Pipelines Installed After 7/31/1971	ENG-STD-0004
§192.455(d) External Corrosion Control: Buried or Submerged Pipelines Installed After 7/31/1971	ENG-STD-0004
§192.455(e) External Corrosion Control: Buried or Submerged Pipelines Installed After 7/31/1971	ENG-STD-0004
§192.455(f) External Corrosion Control: Buried or Submerged Pipelines Installed After 7/31/1971	ENG-STD-0004
§192.457(a) External Corrosion Control: Buried or Submerged Pipelines Installed Before 8/1/1971	ENG-STD-0004
§192.457(b) External Corrosion Control: Buried or Submerged Pipelines Installed Before 8/1/1971	ENG-STD-0004

49 CFR Part 192 Corrosion Enforcement Guidance Sections	Covered Under Standard(s)
§192.459 External Corrosion Control: Examination of Buried Pipeline When Exposed	OPS-STD-0027 MPLX Integrity Management Plan
§192.463(a) External Corrosion Control: Cathodic Protection	ENG-STD-0004
§192.463(b) External Corrosion Control: Cathodic Protection	ENG-STD-0004
§192.463(c) External Corrosion Control: Cathodic Protection	ENG-STD-0004
§192.465(a) External Corrosion Control: Monitoring	OPS-STD-0020
§192.465(b) External Corrosion Control: Monitoring	OPS-STD-0022 OPS-STD-0017
§192.465(c) External Corrosion Control: Monitoring	OPS-STD-0022 OPS-STD-0017
§192.465(d) External Corrosion Control: Monitoring	OPS-STD-0017
§192.465(e) External Corrosion Control: Monitoring	ENG-STD-0004
§192.467(a) External Corrosion Control: Electrical Isolation	OPS-STD-0023
§192.467(b) External Corrosion Control: Electrical Isolation	OPS-STD-0023
§192.467(c) External Corrosion Control: Electrical Isolation	OPS-STD-0023
§192.467(d) External Corrosion Control: Electrical Isolation	OPS-STD-0023
§192.467(e) External Corrosion Control: Electrical Isolation	OPS-STD-0023
§192.467(f) External Corrosion Control: Electrical Isolation	OPS-STD-0025
§192.469 External Corrosion Control: Test Stations	OPS-STD-0021
§192.471(a) External Corrosion Control: Test Leads	OPS-STD-0021
§192.471(b) External Corrosion Control: Test Leads	OPS-STD-0021
§192.471(c) External Corrosion Control: Test Leads	OPS-STD-0021
§192.473(a) External Corrosion Control: Interference Currents	OPS-STD-0025 OPS-STD-0024
§192.473(b) External Corrosion Control: Interference Currents	ENG-STD-0004
Coatings	
§192.461(a) External Corrosion Control: Protective Coating	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§192.461(b) External Corrosion Control: Protective Coating	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§192.461(c) External Corrosion Control: Protective Coating	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010

49 CFR Part 192 Corrosion Enforcement Guidance Sections	Covered Under Standard(s)
§192.461(d) External Corrosion Control: Protective Coating	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§192.461(e) External Corrosion Control: Protective Coating	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
Atmospheric Corrosion	
§192.479(a) Atmospheric Corrosion Control: General	ENG-STD-0006
§192.479(b) Atmospheric Corrosion Control: General	ENG-STD-0006
§192.479(c) Atmospheric Corrosion Control: General	ENG-STD-0006
§192.481(a) Atmospheric Corrosion Control: Monitoring	OPS-STD-0018 OPS-STD-0026
§192.481(b) Atmospheric Corrosion Control: Monitoring	OPS-STD-0018 OPS-STD-0026
§192.481(c) Atmospheric Corrosion Control: Monitoring	OPS-STD-0018 OPS-STD-0026
Internal Corrosion	
§192.475(a) Internal Corrosion Control: General	OPS-STD-0019
§192.475(b) Internal Corrosion Control: General	MPLX Integrity Management Plan
§192.476(a) Internal Corrosion Control: Design and Construction of Transmission Line	OPS-STD-0019
§192.476(b) Exceptions to Applicability	OPS-STD-0019
§192.476(c) Change to Existing Transmission Lines	OPS-STD-0019
§192.476(d) Records	OPS-STD-0019
§192.477 Internal Corrosion Control: Monitoring	OPS-STD-0019

49 CFR Part 195 Corrosion Enforcement Guidance Sections	Covered Under Standard(s) or LIM(s)
General	
§195.551 What do the Regulations in This Subpart Cover?	OPS-STD-0017
§195.555 What are the Qualifications for Supervisors?	OPS-STD-0017
§195.585(a) What Must I do to Correct Corroded Pipe?	MPLX Integrity Management Plan
§195.585(b) What Must I do to Correct Corroded Pipe?	MPLX Integrity Management Plan
§195.587 What Methods are Available to Determine the Strength of Corroded Pipe?	MPLX Integrity Management Plan
§195.589(a) What Corrosion Control Information do I Have to Maintain?	ENG-STD-0004
§195.589(b) What Corrosion Control Information do I Have to Maintain?	ENG-STD-0004
§195.589(c) What Corrosion Control Information do I Have to Maintain?	OPS-STD-0020
§195.591 In-Line Inspection of Pipelines	MPLX Integrity Management Plan
Buried or Submerged Pipelines	
Cathodic Protection	
§195.563(a) Which Pipelines Must Have Cathodic Protection?	ENG-STD-0004
§195.563(b) Which Pipelines Must Have Cathodic Protection?	ENG-STD-0004
§195.563(c) Which Pipelines Must Have Cathodic Protection?	ENG-STD-0004
§195.563(d) Which Pipelines Must Have Cathodic Protection?3	ENG-STD-0004
§195.565 How do I Install Cathodic Protection on Breakout Tanks?	ENG-STD-0005
§195.567(a) Which Pipelines Must Have Test Leads and What Must I do to Install and Maintain the Leads?	OPS-STD-0021
§195.567(b) Which Pipelines Must Have Test Leads and What Must I do to Install and Maintain the Leads?	OPS-STD-0021
§195.567(c) Which Pipelines Must Have Test Leads and What Must I do to Install and Maintain the Leads?	OPS-STD-0021
§195.569 Do I Have to Examine Exposed Potions of Buried Pipelines?	OPS-STD-0027 MPLX Integrity Management Plan
§195.571 What Criteria Must I Use to Determine the Adequacy of Cathodic Protection?	ENG-STD-0004
§195.573(a) What Must I do to Monitor External Corrosion Control?	OPS-STD-0020
§195.573(b) What Must I do to Monitor External Corrosion Control?	ENG-STD-0004
§195.573(c) What Must I do to Monitor External Corrosion Control?	OPS-STD-0022 OPS-STD-0017
§195.573(d) What Must I do to Monitor External Corrosion Control?	ENG-STD-0005
§195.573(e) What Must I do to Monitor External Corrosion Control?	OPS-STD-0017
§195.575(a) Which Facilities Must I Electrically Isolate and What Inspections Tests and Safeguards are Required?	OPS-STD-0023

49 CFR Part 195 Corrosion Enforcement Guidance Sections	Covered Under Standard(s) or LIM(s)
§195.575(b) Which Facilities Must I Electrically Isolate and What Inspections Tests and Safeguards are Required?	OPS-STD-0023
§195.575(c) Which Facilities Must I Electrically Isolate and What Inspections Tests and Safeguards are Required?	OPS-STD-0023
§195.575(d) Which Facilities Must I Electrically Isolate and What Inspections Tests and Safeguards are Required?	OPS-STD-0023
§195.575(e) Which Facilities Must I Electrically Isolate and What Inspections Tests and Safeguards are Required?	OPS-STD-0025
§195.577(a) What Must I do to Alleviate Interference Currents?	OPS-STD-0025 OPS-STD-0024
§195.577(b) What Must I do to Alleviate Interference Currents?	ENG-STD-0004
Coatings	
§195.557(a) Which Pipelines Must Have Coating for External Corrosion Control?	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§195.557(b) Which Pipelines Must Have Coating for External Corrosion Control?	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§195.559(a) What Coating Materials May I Use for External Corrosion Control?	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§195.559(b) What Coating Materials May I Use for External Corrosion Control?	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§195.559(c) What Coating Materials May I Use for External Corrosion Control?	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§195.559(d) What Coating Materials May I Use for External Corrosion Control?	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§195.559(e) What Coating Materials May I Use for External Corrosion Control?	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010

49 CFR Part 195 Corrosion Enforcement Guidance Sections	Covered Under Standard(s) or LIM(s)
§195.559(f) What Coating Materials May I Use for External Corrosion Control?	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§195.561(a) When Must I Inspect Pipe Coating Used for External Corrosion Control?	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
§195.561(b) When Must I Inspect Pipe Coating for External Corrosion Control?	ENG-STD-0008 ENG-STD-0009 ENG-STD-0010
Atmospheric Corrosion	
§195.581(a) Which Pipelines Must I Protect Against Atmospheric Corrosion and What Coating Material May I Use?	ENG-STD-0007
§195.581(b) Which Pipelines Must I Protect Against Atmospheric Corrosion and What Coating Material May I Use?	ENG-STD-0006
§195.581(c) Which Pipelines Must I Protect Against Atmospheric Corrosion and What Coating Material May I Use?	ENG-STD-0006
§195.583(a) What Must I do to Monitor Atmospheric Corrosion Control?	OPS-STD-0018 OPS-STD-0026
§195.583(b) What Must I do to Monitor Atmospheric Corrosion Control?	OPS-STD-0018 OPS-STD-0026
§195.583(c) What Must I do to Monitor Atmospheric Corrosion Control?	OPS-STD-0018 OPS-STD-0026
Internal Corrosion	
§195.579(a) What Must I do to Mitigate Internal Corrosion?	OPS-STD-0019
§195.579(b) What Must I do to Mitigate Internal Corrosion?	OPS-STD-0019
§195.579(c) What Must I do to Mitigate Internal Corrosion?	MPLX Integrity Management Plan
§195.579(d) What Must I do to Mitigate Internal Corrosion?	ENG-STD-0007

APPENDIX C – CORROSION CONTROL DATA RETENTION POLICY

49 CFR Part 192 Corrosion Control Data Retention		
Record	**Code**	**Retention Time**
Rectifiers	192.465(b)	5 years
CP Annual Reports		5 years
CP System Installation	192.455	5 years
CP Survey	192.465(a)	Life
Reverse Current Switches	192.465(c)	5 years
Diodes	192.465(c)	5 years
Galvanic Anodes	192.465(b)	5 years
Shorted Casing	192.705	5 years
Repair Interference Currents	192.465(d)	5 years
Critical Interference Bonds	192.465(c)	5 years
Test Stations (Including Casings)	192.465(a)	Life
Non-Critical Interference Bonds	192.465(a)	Life
Stray Current Mitigation	192.465(c)	5 years
Atmospheric Corrosion	192.481(a)	5 years
Offshore Atmospheric Corrosion	192.481(a)	5 years
Electrical Isolation		Life
Exposed Buried Pipe Inspection	192.459	5 years
CIS	Not Required	Life
Internal Corrosion Coupons	192.477	Life
Gas Samples	192.477; 192.475	Life
Liquid Samples	192.477	Life
Internal Inspection	192.475	Life
Buried Pipe Inspection	192.491; 192.459	Life
Active Corrosion Zones	192.465(e)	Life
Active Corrosion Zone when CP is Added	192.465(a)	Life
Coating Type	192.491(c) (192.455(b)) 192.491(c) (192.452(a); 192.455(a)(1); 192.455(a)(2); 192.455(b))	Life
Pipe Inspection Reports (External Coating Condition)	192.491(c) (192.459)	5 years
Test Station Maps	192.469	Life
Internal Corrosion Design Review	192.476(d)	Life
Remaining Strength Calculations	192.485(c)	5 years

49 CFR Part 195 Corrosion Control Data Retention		
Record	**Code**	**Retention Time**
Rectifiers	195.573(c)	5 years
CP Annual Report	195.573(a)(1)	Life
CP System Procedure Review	195.402(c)(3)	Life
Remaining Strength Calculations	195.589(c) (195.569)	5 years
Repair of Corrosion Control	195.589(c) (195.573(e))	5 years
Active Corrosion Review	195.589(c) (195.573(b)(1); 195.573(b)(2))	Life
Electrical Isolation	195.589(c) (195.575(a); 195.575(b); 195.575(c); 195.575(d))	5 years
Fault Current and Lightning Protection	195.589(c) (195.575(e))	5 years
CP System Maps	195.589(a) (195.589(b))	5 years
Test Stations	195.589(c) (195.573(a)(1))	5 years
Interference Bonds	195.589(c) (195.573(c))	5 years
Diodes	195.589(c) (195.573(c))	5 years
Reverse Current Switches	195.589(c) (195.573(c))	5 years
Coating Type	195.589(c) (195.557(a); 195.559; 195.401(c)) 195.589(c) (195.559; 195.561(a); 195.561(b))	5 years
Pipe Inspection Reports (External Coating Condition)	195.589(c) (195.569)	5 years
Inhibitors	195.589(c) (195.579(b)(1); 195.579(b)(2); 195.579(b)(3))	5 years
Internal Inspection	195.589(c) (195.579(c); 195.579(a))	5 years
Breakout Tank Inspections	195.589(c) (195.579(d))	5 years

APPENDIX D – MINIMUM REQUIRED NACE CERTIFICATIONS FOR CORROSION CONTROL SUPERVISORS

Area of Corrosion Control Expertise	**Minimum Required NACE Certification**
Installation, Operation, and Maintenance of External Corrosion Control Systems	CP-2
Design of External Corrosion Control Systems	CP-3
Installation, Operation, and Maintenance of Internal Corrosion Control Systems	Internal Corrosion Technologist
Design of Internal Corrosion Control Systems	Senior Internal Corrosion Technologist
Installation, Operation, and Maintenance of Internal/External Coating Systems	CIP-1

* An active Professional Engineering License, whose professional activities include suitable experience in corrosion control, will also qualify an individual for the above responsibilities.

MPLX	Corrosion Control Program Annual Review Form	OPS-STD-0017-FOR-01	
	FORM	Page 1 of 3	
		DATE: 4/1/2021	Rev: 0

Standard/Form	Date Reviewed	Reviewed By	Revision Proposed (Y/N)	Proposed Revision
OPS-STD-0017				
OPS-STD-0017-FOR-01				
OPS-STD-0018				
OPS-STD-0018-FOR-01				
OPS-STD-0019				
OPS-STD-0020				
OPS-STD-0020-FOR01				
OPS-STD-0020-FOR02				
OPS-STD-0021				
OPS-STD-0022				
OPS-STD-0023				
OPS-STD-0023-FOR-01				
OPS-STD-0024				
OPS-STD-0024-FOR01				
OPS-STD-0025				
OPS-STD-0026				
OPS-STD-0026-FOR-01				

MPLX	Corrosion Control Program Annual Review Form	OPS-STD-0017-FOR-01	
	FORM	Page 2 of 3	
		DATE: 4/1/2021	Rev: 0

Standard/Form	Date Reviewed	Reviewed By	Revision Proposed (Y/N)	Proposed Revision
OPS-STD-0027				
OPS-STD-0027-FOR-01				
OPS-STD-0027-FOR-02				
OPS-STD-0027-FOR-03				
OPS-STD-0027-FOR-04				
OPS-STD-0027-FOR-05				
OPS-STD-0027-FOR-06				
OPS-STD-0027-FOR-07				
OPS-STD-0028				
OPS-STD-0028-FOR-01				
OPS-STD-0028-FOR-02				
OPS-STD-0028-FOR-03				
OPS-STD-0028-FOR-04				
ENG-STD-0004				
ENG-STD-0005				
ENG-STD-0006				
ENG-STD-0006-FOR-01				

MPLX	Corrosion Control Program Annual Review Form	OPS-STD-0017-FOR-01	
	FORM	Page 3 of 3	
		DATE: 4/1/2021	Rev: 0

Standard/Form	Date Reviewed	Reviewed By	Revision Proposed (Y/N)	Proposed Revision
ENG-STD-0006-FOR-02				
ENG-STD-0006-FOR-03				
ENG-STD-0007				
ENG-STD-0008				
ENG-STD-0009				
ENG-STD-0010				

Comments

	Operating Standard	OPS-STD-0018	
	Atmospheric Corrosion Monitoring, Inspection and Mitigation	Page 1 of 9	
		DATE: 4/1/2021	Rev: 0

Contents

List of Figures

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for the inspection and mitigation of atmospheric (external) corrosion of pipelines (e.g. valve site) and facilities (e.g. tanks, piping, vessels, etc.) to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life for the asset.
- Standardization of work procedures, materials, and inspection requirements as they pertain to the mitigation of atmospheric corrosion.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

1.2.2 The scope of this Standard does not include the monitoring, inspection, and mitigation of corrosion under insulation (CUI). The monitoring, inspection, and mitigation of corrosion under insulation is covered under LO-10.022-STD.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- OPS-STD-0018-FOR-01 Atmospheric Corrosion: Monitoring, Inspection and Mitigation Form
- OPS-STD-0026 Corrosion Under Insulation Monitoring, Inspection and Mitigation Standard
- OPS-STD-0026-FOR-01 Corrosion Under Insulation Monitoring, Inspection and Mitigation Form
- ENG-STD-0006 Coating of Aboveground Pipelines and Facilities Standard
- ENG-STD-0006-FOR-01 Pipeline Coating Packet Form
- ENG-STD-0006-FOR-02 Tank Coating Packet Form
- ENG-STD-0006-FOR-03 Coating Variance Form
- ENG-STD-0009 Coating of Transition Areas Standard

2.2 Industry Codes and Standards

- ASME B31.3 Process Piping Code
- ASME B31.8 Gas Transmission and Distribution Piping Systems
- API 570 Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems
- API 2611 Terminal Piping Inspection-Inspection of In-Service Terminal Piping Systems

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Atmospheric	Metal-metal interface or elevated pipe spans. Also encompasses metal laying on top of non-metallic supports other than soil (e.g. wood, concrete, etc.).
Contractor	Company or business that agrees to furnish materials or perform specified services at a specified price and/or rate to MPLX.

Term	**Description**
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Holiday	A discontinuity of coating that exposes the metal surface to the environment.
Idled (Inactive)	A pipeline that is not currently used to transport gas or liquids, but continues to be maintained under 49 CFR Part 192 or 49 CFR Part 195.
Inspector/ Person in Charge (PIC)	An MPLX appointed engineer or inspector.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
Onshore	Situated or occurring on land.
Offshore (Marine)	Beyond the line or ordinary low water along that portion of the coast that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.
PCS	Pipeline Compliance System.
Transition	Soil-air interface. Also encompasses metal laying on top of soil and water-air interfaces.

4.0 INSPECTION INTERVAL

4.1 The pipeline system or portion of the pipeline system that is exposed to the atmosphere shall be inspected for evidence of atmospheric corrosion at the intervals listed below:

4.1.1 Onshore – At least once every three (3) calendar years, but with intervals not exceeding thirty-nine (39) months.

5.0 AREAS OF INTEREST

5.1 The inspection of the pipeline system or portion of the pipeline system that is exposed to the atmosphere shall give particular attention to pipe located at soil-to-air interfaces, under disbonded coatings, at pipe supports, , and in spans over water.

6.0 INSPECTION PROCEDURE

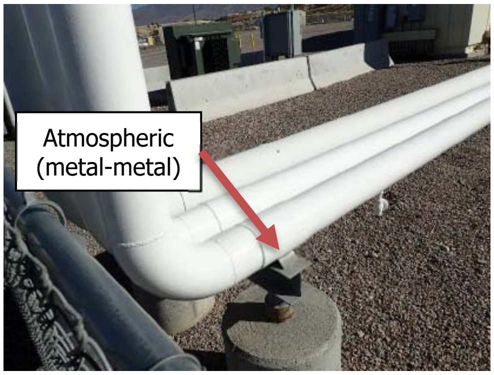
6.1 Individuals performing annual survey work shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

6.2 Atmospheric Corrosion Monitoring, Inspection and Mitigation Procedures shall be performed using MPLX Form OPS-STD-0018-FOR-01 or by using an Allegro Field PC and recording the fields listed in MPLX Form OPS-STD-0018-FOR-01 (preferred). Following the completion of the survey, the survey data shall be transferred to the PCS database within sixty (60) days of the survey completion date.

6.3 Atmospheric corrosion inspection survey data shall be retained per the retention schedule outlined in Appendix C of OPS-STD-0017.

6.4 All exposed areas of a pipeline and exposed in-yard piping shall be inspected for atmospheric corrosion.

6.5 Both atmospheric (metal-metal) interfaces and transition (soil-air) interfaces shall be evaluated for corrosion. Figure 1 shows an example of an Atmospheric interface and a Transition interface.



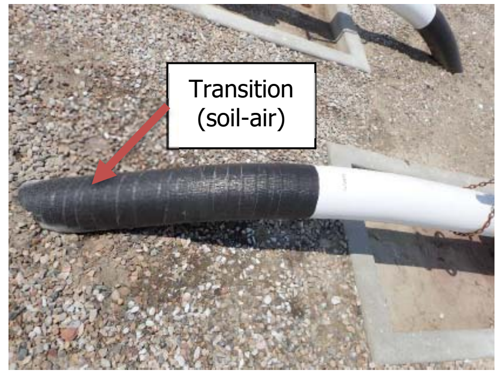


Figure 1 Atmospheric Interface (Left), Transition Interface (Right)

6.6 Appendix A contains priority classifications for atmospheric interfaces and Appendix B contains priority classifications for transition interfaces. Priority classifications consist of 3 priority ranges, with a 1 being the most severe and 3 being the least severe. Actions associated with Priorities are defined in the Section 7.0 of this Standard. Other locations such as splash zones and deck penetrations shall use the same priority system using sound judgment and examples present in Appendix A.

6.7 The Corrosion Control Technician or Qualified Operator shall use Appendix A & B of this Standard in the field and perform a visual inspection of all exposed areas of in-scope piping.

6.8 In the field, the Corrosion Control Technician or Qualified Operator shall assign priorities to all exposed areas of a pipeline system for each area of interest. If no signs are present of atmospheric corrosion, the Corrosion Control Technician or Operator shall classify it as Priority 3.

6.9 Photographs shall be taken at each assessed location and stored together with the survey data in the PCS database, which shall be retained per OPS-STD-0017.

6.10 Each exposed area shall be given a unique identifying label, i.e. PIC 01, for reference on future inspections. If piping circuits have been assigned under a prior API 570 or API 2611 inspection, use the piping circuits label as the identifying element.

7.0 CLASSIFICATIONS

7.1 MPLX personnel shall review third-party inspection reports and affirm or modify priority classifications

7.2 For areas classified as Priority 1 items, an engineering assessment of the metal loss using NDE methods shall be conducted under the guidance of an Integrity Engineer per the code associated with the pertinent regulatory agency. Where no regulatory agency has authority, an engineering assessment, along with remediation, shall be performed per ASME B31.3 (liquid service) or ASME B31.8 (gas service).

7.3 Areas classified as Priority 2 items shall be repaired by the next atmospheric inspection interval.

7.4 Areas classified as Priority 3 items shall be re-assessed at the standard atmospheric inspection interval and can be re-prioritized at any time.

8.0 REPAIRS

8.1 All repair items shall be assigned a work order and tracked in SAP-PM or Oracle.

8.2 Coating repairs on atmospheric piping shall follow the ENG-STD-0006 standard, while coating repairs on transition piping shall follow the ENG-STD-0009 standard.

8.1.1 Coating repairs shall be documented using the appropriate MPLX coating packet forms.

8.3 If metal loss requires repair by mechanical means (e.g. sleeve, weld-overlay, replacement pipe, etc.), an MPLX Pipeline Integrity Engineer shall be consulted to determine the proper type of repair.

9.0 SURVEY RECORD KEEPING

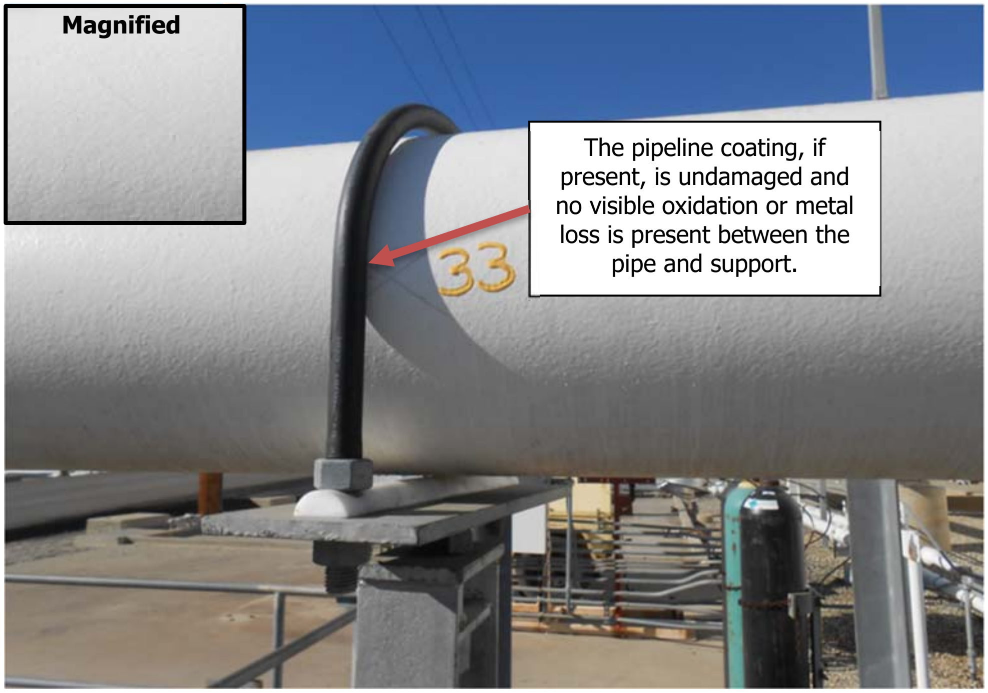
Table 2 Survey Record Keeping

Record	Owner	Location
Atmospheric Corrosion Inspection Survey	Regional Corrosion Control Team Lead or Engineer	PCS Database
Photographs of Piping Circuits	Regional Corrosion Control Team Lead or Engineer	PCS Database

APPENDIX A – ATMOSPHERIC PRIORITY CLASSIFICATIONS

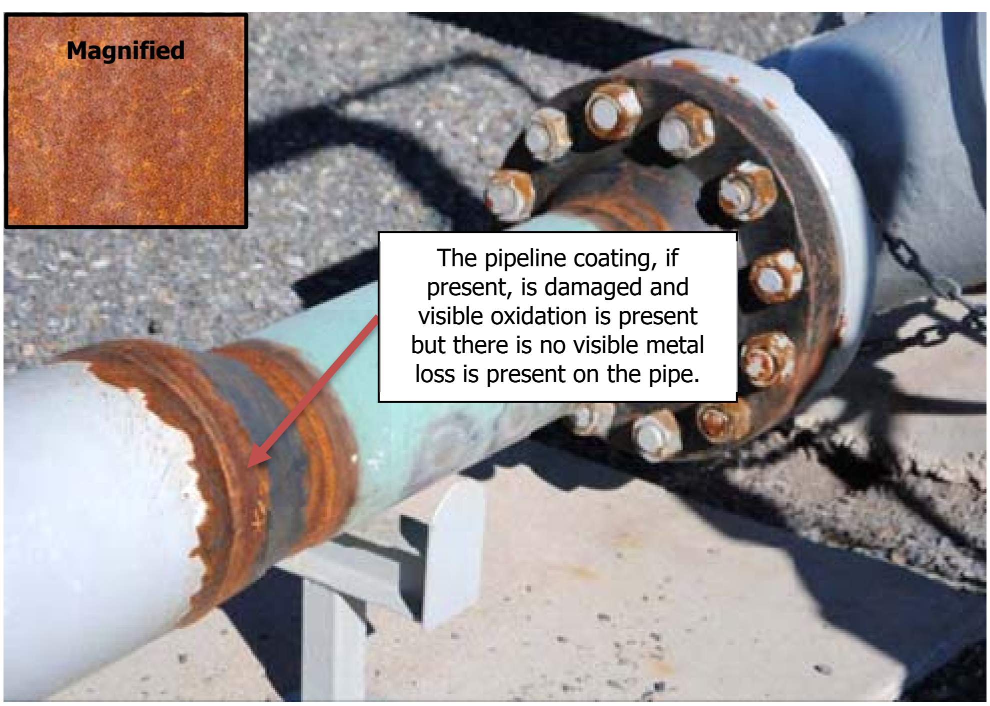
Priority 3

The pipeline coating, if present, is undamaged and no visible oxidation or metal loss is present.



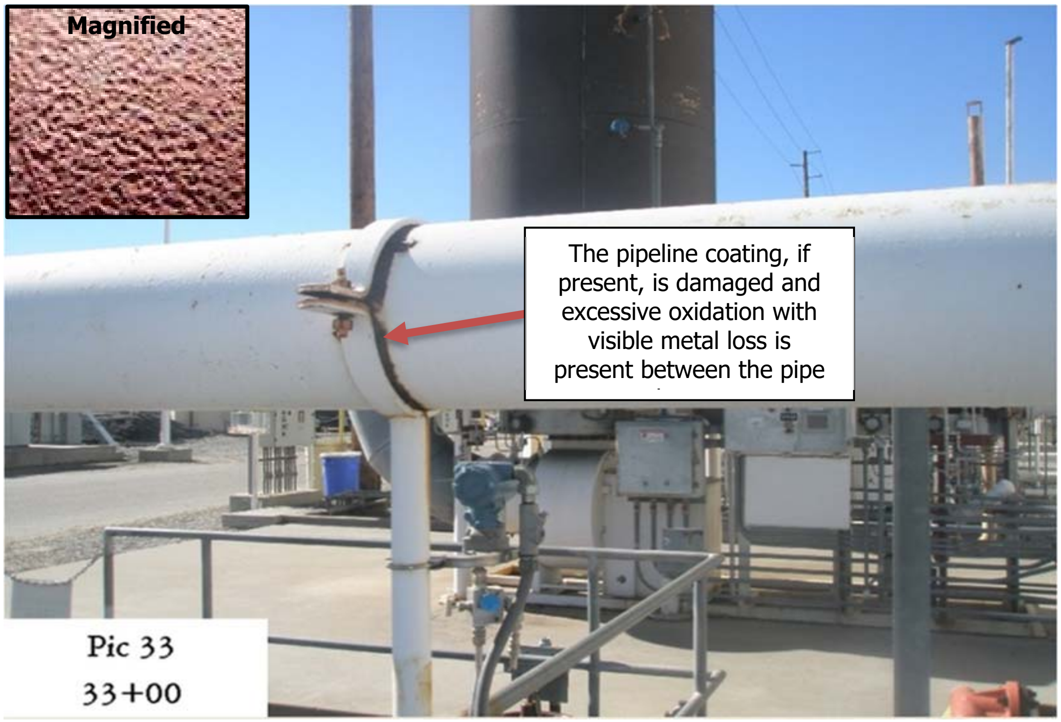
Priority 2

The pipeline coating, if present, is damaged and visible oxidation is present but there is no visible metal loss.



Priority 1

The pipeline coating, if present, is damaged and excessive oxidation with visible metal loss is present.

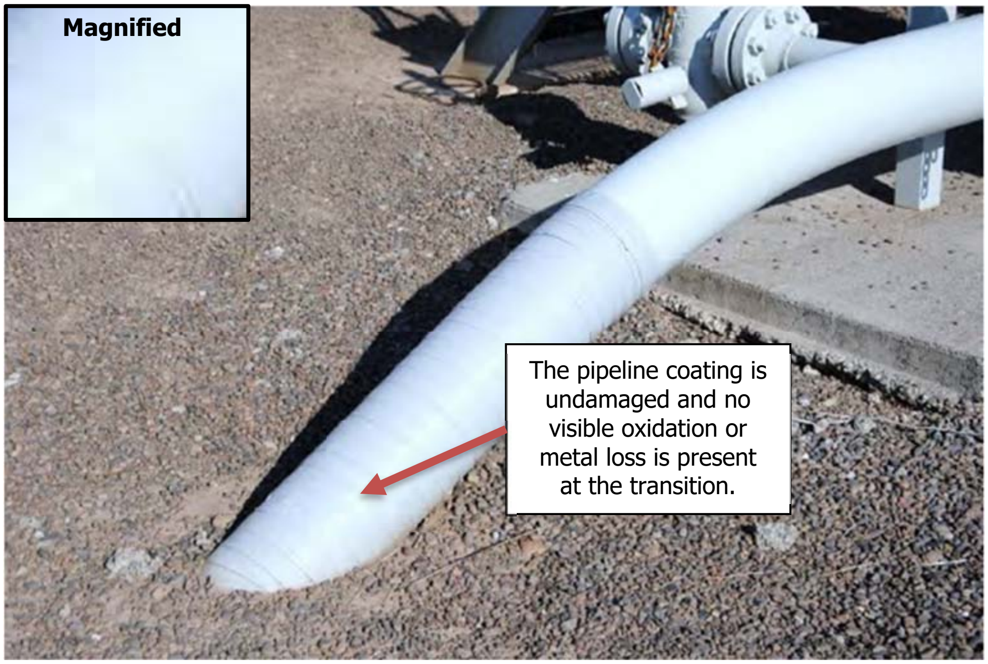


MPLX	Atmospheric Corrosion Monitoring, Inspection and Mitigation	OPS-STD-0018 Rev 1 Page 8 of 9

APPENDIX B – TRANSITION PRIORITY CLASSIFICATIONS

Priority 3

The pipeline coating is undamaged and no visible oxidation or metal loss is present.

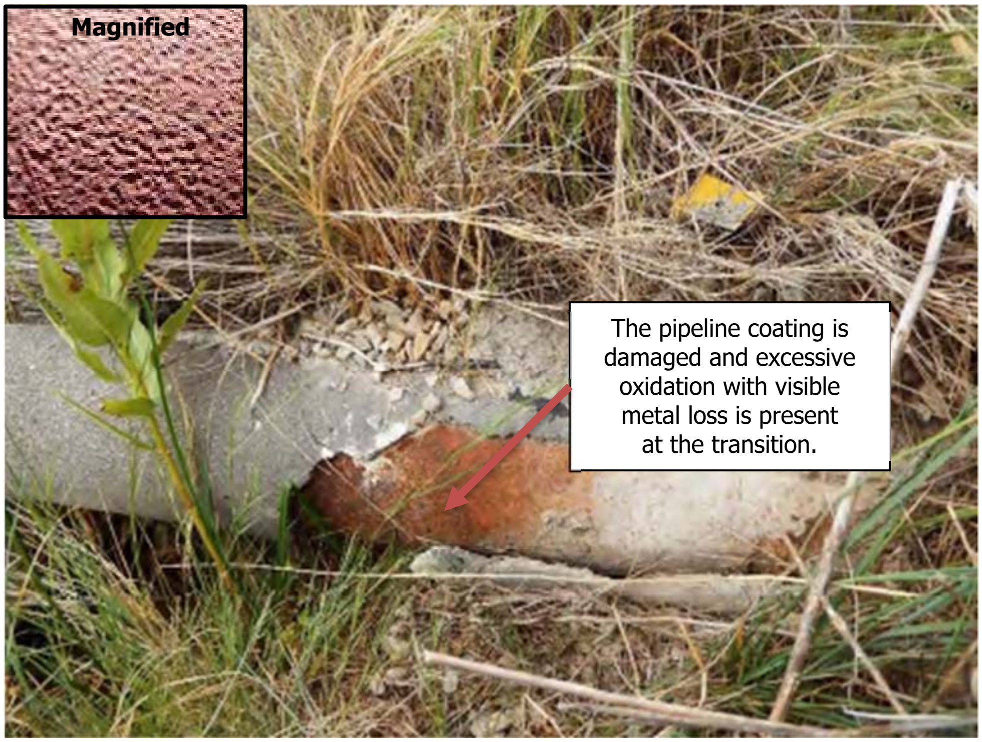


Priority 2

The pipeline coating is damaged and visible oxidation is present but there is no visible metal loss.

Priority 1

The pipeline coating is damaged and excessive oxidation with visible metal loss is present.



	Operating Standard	OPS-STD-0019	
MPLX	Internal Corrosion Monitoring and Mitigation	Page 1 of 5	
		DATE: 4/1/2021	Rev: 0

Contents

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for the inspection and mitigation of internal corrosion in pipelines and facilities (e.g. tanks, piping, vessels, etc.) to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life for the asset.
- Standardization of survey procedures and inspection requirements as they pertain to the mitigation of internal corrosion.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- MPLX IMP 06.1 "In-Line Inspection"
- "124A – Buried Pipeline Inspection" Form
- "124B - Buried Pipeline Investigation" Form
- TSIC-006 Internal Corrosion Survey Procedures

2.2 Industry Codes and Standards

- NACE SP0106-2006 Control of Internal Corrosion in Steel Pipelines and Piping Systems
- NACE TM0194-2014 Field Monitoring of Bacterial Growth in Oil and Gas Systems
- NACE SP0775-2013 Preparation Installation Analysis and Interpretation of Corrosion Coupons in Oilfield Operations

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Inline Inspection (ILI)	The evaluation of pipelines using "smart pigs" that utilize non-destructive examination techniques to detect and size internal damage.
Manufacturer	Direct or indirect producer of materials, fabricated components, or subassemblies.
Material Safety Data Sheet (MSDS)	A document that contains information on the potential health effects of exposure to chemicals, or other potentially dangerous substances, and on safe working procedures when handling chemical products.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
PCS	Pipeline Compliance System.
Product Data Sheet (PDS)	A document that summarizes the performance and other technical characteristics of a product.
Ultrasonic Testing (UT)	Using high frequency sound energy to conduct examinations and make measurements.

4.0 INTERNAL CORROSION DETECTION AND MEASUREMENT

4.1 General

4.1.1 The Regional Corrosion Control Team Lead or Engineer shall be responsible for identifying the corrosion constituents and where the likely source is located.

4.2 Visual Inspection

4.2.1 Individuals performing survey work shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

4.2.2 If a piping system is above ground or exposed and is opened to allow visual access (this includes cut outs), observations of the following shall be conducted by a qualified individual and recorded using both the "124A – Buried Pipeline Inspection" form and the "124B - Buried Pipeline Investigation" form:

- Evidence of corrosion on internal pipe surfaces. Types of damage shall be identified and recorded.
- Measurement of wall thickness in the most deeply corroded areas if corrosion damage does exist.
- Circumferential and longitudinal extent of corrosion on the pipe surface or any discernible pattern of attack.
- Position of attack with respect to the horizontal at the corroded section and with respect to the elevation of adjacent pipe section.
- Existence of deposits and corrosion under the deposits. A sample of the deposit shall be obtained for analysis.

4.2.3 Internal corrosion visual inspection data shall be retained per the retention schedule outlined in Appendix C of OPS-STD-0017.

4.3 Corrosion Coupons and Probes

4.3.1 Individuals performing work on internal corrosion coupons and probes shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

4.3.2 The use of properly located coupons and/or probes are an effective method for determining the existence, rate and type of internal corrosion. These devices shall be recommended by the Regional Corrosion Control Team Lead or Engineer.

4.3.3 Coupons and/or probes are installed in the gas or liquid stream to simulate the internal exposed surface. Corrosion monitoring devices shall be placed in a location where free water or water wetting is anticipated to be present.

4.3.4 Intrusive coupons or probes shall be retracted before pigging of a pipeline.

4.3.5 Recommended guidance for performing corrosion coupon and probe testing can be located in TSIC-006 "Internal Corrosion Survey Procedures".

4.3.6 Each coupon and probe shall be monitored at least two times each calendar year, not exceeding seven and a half months, and the data shall be entered into the PCS database within sixty (60) days of the end of the scheduled survey month.

4.3.7 Coupon and probe corrosion rates shall be categorized per the values below in Table 2 unless another categorization system is approved by the Regional Corrosion Control Team Lead or Engineer. If another categorization system is used, it shall be documented with the inspection data that is using it.

Table 2 Qualitative Categorization of Carbon Steel Corrosion Rates

Category	General Corrosion Rate (mpy)	Maximum Pitting Rate (mpy)
Low	< 1.0	< 5.0
Moderate	1.0 - 4.9	5.0 - 7.9
High	5.0 - 10	8.0 - 15
Severe	>10	>15

** Above table adopted from NACE SP0775-2013*

4.3.8 Internal corrosion coupon and probe survey data shall be retained per the retention schedule outlined in Appendix C of OPS-STD-0017.

4.4 Sampling

4.4.1 If product sampling is conducted to analyze for internal corrosion monitoring, the sampling shall be conducted in accordance with NACE TM0194-2004 and NACE SP0106-2006.

4.4.2 The Regional Corrosion Control Team Lead or Engineer shall be responsible for identifying the product sampling protocol and location(s).

4.4.3 Record all relevant sample analysis (e.g. gas & liquids analysis, solids analysis, bacteria testing, etc.) in the PCS database within sixty (60) days of receiving the analysis results.

4.4.4 Internal corrosion sample analysis data shall be retained per the retention schedule outlined in Appendix C of OPS-STD-0017.

4.5 In-Line Inspection (ILI)

4.5.1 In-line inspection tools may be employed for detecting mechanical integrity issues and internal/external corrosion damage.

4.5.2 For a complete guide on this type of procedure the following Standard Operating Procedure should be consulted first, MPLX IMP 06.1 "In-Line Inspection".

5.0 METHODS FOR CONTROLLING INTERNAL CORROSION

5.1 General

5.1.1 The recommended methods for controlling internal corrosion shall be determined by the Regional Corrosion Control Team Lead or Engineer based on the data analysis performed in Section 4.0.

5.1.2 The decision to proceed with mitigation measures will also depend on other factors such as the configuration and type of equipment (e.g. plant piping, pipelines, vessels, tanks, etc.), availability of pigging facilities, feasibility of chemical treatment, etc.

- In steel cross-country pipelines, options are usually limited to pipeline pigging and chemical inhibition.
- In Plant facilities, internal corrosion can often be controlled by coatings & linings, metallurgy, use of non-metallic materials, gas stripping, etc.

5.2 Maintenance Pigging

5.2.1 Cleaning pigs are used to improve and maintain internal pipe cleanliness by removing contaminants and deposits within the pipe.

5.2.2 Any pig inserted into a pipeline shall be clean and in good repair.

5.2.3 The Regional Corrosion Control Team Lead or Engineer shall be responsible for identifying the maintenance pig type and pigging frequency.

5.2.4 Operations should maintain records of cleaning pig runs by location including date and type of pig.

5.2.4.1 If product sampling from a maintenance cleaning pig run is conducted to analyze for internal corrosion monitoring, follow Section 4.4.1.

5.3 Corrosion Inhibitor/Biocide

5.3.1 Individuals performing the tasks of monitoring and controlling the injection rate of corrosion inhibitor or biocide shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

5.3.2 Addition of corrosion inhibitor or biocide shall be considered a corrosion mitigation measure when corrosive gases or liquids are transported.

5.3.3 The initial name, quantity, and frequency of inhibitors or biocides, and other treating chemicals used shall be recorded and the document shall be retained per the retention schedule outlined in Appendix C of OPS-STD-0017.

6.0 SURVEY RECORD KEEPING

Table 3 Survey Record Keeping

Record	Owner	Location
Coupon/Probe Survey Data	Regional Corrosion Control Team Lead or Engineer	PCS Database
Internal Corrosion Sampling Analysis Data	Regional Corrosion Control Team Lead or Engineer	PCS Database

	Operating Standard	OPS-STD-0020	
	Aboveground Cathodic Protection Surveys	Page 1 of 17	
		DATE: 4/1/2021	Rev: 0

Contents

List of Tables

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for the inspection and mitigation of external corrosion on pipelines (e.g. valve site) and facilities (e.g. tanks, piping, vessels, etc.) using cathodic protection to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life for the asset.
- Standardization of survey procedures and inspection requirements as they pertain to the mitigation of external corrosion.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- OPS-STD-0020-FOR01 Reference Electrode Calibration Form
- OPS-STD-0020-FOR02 Close Interval Survey Determination for New Pipelines Form
- OPS-STD-0021 Cathodic Protection Test Point Monitoring and Maintenance
- OPS-STD-0022 Cathodic Protection Rectifier and Interference Bond Monitoring and Maintenance
- OPS-STD-0023 Electrical Isolation Monitoring and Maintenance
- OPS-STD-0024 DC Interference Monitoring and Mitigation
- OPS-STD-0025 AC Interference Monitoring and Mitigation

2.2 Industry Standards

- NACE SP0169-2007 Control of External Corrosion on Underground or Submerged Metallic Piping Systems
- NACE SP0207-2007 Performing Close Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

2.4 Other

- TSCP-006 Cathodic Protection Survey Procedures

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Anode	An electrode that is characterized by electron loss.
Cathode	An electrode that is characterized by electron gain.
Cathodic Protection	A technique to control corrosion of a metal surface by making it the cathode in an electrochemical cell.
Continuity Bond	A metallic connection that provides electrical continuity.
Contractor	Company or business that agrees to furnish materials or perform specified services at a specified price and/or rate to MPLX.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Current Density	The current per unit area.
Electrical Isolation	The condition of being substantially electrically separated from other metallic structures and the environment.
Electrode Potential	The potential of an electrode as measured against a reference electrode.
Electrolyte	A medium through which electrically charged particles (ions) may travel. Typically soil, water, or product in this application.
Foreign Structure	Any structure that is not part of the subject structure.
Galvanic Anode	Typically a prepackaged assembly consisting of an active metal (Mg, Zn, etc.) in a moisture retaining backfill. Generally any metal which is more electrochemically active in a multi-metal system.
Galvanic Series	A list of metals and alloys arranged according to their relative potentials in a given environment.
Half Cell Reference Electrode	See Reference Electrode.
Holiday	A discontinuity of coating that exposes the metal surface to the environment.
Impressed Current	Direct current supplied by a power source external to the electrode system.
Inspector/ Person in Charge (PIC)	An MPLX appointed engineer or inspector.
Insulating Coating System	All components comprising the protective coating, the sum of which provides effective electrical insulation of the coated structure.
Interference Bond	A metallic connection designed to control electrical current interchange between metallic systems.
Isolation	See Electrical Isolation.
Line Current	The direct current flowing on a pipeline.
Manufacturer	Direct or indirect producer of materials, fabricated components, or subassemblies.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
PCS	Pipeline Compliance System.

Table 1 Definitions

Term	Description
Purchaser	The party placing a direct purchase order. The Purchaser is the Owner's designated representative.
Reference Electrode	A device whose open circuit potential is constant under similar conditions of measurement.
Galvanic Protection	Reduction or prevention of corrosion of a metal in an electrolyte by galvanically coupling it to a more anodic metal.
Shared Electrolyte	Electrolyte in contact with both the electrode and the structure.
Stray Current	Current flowing through paths other than the intended circuit.
Stray Current Corrosion	Corrosion resulting from current flowing through paths other than the intended circuit.
Structure-to-Electrolyte Voltage (Also, Structure-to-Soil Potential or Pipe-to-Soil Potential)	The voltage difference between a metallic structure and reference electrode in contact with a shared electrolyte.
Structure-to-Structure Voltage (Also, Structure-to-Structure Potential)	The difference in voltage between metallic structures in a common electrolyte.
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.

4.0 CRITERIA FOR CATHODIC PROTECTION

The following protection criteria are applicable to buried or submerged pipelines that are protected from external corrosion using a cathodic protection system(s).

4.1 General

4.1.1 Potential measurements on pipelines shall be made with the reference electrode located on the electrolyte surface as close as practicable to the pipeline. Such measurements on all other structures shall be made with the reference electrode positioned as close as feasible to the structure surface being investigated. Consideration shall be given to voltage (IR) drops other than those across the structure-electrolyte boundary, the presence of dissimilar metals, and the influence of other structures for valid interpretation of potential measurements.

4.1.2 No single criterion for evaluating the effectiveness of cathodic protection has proven to be satisfactory for all conditions. If required, the Regional Corrosion Control Team Lead or Engineer shall evaluate the data on a case by case basis to determine the criteria for cathodic protection that shall be used.

4.2 Criteria for Steel Structures

4.2.1 A potential of -0.85 volts or more negative shall be measured with respect to a saturated copper/copper sulfate reference electrode contacting the electrolyte in a neutral pH to demonstrate adequate cathodic protection of the structure at that location. This potential may be either a direct measurement of the polarized potential or a current-applied potential. Interpretation of a current-applied potential shall require consideration of the significance of voltage drops in the earth and metallic paths.

4.2.2 A minimum negative (cathodic) polarization voltage shift of 100 millivolts shall be measured between the structure surface and a stable reference electrode contacting the electrolyte in a neutral pH to demonstrate adequate cathodic protection of the structure at that location.

4.2.2.1 Either the formation or the decay of polarization can be used to satisfy this criterion.

4.3 Criteria for Dissimilar Metal Structures

4.3.1 A negative (cathodic) voltage between all structure surfaces and a stable reference electrode contacting the electrolyte equal to that required for the most anodic metal should be maintained to demonstrate adequate cathodic protection of the structure at that location.

- For the case of continuous copper and steel, steel is the most anodic metal, and a potential of at least -0.85 volts between the structure surface and a stable reference electrode contacting the electrolyte shall be used.
- A minimum negative (cathodic) polarization voltage shift of 100 millivolts between the structure surface and a stable reference electrode contacting the electrolyte shall not be used.
- The 100 mV polarization criteria may be used, with approval from the Regional Corrosion Control Team Lead or Engineer, for steel piping that is electrically continuous with copper grounding if on-site testing has been conducted and documented that shows the copper grounding has no influence on the steel's potential.

4.3.2 Amphoteric materials, which could be damaged by high alkalinity, shall be electrically isolated with insulating flanges or the equivalent per OPS-STD-0023.

4.4 Special Considerations

4.4.1 Abnormal conditions sometimes exist where protection is ineffective or only partially effective using the above criteria. For the below abnormal conditions, the following criteria shall be used to evaluate whether or not the structure is receiving adequate cathodic protection:

4.4.1.2 Electrolyte temperatures in excess of 140 degrees Fahrenheit:

- A potential of at least -0.95 volts, not -0.85 volts, between the structure surface and a stable reference electrode contacting the electrolyte shall be used.
- A minimum negative (cathodic) polarization voltage shift of 200 millivolts, not 100 millivolts, between the structure surface and a stable reference electrode contacting the electrolyte shall be used.

4.4.1.2 When active MIC has been identified or is probable:

- A potential of at least -0.95 volts, not -0.85 volts, between the structure surface and a stable reference electrode contacting the electrolyte shall be used.
- A minimum negative (cathodic) polarization voltage shift of 200 millivolts, not 100 millivolts, between the structure surface and a

stable reference electrode contacting the electrolyte shall be used.

4.4.2 The Regional Corrosion Control Team Lead or Engineer shall evaluate abnormal conditions not addressed above on a case by case basis to determine what criteria for cathodic protection to use and when it has been effectively met.

5.0 ANNUAL SURVEYS

5.1 General

5.1.1 Individuals performing annual survey work shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

5.1.2 Pipe-to-electrolyte potential surveys shall be conducted over cathodically protected pipeline and other applicable facilities at least annually, but with intervals not exceeding 15 months.

5.1.3 Annual survey data shall be documented in the PCS database within sixty (60) days of the survey completion date.

5.1.4 Annual survey data shall be retained per the retention schedule outlined in Appendix C of OPS-STD-0017.

5.2 Survey Grouping

5.2.1 A single pipe-to-electrolyte reading at a test point only validates a single point on the pipeline system.

5.2.2 Test points shall be put into a logical grouping, designated by pipeline segment rights-of-way or facilities, to facilitate cathodic protection evaluations. This will allow trend analysis over a large area, and aid in the filing and documentation of the survey as required by Federal, State, and Local Regulations.

5.3 Pipeline Contact

5.3.1 Pipeline contacts are locations where contact with the pipeline can be made such as test leads, valves, spans, drips, risers, main line taps, etc.

5.3.2 Negative lead wires of a rectifier, galvanic anode ground bed lead wires, or interference bond station lead wires shall not be used as pipeline contacts to obtain structure-to-electrolyte potential readings. Metallic IR drops occur in these test leads, due to current flowing in the wire, and introduce an error into the structure-to-electrolyte potential reading. If a dedicated test lead has been installed at these locations, then that lead can be used as a pipeline contact.

5.3.3 Sufficient test points, as determined by the Regional Corrosion Control Team Lead or Engineer, shall be present to determine the adequacy of cathodic protection. The Annual Pipeline Survey may not require the use of all existing test points.

5.3.4 All existing survey data shall be maintained for the life of the asset unless prior approval is obtained from the Regional Corrosion Control Team Lead or Engineer to deactivate the test point.

5.4 Test Points

5.4.1 This is the point over the approximate centerline of the pipeline where the reference electrode (half-cell) shall be placed to take the potential reading.

5.4.2 Since the test point may vary from the "pipeline contact" location, the test point location designated by milepost/station number is the recorded data location.

5.4.3 Structure-to-electrolyte potentials taken through high resistance layers (blacktop, permafrost, macadam, etc.) may exhibit higher measurement error due to IR drop. When feasible, reference cell contact shall be made with the shared electrolyte.

5.4.4 It may be necessary to water the point of contact with the half-cell in areas of dry or high resistivity soils to lower the contact resistance of the half-cell to an acceptable level.

5.5 Reference Electrode Check

5.5.1 A reference electrode shall consist of a copper rod in a saturated copper-copper sulfate/distilled water solution. Other types of reference electrodes, such as silver-silver chloride, may be used in brackish or saltwater environments, but readings shall be converted to equivalent Cu-CuSO4 potentials.

5.5.2 Recommended guidance for testing and confirming reference electrode(s) are within tolerance can be located in TSCP-006 Cathodic Protection Survey Procedure 1 "Portable and Stationary Reference Electrode Calibration".

5.6 Survey Cycle

5.6.1 When an interrupted survey is performed, corresponding "On/Instant Off" potentials shall be logged for each location.

5.6.2 The normal survey interruption cycle of the current sources is 3-4 seconds "ON" and 1 second "OFF," sync with the "OFF," for a total duty cycle of 4-5 seconds. Other survey cycles may be used with approval of the Regional Corrosion Control Team Lead or Engineer. Multiple interrupters shall be GPS synchronized with time updates at least every 24 hours. Waveform generators and/or manually synchronized interrupters shall not be used.

5.6.3 The recording meter shall be capable of capturing and displaying these cycles in either real-time or near real-time.

5.7 Survey Meters

5.7.1 All annual surveys shall be performed using a multimeter, such as an American Innovations Allegro Field PC, that has been calibrated annually, not to exceed 15 months.

5.8 Survey Procedures

5.8.1 Recommended guidance for performing cathodic protection survey procedures can be located in TSCP-006 "Cathodic Protection Survey Procedures."

5.9 Minimum Pipeline Survey Data Requirements

5.9.1 Rectifier DC voltage and amperage outputs for each rectifier location.

5.9.2 A structure-to-electrolyte potential at each designated test point as defined by the computerized survey. These potentials normally consist of an "On" potential and an "Instant Off" polarized potential, or native potential.

5.9.3 Galvanic anode ground bed current output and polarity.

5.9.4 Structure-to-electrolyte potentials at each known buried MPLX and metallic foreign structure crossings.

5.9.5 Structure-to-electrolyte and casing-to-electrolyte potentials at all casings.

5.9.6 Structure-to-electrolyte potentials, current flow, and polarity at interference bonds.

5.9.7 Isolation effectiveness and On/Off readings on both sides of the isolation device. For routine checking of isolation devices, use an RF Insulator Checker instrument. The status of the insulator shall be indicated in the Insulator Status field in PCS. A potential difference of at least 100mV across the flange is also to be considered a valid test of insulator effectiveness.

5.9.8 AC potentials at every test point location. AC monitoring for induced AC from High Voltage Power Lines shall be in accordance with OPS-STD-0025.

5.9.9 Test points for new facilities shall be added to the survey in PCS.

5.10 Analyzing the Survey

5.10.1 All structure-to-electrolyte potentials shall be evaluated with regard to criteria and limits.

5.10.2 All survey test points not read on the survey shall be listed as deficiencies.

5.10.3 All monitored galvanic anode outputs shall be evaluated.

5.10.4 All known interference shall be evaluated.

5.10.5 All isolation devices shall be evaluated for adequate insulating qualities.

5.10.6 Rectifier(s) and/or any other cathodic protection current sources shall be evaluated for required output.

5.10.7 All structure-to-electrolyte potentials at foreign crossings shall be evaluated for interference conditions. Any substantial change at the crossing shall be evaluated. If interference is suspected, the crossing shall be listed as a deficiency and an interference test scheduled. The deficiency shall be noted in the technician's comments field in the Allegro Field PC.

5.10.8 All casings, supports, and valve boxes shall be evaluated for isolation. Testing of suspected shorts may be scheduled for a later time.

5.10.9 AC potentials shall be evaluated to determine magnitude and cause. AC potentials above 15 VAC are a potential safety concern, shall be listed as deficiencies unless otherwise approved and documented by the Regional Corrosion Control Team Lead or Engineer. Unapproved locations shall have prompt remediation if necessary.

5.10.9.1 The appropriate operator shall be notified if AC potentials above 15 VAC are found on foreign pipelines.

5.10.10 All unexplained indications of current pick-up or discharge that indicate a false reading or possible damage to the pipeline shall be evaluated to determine cause.

5.11 Documenting the Survey

5.11.1 When an annual survey has been completed and entered into the PCS database, that survey shall be promptly submitted to the Regional Corrosion Control Team Lead or Engineer for analysis.

5.12 Maintaining the Annual Survey Database

5.12.1 All pipeline facilities shall be set up in the PCS database. Facilities shall be located in the proper hierarchy.

5.12.2 Each reading location shall be entered under the proper pipeline segment. Reading locations include test stations, rectifiers, interference bonds, ground beds, and marine structures owned by MPLX.

5.12.3 It is recommended that test points use milepost/station numbers for identification. Mile post/station numbers can be corrected. During the Annual Survey when a feature such as a test point, rectifier, etc. is found to be incorrectly designated, change it to the correct value. If the milepost/station number change is at a rectifier, correct it on the appropriate monitoring form and notify the Regional Corrosion Control Team Lead or Engineer.

5.12.4 Quite often the casing vent is not directly above the end of the casing. The vent may be "doglegged" or extended, either back over the casing, away from the end of the casing, or to the side of the casing. The casing readings are to be taken over the pipeline one to three feet from the end of the casing. This may not be at the vent pipe.

5.12.5 Casing end locations, if not known, shall be located with a pipe locator and its location noted in the permanent comments of the casing vent test point.

5.12.6 The required readings for each reading location shall be made active.

5.12.7 Corrections, deletions, or additions can be made to the Description Section. The Description Section is intended to give information to the person making the survey, not to the person(s) reading the resulting printout.

5.12.8 For many test points, GPS or special instructions are necessary for the person conducting the survey to know how to find the test points. This is true for test points on MPLX pipelines but is especially for test points on foreign lines. Include these special instructions in the appropriate database field.

5.12.9 Data from retired or abandoned facilities SHALL NOT be deleted. Approved methods for making data inactive or archiving data shall be used. There are numerous circumstances that may require deleting an individual data set from a database. This might be the removal of a sales station and its associated piping, destruction of a test lead when land is converted from pasture to cultivation or housing, removal of a casing or removal of a foreign line. The data containing the information is not to be deleted but shall be converted to an inactive test point. This will maintain the test point's history and assist in documentation. A large group of points can be moved to another section of the hierarchy and made inactive. The data for a reference point or group of points cannot be deleted from the database or deactivated from the database without the Regional Corrosion Control Team Lead or Engineer's approval.

5.12.10 The technician shall make notes in the comments section of the read as to what needs to be removed. The Regional Corrosion Control Team Lead or Engineer shall create the required history records and remove the reading from the survey.

5.12.11 The technician shall maintain all the facilities for which they are responsible.

5.12.12 Structure-to-Electrolyte Potential Limits – Polarized potentials exceeding -1200 mV CSE for all grades of pipe shall be reported as deficiencies, unless justified in the Inspection Remarks field in PCS.

6.0 CLOSE INTERVAL SURVEYS (CIS)

6.1 General

6.1.1 Individuals performing close interval survey work shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

6.1.2 For new pipelines, the following circumstances shall be identified by the Regional Corrosion Control Team Lead or Engineer not more than 2 years after cathodic protection is installed:

- Number of Annual Test Point Inspection Locations that do not meet CP Criteria
- Number of Annual Test Point Inspection Locations with Suspected Foreign Pipeline Interference
- Most Recent CP System Current Outputs versus Rated Current Outputs

6.1.3 These circumstances shall be evaluated in order to determine when a close-interval survey or comparable technology is practicable and necessary to accomplish the below objectives:

- Assess the effectiveness of the CP system
- Provide baseline operating data
- Locate areas of inadequate protection levels
- Locate areas of possible coating deterioration
- Identify locations likely to be adversely affected by construction, stray currents, or other environmental conditions
- Select areas to be monitored periodically

6.1.4 The above analysis of the cathodic protection system shall be documented using OPS-STD-0020-FOR02 and stored with the appropriate pipeline documentation.

6.1.5 Close interval surveys, utilizing MPLX approved instrumentation, shall be conducted over cathodically protected pipelines at least once every five (5) years, but with intervals not exceeding seven (7) years. The interval for conducting close interval surveys on all other assets, if applicable, shall be determined by the Regional Corrosion Control Team Lead or Engineer based on past history, system goals, and risk analysis.

6.1.6 Close interval survey data entry and all applicable paperwork are to be completed and transmitted to the Regional Corrosion Control Team Lead or Engineer within sixty (60) days after completion date (or date final data is received from contractor) in order to provide timely analysis and remediation scheduling. The close interval survey data shall also be entered into the PCS database within sixty (60) days of receiving the survey data from the surveyor.

6.1.4.1 The Regional Corrosion Control Team Lead or Engineer shall be notified if any delays are anticipated.

6.1.7 Close interval survey data shall be retained per the retention schedule outlined in Appendix C of OPS-STD-0017.

6.2 Setting Up Notes

6.2.1 Prior to conducting a close interval survey, survey notes should be set up to assist the surveyor in defining locations. Sources of information would be alignment sheets, previous pipeline close interval surveys, and Annual Surveys. Enter the survey station number and a brief description of all features, which fall into one of the following categories:

1. Pipeline Contact – Locations where contact with the pipeline can be made such as valves, spans, drips, test leads, etc. Mileposts, engineering station

numbers, meter codes, and line IDs for each contact should be provided as necessary.

2. Skip Features – Pipeline locations where structure-to-electrolyte potentials cannot be observed such as aerial spans or cased crossings. These are to be defined by the upstream and downstream station numbers in order to define the length of the skip.
3. Reference Points – Permanent features along the pipeline noted, which shall serve as checkpoints to keep the survey on track. The more reference points used the better the correlation between potential reading locations and pipeline locations.
4. Crossings – All metallic pipelines whether foreign or other MPLX pipelines which cross the surveyed pipeline.
5. Casings – In addition, note the distance and direction of the casing vent(s) from the end(s) of the casing.
6. Interference Bonds – Connections with other structures through interference bonds shall be noted whether they are considered critical or non-critical. Current readings are required on interference bonds tied to or having an influence on the line being surveyed.
7. Current Sources – Sources of current which may have an influence on the line being surveyed. Examples are rectifiers and galvanic anode ground beds attached to the surveyed line or to a foreign line, which crosses or parallels the surveyed line.

6.3 Pipeline Contacts

6.3.1 Pipeline contacts are locations where contact with the pipeline can be made such as test leads, valves, spans, drips, risers, main line taps, etc.

6.3.2 Negative lead wires of a rectifier, galvanic anode ground bed lead wires, or interference bond station lead wires cannot be used as pipeline contacts to obtain structure-to-electrolyte potential readings. Metallic IR drops occur in these test leads, due to current flowing in the wire, and shall introduce an error into the structure-to-electrolyte potential reading. If a dedicated test lead has been installed at these locations, that lead can be used as a pipeline contact.

6.4 Test Points

6.4.1 This is the point over the centerline of the pipeline where the reference electrode (half-cell) shall be placed to take the potential reading. A pipeline locator is required to locate the center of the pipeline. The reference electrode shall be placed over the centerline of the buried piping.

6.4.2 Structure-to-electrolyte potentials taken through high resistance layers (blacktop, permafrost, macadam, etc.) may exhibit higher measurement error due to IR drop. When feasible, reference cell contact shall be made with the shared electrolyte.

6.4.3 It may be necessary to water the point of contact with the half-cell in areas of dry or high resistivity soils to lower the contact resistance of the half-cell to an acceptable level.

6.5 Reference Electrode Check

6.5.1 A reference electrode shall consist of a copper rod in a saturated copper-copper sulfate/distilled water solution. Other types of reference electrodes, such as silver-silver chloride, may be used in brackish or saltwater environments, but readings shall be converted to equivalent Cu-CuSO4 potentials.

6.5.2 A reference electrode check shall be performed, at a minimum, before starting each day and at the end of each day. Time, date, and reference cell ID shall be logged and recorded in OPS-STD-0020-FOR01.

6.5.2.1 Recommended guidance for testing and confirming reference electrode(s) are within tolerance can be located in TSCP-006 Cathodic Protection Survey Procedure 1 "Portable and Stationary Reference Electrode Calibration".

6.6 Survey Cycle

6.6.1 When an interrupted survey is performed, corresponding "On/Instant Off" potentials shall be logged at each half-cell position to allow for IR determinations. A slow cycle synchronized survey may be used with approval from the Regional Corrosion Control Team Lead or Engineer.

6.6.2 The normal survey interruption cycle of the current sources is 3-4 seconds "ON" and 1 second "OFF" for a total duty cycle of 4-5 seconds, beginning on the "OFF" cycle. Other survey cycles may be used with approval of the Regional Corrosion Control Team Lead or Engineer.

6.7 Survey Meters

6.7.1 All close interval surveys shall be performed using a multimeter, such as an American Innovations Allegro Field PC, that has been calibrated annually, not to exceed 15 months.

6.8 Survey Types

6.8.1 Normal close interval surveys are performed in ON/OFF mode. The survey data shall generate a printout with two data traces. One shall be the ON potential profile and the other shall be the OFF potential profile.

6.8.2 In areas with fluctuating potentials, the Telluric method shall be used. Slow cycle interruption of the current sources is recommended. The survey data shall generate a printout with two data streams. One shall be the moving (remote) potential profile and the other shall be the stationary (local) potential profile.

6.9 Skips

6.9.1 Skips are places on the pipeline where structure-to-electrolyte potentials cannot be measured. Explanations for the skips shall be included in the survey report.

6.9.2 If the area of the pipeline covered by the road surface is of sufficient length, the area shall be evaluated to determine if test holes or flush test stations are required to fully evaluate the section.

6.10 Survey Procedures

6.10.1 Recommended guidance for performing cathodic protection survey procedures can be located in TSCP-006 "Cathodic Protection Survey Procedures."

6.11 Minimum Survey Data Requirements

6.11.1 The minimum CIS survey data requirements include:

1. GPS coordinates at all potential readings.

2. On/Instant Off structure-to-electrolyte potentials along the pipeline alignment and at all pipeline test stations.
3. Far Ground (FG), Metal IR (MIR), and Near Ground (NG) potential measurements at each test station, if possible.
4. AC structure-to-electrolyte potentials at pipeline contacts when pipeline is in the vicinity of HVAC powerlines.
5. Influencing rectifier current and voltage outputs, if available.
6. On/Instant Off influencing galvanic anode ground bed currents where leads are accessible.
7. On/Instant Off interference bond currents influencing the area being surveyed.
8. On/Instant Off casing potential readings at all casing vent pipes. Casing vents can be doglegged in any direction and not represent the end of the casing. Note casing location from alignment sheet and start casing-to-electrolyte potential readings on the casing 1 to 3 feet from the end. Structure-to-electrolyte potential readings on the pipeline shall start a minimum of 1-foot from the end of the casing.
9. On/Instant Off MPLX and foreign structure structure-to-electrolyte potentials at all foreign crossings with test leads.
10. An engineering station and description entered for all features or reference points.
11. The upstream and downstream station numbers and descriptions of all skips.
12. On/Instant Off structure-to-electrolyte potentials are to be recorded over all drip blow-down lines connected to and in the area of the line being surveyed. Determine if the drip blow-down lines are isolated by taking near and far ground potential readings.
13. On/Instant Off structure-to-electrolyte potentials are to be taken at all isolation devices connected to the mainline at a tap, lateral, or inserted in the mainline.
14. On/Instant Off structure-to-electrolyte potentials on both sides of an isolation device.
15. On/Instant Off structure-to-electrolyte potentials across an isolation device.
16. Pipe depth measurements shall be performed using a pipe locator and recorded as part of the survey, unless otherwise specified by the Regional Corrosion Control Team Lead or Engineer. The following measurement interval is recommended:
    a. Pipe depth measurement every 100 feet along the alignment of the pipeline.
17. In addition to the above pipe depth measurements, a probe reading shall be taken and recorded at least once every half mile to confirm the pipe locator readings.
18. Soil resistivity measurements may be performed and recorded as part of the survey. The following measurement interval is recommended:
    a. Soil resistivity measurement (representing the soil at the depth of the pipe) every mile along the alignment of the pipeline.

6.12 Analyzing the Survey

6.12.1 Download survey information from the survey instrument to the computer, then analyze the data for any area(s) in need of remedial correction or future monitoring.

6.12.2 Edit the data to correct information that was omitted or improperly entered during the survey. Examples are incorrect or omitted station numbers, missing reference points, etc.

6.12.3 Graph the survey data for analysis. Indicate all irregularities, skips, low potential areas, etc. on the graph. Irregularities and low potential areas shall be indicated on the graph by noting their potential values and beginning and ending station plus. Skips shall be noted on the graph by beginning and ending station plus.

6.12.4 AC potential readings shall be evaluated as to magnitude and cause. AC potentials above 15 VAC shall be listed as deficiencies and shall have prompt remediation unless otherwise approved by the Regional Corrosion Control Team Lead or Engineer.

6.12.5 All foreign crossings shall be evaluated for interference. A dip in MPLX piping potential at a crossing shall be evaluated and, if necessary, assigned an immediate priority for correction. A positive potential on MPLX piping shall have an immediate plan in place for correction or investigation.

6.12.6 Isolation devices shall be checked for proper operation.

6.12.7 Rectifier and other impressed current source settings shall be evaluated, and new minimum current requirements shall be set as required for each unit.

6.12.8 All unexplained indications of current pickup or discharge shall be evaluated as to cause.

6.12.9 All structure-to-electrolyte potential readings shall be evaluated for profile irregularities, which may or may not be below criteria. These shall be tabulated as part of the survey and monitoring assigned to them.

6.12.10 List all skips where the potentials cannot be observed, such as cased piping or spans. The areas (description, beginning station, ending station, reason skipped) are to be listed on the summary sheet.

6.12.11 Skips where a potential survey is not normally performed, such as channels, marsh, swamps, and large water crossings, are also to be listed on the summary letter. These skips shall be listed as deficiencies unless prior approval is received from the Regional Corrosion Control Team Lead or Engineer.

6.12.12 Skips, which do not fall into either of the aforementioned categories, are to be listed as a deficiency in the survey, which requires a follow-up close interval survey before the close interval survey is considered complete. Exceptions exist for areas of uncased paved roads (less than 51 feet wide), sidewalks, residential driveways, etc. that meet the following criteria. These can be listed as a group on the summary sheet. If they do not meet the criteria, they are to be listed as a deficiency.

1. If the potential profile is essentially level and the lowest reading structure instant off at either edge of the pavement is no lower than 900 mV, then no further action is required.

2. If the potential profile declines slightly (25 mV drop) from the ROW line to the edge of the pavement and the structure instant off reading at the edge is no lower than 950 mV, then no further action is required.
3. If the potential profile declines significantly (50 mV drop) from the ROW line to the edge of the pavement and the structure instant off reading at the edge is no lower 1000 mV, then no further action is required.
4. If the potential profile does not meet any of these criteria, then the area is to be entered on the deficiency list and efforts shall be made to drill through the pavement to take structure-to-electrolyte potentials to verify the level of cathodic protection. The Regional Corrosion Control Team Lead or Engineer shall determine the interval between readings based on past history, current levels of protection adjacent to the skip area, and risk management.

6.12.13 Skips wider than 51 feet are to be evaluated as to the need to drill or install flush mounted test stations to verify the level of cathodic protection. In most cases, these areas are to be listed as deficiencies and efforts shall be made to take the necessary action to obtain the readings. The Regional Corrosion Control Team Lead or Engineer shall determine the interval between readings based on past history, current levels of protection adjacent to the skip area, and risk management.

6.12.14 Structure-to-Electrolyte Potential Limits – Polarized potentials exceeding -1200 mV CSE for all grades of pipe shall be reported as deficiencies, unless justified by appropriate documentation to the Regional Corrosion Control Team Lead or Engineer.

6.13 Tabulating Irregularities and Calculating Limits

6.13.1 The following is a procedure for monitoring irregularities (dips, changes in profile, peaks, etc.) found by close interval survey. The procedure correlates the minimum (or maximum) structure-to-electrolyte potential at a remote site to an annual survey reading at a test station. This provides a "flag," which can identify possible low potential areas remote from reading sites when conducting the annual survey. If a limit is broken, the remote site can then be surveyed to ensure compliance with criteria.

6.13.2 Analyze the pipeline close interval survey profile. This involves scanning the profile pages identifying the irregularities.

6.13.3 All structure-to-electrolyte potentials below or above criteria shall be listed in two places. First, an "Exception Table" shall be generated from final survey data for each run, listing by station number all areas above and below criteria or skipped.

6.13.4 Emphasis shall be placed on the following concepts:

1. Look for irregularities and high or low potential areas.
2. An irregularity exists when the potential drop and rise occurs within the prescribed distance.
3. A long slow potential drop or a long slow rise may not be an irregularity.
4. If there is doubt or reason to treat the area as an irregularity, then call it an irregularity and list it in the notes as such.

6.13.5 It is not necessary to define the exact length or contour of an irregularity, only the approximate 100 feet in which the low potential occurs.

6.13.6 The profiles shall be studied carefully in order to identify and tabulate the irregularities, skips and, low potential areas.

6.13.7 The pipeline contact becomes the control point. Use the control point for all calculations.

6.14 Submitting the Survey

6.14.1 The close interval survey remote monitoring information shall be added to the Annual Survey prior to the next Annual Survey due date.

6.14.2 The surveyor shall list each of the following deficiencies individually, as possible:

1. All areas where applicable criteria were violated.
2. All locations where the installation or repair of a test lead is necessary.
3. All areas where interference testing is necessary.
4. Skips requiring explanation and a follow-up re-survey at a later date.
5. Uncased paved roads (less than 51 feet wide) and/or several short-paved areas such as sidewalks and residential driveways that did not meet the criteria.
6. Each point of X-60 or greater pipe that is the Structure-to-Electrolyte Potential Limit.

6.14.3 The surveyor shall clearly identify each and every area or point of deficiency by providing the following:

1. Milepost (calculated from beginning station number).
2. Beginning and ending survey station numbers.
3. Length of low potential area or identification as a local.
4. Lowest or highest value of structure-to-electrolyte potential recorded.
5. Features, such as I-10, Pacific RR, MLV 55-3, Fwy 91, etc.

6.14.4 Cause of Deficiency: For each item listed, the surveyor shall provide a brief evaluation of the possible cause of the deficiency.

6.14.5 Recommended Corrective Measures: A corrective measure shall be included for each and every listing in the deficiency statement.

1. If an individual corrective action is intended to correct several deficiencies, then it needs to be listed only once, but shall be clear which deficiencies are corrected.
2. Corrective measures can include maintenance functions such as repair coating, clear shorted casing, install test lead(s), replace faulty insulators, etc. They can include operational functions such as conduct an interference test, perform a Follow-up Survey, etc.
3. Corrective measures for X-60 or greater pipe can include installing bias, lowering rectifier output with approval from the Regional Corrosion Control Team Lead or Engineer, relocating ground beds, etc.

6.14.6 Follow-up Survey Accomplished: Clearly identify each previously listed deficiency for which follow-up was accomplished by the survey being submitted. Each listing shall provide the following:

1. Milepost as carried on the original deficiency list.
2. Beginning and ending survey station numbers.
3. Date First Reported – use the earliest date if the deficiency has been reported repeatedly.
4. Date corrective measure completed.
5. Remarks if still deficient – Provide a description.

6.14.7 Close interval Survey Summary Sheet: Attach a letter summarizing the close interval survey. Include the following:

1. Rectifiers, galvanic ground beds, and interference bond stations by location, name, and DC output that were interrupted each day of the survey.
2. Extents of areas surveyed, with areas skipped clearly delineated.
3. Weather conditions.
4. Soil conditions during the survey.

6.15 Follow-Up Resurvey

6.15.1 The follow-up close interval resurvey is used to verify that deficiencies have been corrected.

6.15.2 Sections of pipeline in which cathodic protection deficiencies were revealed as part of the CIS hall have a follow-up resurvey performed within one year, not to exceed 15 months, of the completion of the corrective measures performed from that survey.

6.15.3 Deficiencies can be classified into three categories:

1. Low potential areas.
2. Repair areas – areas such as a temporary repair, installation of a manifold, leak repair, anomaly dig site, recoating, or pipe replacement.
3. Skip areas from CIS – Skip from CIS where the survey was interrupted across areas that could have been surveyed.

6.15.4 The resurvey shall be submitted in a similar manner as the described method above.

6.16 Special Surveys

6.16.1 If specialized surveys based on CIS techniques are performed (to identify Telluric effects, AC, or other influences), best practices and techniques as determined by the responsible person shall govern the testing.

7.0 SURVEY RECORD KEEPING

Table 2 Survey Record Keeping

Record	Owner	Location
Annual CP Survey Data	Regional Corrosion Control Team Lead or Engineer	PCS Database
CIS Survey Data	Regional Corrosion Control Team Lead or Engineer	PCS Database

MPLX	Reference Electrode Calibration Form	OPS-STD-0020-FOR01	
	FORM	Page 1 of 1	
		DATE: 4/1/2021	Rev: 0

Survey	
Meter / Serial #	Meter Calibration Date

Reference Electrode ID	Potential Difference Between Field Reference Electrode and Calibrated Reference Electrode (mV)	Date	Tested By

MPLX	Close Interval Survey Determination for New Pipelines	OPS-STD-0020-FOR02	
	FORM	Page 1 of 3	
		DATE 4/1/2021	Rev 0

PIPELINE INFORMATION			
Pipeline Name		County, State	
Pipeline Product		CP System In-Service Date	
Pipeline Length		Pipeline Diameter	
Pipeline GPS Start		Pipeline GPS End	

MOST RECENT CP SYSTEM INSPECTIONS
(Attach PCS Report or Fill Out Below Table)

CP System Name	MP	Inspection Date	Voltage (DC)			Amperage (DC)			Tap Settings						Lat	Long
									Coarse			Fine				
				of			*of*			*of*			*of*			
				of			*of*			*of*			*of*			
				of			*of*			*of*			*of*			

(Most Recent Settings per Location)

MOST RECENT CP TEST STATION INSPECTIONS (Attach PCS Report or Fill Out Below Table)
Table on Next Page

CLOSE INTERVAL SURVEY SCHEDULING			
Circumstances			
Annual Test Point Inspection Locations that do not meet Cathodic Protection Criteria		*of*	
Annual Test Point Inspection Locations with Suspected Foreign Pipeline Interference		*of*	
Other:			
Proposed CIS Timeframe			
☐ Perform initial CIS in ____ years from documentation of LO-10.016-FOR02 form (not to exceed 5 years from the CP System In-Service Date)			
☐ Perform initial CIS in 5 years from the CP System In-Service Date			

Signature		Date	
Name		Title	

MPLX	Close Interval Survey Determination for New Pipelines	OPS-STD-0020-FOR02	
	FORM	Page 2 of 3	
		DATE 4/1/2021	Rev 0

CLOSE INTERVAL SURVEY SCHEDULING
Additional Remarks

MPLX	Close Interval Survey Determination for New Pipelines	OPS-STD-0020-FOR02	
	FORM	Page 3 of 3	
		DATE 4/1/2021	Rev 0

MOST RECENT CP TEST STATION INSPECTIONS
(Attach PCS Report or Fill Out Below Table)

Location Name	MP	Inspection Date	Structure P/S (mV)	Structure IRF (mV)	Native (mV)	Foreign P/S (mV)	Foreign IRF (mV)	Inspection Remarks	Lat	Long

(Most Recent Settings per Location)

	Operating Standard	OPS-STD-0021	
MPLX	Cathodic Protection Test Point Monitoring and Maintenance	Page 1 of 4	
		DATE: 4/1/2021	Rev: 0

Contents

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for the inspection and mitigation of external corrosion through the use of cathodic protection for pipelines (e.g. valve site) and facilities (e.g. tanks, piping, vessels, etc.) to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life for the asset.
- Standardization of survey procedures and inspection requirements as they pertain to the mitigation of external corrosion through the use of cathodic protection.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard

2.2 Industry Codes and Standards

- NACE SP0169-2007 Control of External Corrosion on Underground or Submerged Metallic Piping

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

2.4 Other

- TSCP-006 Cathodic Protection Survey Procedures

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Cathodic Protection	A technique to control corrosion of a metal surface by making it the cathode in an electrochemical cell.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Electrolyte	A medium through which electrically charged particles (ions) may travel. Typically, soil, water, or product in this application.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
PCS	Pipeline Compliance System.
Reference Electrode	A device whose open circuit potential is constant under similar conditions of measurement.
Stray Current	Current flowing through paths other than the intended circuit.
Structure-to-Electrolyte Voltage (Also Structure-to-Soil Potential or Pipe-to-Soil Potential)	The voltage difference between a metallic structure and reference electrode in contact with a shared electrolyte.
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.

4.0 MONITORING

4.1 Individuals performing annual survey work shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

4.2 Cathodic protection monitoring and maintenance data shall be documented in the PCS database within sixty (60) days of the survey completion date.

4.3 Cathodic protection monitoring and maintenance data shall be retained per the retention schedule outlined in Appendix C of OPS-STD-0017.

5.0 TEST POINT SURVEYS

5.2 Test point surveys shall be performed annually, not to exceed 15 months.

5.3 Recommended guidance for performing DC structure-to-electrolyte potential measurements can be located in TSCP-006 Cathodic Protection Survey Procedure 4 "Direct Current (DC) Structure-to-Electrolyte Potential Testing".

5.4 Recommended guidance for performing AC structure-to-electrolyte potential measurements can be located in TSCP-006 Cathodic Protection Survey Procedure 5 "Alternating Current (AC) Structure-to-Electrolyte Potential Testing".

6.0 INSTALLATION AND MAINTENANCE OF TEST POINTS

6.1 Test leads shall be installed along a pipeline as follows:

6.1.1 Locate the leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.

6.1.2 Provide enough looping or slack so backfilling shall not unduly stress or break the lead and the lead shall otherwise remain mechanically secure and electrically conductive.

6.1.3 Prevent lead attachments from causing stress concentrations on pipe.

6.1.4 For leads installed in conduits, suitably insulate the lead from the conduit.

6.1.5 At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

6.2 Test leads shall be maintained in a condition that enables electrical measurements to be obtained to determine whether the location is meeting the criteria for cathodic protection. If a test lead is found defective and there are no other working test leads to make a potential measurement at the test station, all efforts will be made to repair the test station prior to the next scheduled inspection, although there may be situations in which we will exceed that frequency.

6.3 If it is found the wire connecting the pipeline to the test station is broken and there are sufficient test stations located near this station (not to exceed 5 miles), then this station may be deactivated with approval from the Regional Corrosion Control Team Lead or Engineer.

6.4 Test Station replacements or additions shall be documented in the PCS database.

7.0 INSTRUMENTATION AND MEASUREMENT GUIDELINES

7.1 Accurate cathodic protection electrical measurements require proper selection and use of instruments. Structure-to-electrolyte potential, voltage drop, potential difference, and similar measurements require instruments that have appropriate voltage ranges. The user shall know the capabilities and limitations of the equipment, calibration of equipment, follow the manufacturer's instruction manual, and be skilled in the use of electrical instruments. Failure to select and use instruments correctly may cause personal harm or errors in cathodic protection measurements.

7.2 Instruments used for structure to electrolyte potential measurements shall be calibrated to or checked against a NIST traceable standard on an annual basis.

7.3 To measure structure-to-electrolyte potentials accurately, a digital voltmeter shall have a high input impedance (at least 10 MΩ) compared with the total resistance of the measurement circuit.

8.0 SURVEY RECORD KEEPING

Table 2 Survey Record Keeping

Record	Owner	Location
Annual CP Survey	Regional Corrosion Control Team Lead or Engineer	PCS Database

MPLX	Operating Standard	OPS-STD-0022	
	Cathodic Protection Rectifier and Interference Bond Monitoring and Maintenance	Page 1 of 5	
		DATE: 4/1/2021	Rev: 0

Contents

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for the monitoring and maintenance of cathodic protection rectifiers and interference bonds installed on pipelines (e.g. valve site) and facilities (e.g. tanks, piping, vessels, etc.) to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life for the asset.
- Standardization of survey procedures and inspection requirements as they pertain to the mitigation of external corrosion.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021
NOTICE: The information contained herein is the confidential property of MPLX unless another source is indicated. This material is subject to return on demand and must not be disclosed or reproduced without prior written consent by a duly authorized representative of MPLX.			
OPS-STD-0022 Cathodic Protection Rectifier and Interference Bond Monitoring and Maintenance			

2.2 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

2.3 Other

- TSCP-006 Cathodic Protection Survey Procedures

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Cathodic Protection	A technique to control corrosion of a metal surface by making it the cathode in an electrochemical cell.
Continuity Bond	A metallic connection that provides electrical continuity between MPLX assets for the purpose of facilitating cathodic protection.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Critical Interference Bond	A metallic connection designed to control electrical current interchange between an MPLX asset and a Foreign Structure in a shared electrolyte, which if disconnected, will cause detrimental effects to an MPLX asset.
Electrical Isolation	The condition of being substantially electrically separated from other metallic structures and the environment.
Foreign Structure	Any structure that is not owned by MPLX.
Half Cell Reference Electrode	See Reference Electrode.
Impressed Current	Direct current supplied by a power source external to the electrode system.
Inspector/ Person in Charge (PIC)	An MPLX appointed engineer or inspector.
IR Drop	The voltage difference between a structure and reference electrode due to transient current flow in a conductive medium (soil, water, etc.).
Interference Bond	A metallic connection designed to control electrical current interchange between an MPLX asset and a Foreign Structure.
Isolation	See Electrical Isolation.
Line Current	The direct current flowing on a pipeline.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
Non-Critical Interference Bond	A metallic connection designed to control electrical current interchange between an MPLX asset and a Foreign Structure in a shared electrolyte, which if disconnected, shall cause no detrimental effects to an MPLX asset.
PCS	Pipeline Compliance System.
Reference Electrode	A device whose open circuit potential is constant under similar conditions of measurement.
Reverse Current Switch	A device that prevents the reversal of direct current through a metallic conductor.

Table 1 Definitions

Term	Description
Shared Electrolyte	Electrolyte in contact with both the electrode and the structure.
Stray Current	Current flowing through paths other than the intended circuit.
Stray Current Corrosion	Corrosion resulting from current flowing through paths other than the intended circuit.
Structure-to-Electrolyte Voltage (Also Structure-to-Soil Potential or Pipe-to-Soil Potential)	The voltage difference between a metallic structure and reference electrode in contact with a shared electrolyte.
Structure-to-Structure Voltage (Also, Structure-to-Structure Potential)	The difference in voltage between metallic structures in a common electrolyte.
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.

4.0 MONITORING

4.1 Individuals performing annual survey work shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

4.2 Rectifier and interference bond readings shall be documented in the PCS database within sixty (60) days of the survey completion date. In addition to routine monitoring, the following shall be documented:

1. Adjustments.
2. Unit maintenance and repairs.
3. Ground bed maintenance/addition.
4. GPS coordinates of each rectifier and interference bond.

4.3 Rectifier and interference bond readings shall be retained per the retention schedule outlined in Appendix C of OPS-STD-0017.

5.0 RECTIFIER SURVEYS

5.1 Rectifier surveys shall be performed 6 times per calendar year, not to exceed 2.5 months, and after installing a new rectifier, installing a new or partial replacement ground bed and making rectifier repairs.

5.2 Recommended guidance for performing DC rectifier voltage and amperage output testing can be located in TSCP-006 Cathodic Protection Survey Procedure 14 "Rectifier Operation, Measurements, Maintenance and Commissioning".

5.3 Rectifier survey records shall consist of:

1. A measurement across the positive and negative leads for voltage meter reading.
2. A measurement across the shunt for the amperage meter reading.
   - Amperage from Foreign operator negative returns, if present, shall be measured and recorded as part of the bimonthly/annual surveys.
3. Recording of the Taps Settings, if present.
   - Recording the Taps Settings as "Same" shall not be accepted.
4. Recording the name of the Technician who performed the measurements.

5.4 Remote monitoring units (RMUs) can be utilized to obtain rectifier survey data, yet each rectifier shall be inspected on-site at least once annually, not to exceed 15 months, to verify proper operation of the RMU and to perform a visual integrity check of the rectifier.

5.5 If a rectifier is not preforming correctly, it shall be repaired, or replaced, within 2.5 months of the discovery, unless approval is given from the Regional Corrosion Control Team Lead to keep the unit turned off.

6.0 INTERFERENCE BOND SURVEYS

6.1 Critical interference bond surveys shall be performed 6 times per calendar year, not to exceed 2.5 months.

6.2 Non-critical interference bond surveys shall be performed on an annual basis, not to exceed 15 months.

6.3 Bonds across insulators utilized by MPLX to facilitate cathodic protection are known as continuity bonds and are not required to be tested as interference bonds.

6.4 Recommended guidance for performing interference bond testing can be located in TSCP-006 Cathodic Protection Survey Procedure 16 "Electrical Bond Testing".

6.5 Interference bond survey records shall consist of:

- A measurement across the shunt for the amperage across the interference bond.
- Recording of the polarity of the amperage across the interference bond.
- Recording the name of the Technician who performed the measurements.

6.6 Remote monitoring units (RMUs) can be utilized to obtain interference bond survey data, yet each interference bond shall be inspected on-site at least once annually, not to exceed 15 months, to verify proper operation of the RMU and to perform a visual integrity check of the interference bond.

6.7 If a critical interference bond is not preforming correctly, it shall be repaired within 2.5 months of the discovery, unless approval is given from the Regional Corrosion Control Team Lead to disconnect the interference bond.

7.0 CLASSIFICATION OF INTERFERENCE BONDS

7.1 The as-found interference bond current shall already be recorded, following the steps listed above.

7.2 While the interference bond is connected, a structure-to-electrolyte potential of the MPLX test leads located at the interference bond location shall be measured. Record this data with the cathodic protection current source both On and momentarily interrupted (Instant-Off).

7.3 Disconnect the interference bond and obtain another structure-to-electrolyte potential of the MPLX asset test leads located at the interference bond location, with the reference cell in the same location. Record this data.

7.4 If the MPLX asset structure-to-electrolyte potentials in the Instant-Off mode are more positive than -850mV with the interference bond disconnected, further testing shall be performed per specified below.

7.5 Further Testing – Shut off all cathodic protection sources affecting the area of test. Allow the structure potential to depolarize at least 100 mV more positive than the Instant-Off potential with the reference electrode in the same location as in section 9.4 and with the interference bond disconnected. If 100 mV shift in potential from the Instant-Off potential is obtained, then the interference bond would not be considered critical. If available, existing depolarized potential data can be used to evaluate against the Instant-Off potential.

7.6 If any of the above test criterions cannot be achieved, then the interference bond is defined as critical.

8.0 SURVEY RECORD KEEPING

Table 2 Survey Record Keeping

Record	Owner	Location
Rectifier and Interference Bond Survey Data	Regional Corrosion Control Team Lead	PCS Database

	Operating Standard	OPS-STD-0023	
MPLX	Electrical Isolation Monitoring and Maintenance	Page 1 of 4	
		DATE: 4/1/2021	Rev: 0

Contents

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for inspection and remediation of electrical isolation for pipelines (e.g. valve site) and facilities (e.g. tanks, piping, vessels, etc.) to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life for the asset.
- Standardization of survey procedures and inspection requirements as they pertain to the inspection and remediation of electrical isolation.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- OPS-STD-0020 Aboveground Cathodic Protection Surveys

- OPS-STD-0023-FOR-01 Electrical Short Remediation Plan Form

2.2 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

2.3 Other

- TSCP-006 Cathodic Protection Survey Procedures

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Arcing	An electric arc, or arc discharge, is an electrical breakdown of a gas that produces an ongoing electrical discharge. The current through a normally nonconductive medium such as air produces a plasma; the plasma may produce visible light.
Cathodic Protection	A technique to control corrosion of a metal surface by making it the cathode in an electrochemical cell.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Electrical Isolation	The condition of being substantially electrically separated from other metallic structures and the environment.
Electrolyte	A medium through which electrically charged particles (ions) may travel. Typically soil, water, or product in this application.
Isolation	See Electrical Isolation.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
PCS	Pipeline Compliance System.
Reference Electrode	A device whose open circuit potential is constant under similar conditions of measurement.
Structure-to-Electrolyte Voltage (Also Structure-to-Soil Potential or Pipe-to-Soil Potential)	The voltage difference between a metallic structure and reference electrode in contact with a shared electrolyte.
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.

4.0 NEED FOR ELECTRICAL ISOLATION

4.1 Where present, carrier pipe shall be installed to be electrically isolated from pipeline casing.

4.2 An electrical isolation flange kit shall not be installed without the approval from the Regional Corrosion Control Team Lead or Engineer.

4.1.1 Not all locations require an electrical isolation and an electrical isolation could cause adverse effects for the cathodic protection systems.

4.3 If a pipeline is designed to be electrically continuous but is supported by another metallic structure in contact with soil or groundwater, the pipeline shall be electrically isolated from that structure. The isolating supports shall prevent damage to the pipeline coating and shall accommodate relative movement, vibration and temperature differential.

5.0 MONITORING

5.1 Individuals performing annual survey work shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

5.2 Testing data shall be entered into the PCS database within sixty (60) days of the testing completion date.

5.3 Electrical isolation testing data shall be retained per the retention schedule outlined in Appendix C of OPS-STD-0017.

6.0 ELECTRICAL ISOLATION SURVEYS

6.1 Pipeline Casings

6.1.1 Pipeline casings shall be surveyed annually, not to exceed 15 months.

6.1.2 If a casing is determined to be electrically shorted to a pipeline, it shall either be classified as a direct (metallic) short or an electrolytic (electrolyte) coupling.

6.1.3 Recommended guidance for performing casing electrical isolation testing can be located in TSCP-006 Cathodic Protection Survey Procedure 10 "Pipe to Casing Electrical Isolation Testing".

6.2 Isolation Flange Kits

6.2.1 Isolation flange kits shall be surveyed annually, not to exceed 15 months.

6.2.2 If the potential difference across an isolation flange kit is less than 100 mV, a radio frequency insulator tester (RF-IT) shall be used to determine whether or not the isolation flange kit is electrically shorted.

6.2.3 Recommended guidance for performing electrical isolation flange kit testing can be located in TSCP-006 Cathodic Protection Survey Procedure 11 "Electrical Isolation Flange Kit Testing".

7.0 MONITORING AND REPAIRS

7.1 Pipeline Casings

7.1.1 If a casing and pipeline are determined to be electrically shorted through a direct (metallic) short, a remediation plan to clear the short shall be documented within six months of the discovery per OPS-STD-0023-FOR-01.

7.1.2 If a casing and pipeline are determined to be electrically shorted through an electrolytic (electrolyte) coupling, a structure-to-electrolyte potential measurement shall be taken near each end of the casing.

7.1.2.1 If the structure-to-electrolyte potentials meet the protection criteria outlined in OPS-STD-0020, the casing shall continue to be monitored on an annual basis.

7.1.2.2 If the structure-to-electrolyte potentials do not meet the protection criteria outlined in OPS-STD-0020, a remediation plan to clear the coupling shall be documented within six months of the discovery per OPS-STD-0023-FOR-01.

7.2 Isolation Flange Kits

7.2.1 If an isolating flange kit is found to be electrically shorted and it causes the location to not meet cathodic protection criteria:

1. Trace out all gauge lines, tubing, electrical conduit, etc. for a potential electrical path around the isolation flange kit and check any inline isolation devices for proper operation using the radio frequency insulator checker.
2. Use an RF-IT, per manufacturer's instructions, to test each bolt for isolation. Replace any defective isolating sleeves or washers.
3. If the cause of the short cannot be located by the aforementioned methods, then a faulty electrical isolating gasket may be the cause. To repair, the joint will need to be disassembled and the defective isolating gasket replaced.
4. After the short is located and repaired, re-inspect to ensure the corrective action was successful.

7.2.2 If a shorted isolating flange kit cannot be fixed at the time of discovery, a remediation plan to clear the short shall be documented within six months of the discovery per OPS-STD-0023-FOR-01.

8.0 SURVEY RECORD KEEPING

Table 2 Survey Record Keeping

Record	Owner	Location
Annual Cathodic Protection Survey	Regional Corrosion Control Team Lead or Engineer	PCS

MPLX	Operating Standard	OPS-STD-0024	
	DC Interference Monitoring and Mitigation	Page 1 of 6	
		DATE: 4/1/2021	Rev: 0

Contents

List of Tables

1.0 INTRODUCTION

1.1 Purpose

This Standard establishes minimum requirements for the inspection and mitigation of direct current (DC) interference on pipelines (e.g. valve site) and facilities (e.g. tanks, piping, vessels, etc.) to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life for the asset.
- Standardization of work procedures and inspection requirements as they pertain to the inspection and mitigation of DC interference.

1.2 Scope

1.2.1 MPLX. This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- OPS-STD-0020 Aboveground Cathodic Protection Surveys
- OPS-STD-0024-FOR01 DC Interference Monitoring and Mitigation Form

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021

2.2 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

2.3 Other

- TSCP-006 Cathodic Protection Survey Procedures

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Anode	An electrode that is characterized by electron loss.
Ammeter	A measuring instrument used to measure the current in a circuit.
Amphoteric Metal	A metal that reacts in both acidic and alkaline environments.
Cathodic Protection	A technique to control corrosion of a metal surface by making it the cathode in an electrochemical cell.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Corrosion Control Coordinating Committee	A committee of Corrosion Control personnel from multiple pipeline companies.
Current Exchange Agreement	A negotiated interference bond that provides a benefit to one or both parties and is in effect only as long as both parties are in agreement.
Electrolyte	A medium through which electrically charged particles (ions) may travel. Typically soil, water, or product in this application.
Foreign Structure	Any structure that is not part of the subject structure.
Galvanic Anode	Typically a prepackaged assembly consisting of an active metal (Mg, Zn, etc.) in a moisture retaining backfill. Generally any metal which is more electrochemically active in a multi-metal system.
Impressed Current	Direct current supplied by a power source external to the electrode system.
Interference Bond	A metallic connection designed to control electrical current interchange between metallic systems.
Line Current	The direct current flowing on a pipeline.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
PCS	Pipeline Compliance System.
Reference Electrode	A device whose open circuit potential is constant under similar conditions of measurement.
Reverse Current Switch	A device that prevents the reversal of direct current through a metallic conductor.
Shared Electrolyte	Electrolyte in contact with both the electrode and the structure.
Stray Current	Current flowing through paths other than the intended circuit.
Stray Current Corrosion	Corrosion resulting from current flowing through paths other than the intended circuit.

Term	Description
Structure-to-Electrolyte Voltage (Also Structure-to-Soil Potential or Pipe-to-Soil Potential)	The voltage difference between a metallic structure and reference electrode in contact with a shared electrolyte.
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.

4.0 CONTROL OF INTERFERENCE CURRENTS

4.1 During corrosion control surveys performed under OPS-STD-0020, personnel shall be alert for electrical or physical observations that could indicate interference from a neighboring source during corrosion control surveys. Indications of interference are as follows:

1. Structure-to-soil potential changes on the affected structure caused by the foreign direct current source.
2. Changes in the line current magnitude or direction caused by the foreign direct current source.
3. Localized pitting in areas near to or immediately adjacent to a foreign structure.
4. Breakdown of protective coatings in a localized area near an anode bed or near any other source of stray direct current.

4.2 Appropriate tests shall be conducted to determine the cause in areas where interference currents are suspected. All affected parties shall be notified before tests are made for the purpose of determining a mitigation technique. Any one or combination of the following test methods shall be employed.

1. Measurement of structure-to-electrolyte potentials with recording or indicating instruments.
2. Measurement of current flowing on the structure with recording or indicating instruments.
3. Measurement of the variations in current output of the suspected source of interference current and correlations with measurements obtained in Sections 4.2.1 and 4.2.2 above.

5.0 INTERFERENCE BONDS

5.1 In the event that interference is present between our pipeline and a foreign operator’s pipeline, a Current Exchange Agreement may be established upon agreement of both companies. If established, the Regional Corrosion Control Team Lead or Engineer shall review all data, obtain Property Rights approval, and coordinate the establishment of any interference bond agreement.

5.2 No interference bond is to be installed or removed without an Interference Test being conducted and documented using OPS-STD-0024-FOR01. The completed form shall be stored in the “Corrosion Control” folder within the Documents Library and retained in accordance with Appendix C in OPS-STD-0017.

5.2.1 If an interference bond is lost for any reason, it shall be reinstalled as soon as possible upon detection, unless an Interference Test proves that the bond is no longer needed as per Section 9.3.

5.3 A precision resistance shunt should be installed in an interference bond test station to allow the current to be read without unhooking the interference bond or the interference bond current shall be read with a clamp on ammeter. If a precision shunt is not installed, the current is to be read with an ammeter, and the following procedure shall be used to keep any circuit conditions change to a minimum:

1. Hook the ammeter up across the terminals to the interference bonded structures first.
2. Disconnect the metallic connection between the structures.
3. Take the current reading.
4. Connect the structures.
5. Disconnect the ammeter.

6.0 TEST FACILITIES

6.1 Where feasible, test facilities shall be installed at underground foreign metallic pipeline crossings.

6.1.1 Additional interference tests sites may include:

1. Meter stations with insulating devices between MPLX structures and foreign structures.
2. Where pipelines run parallel in high resistivity soils and encounter an area of relatively low resistivity soils (ex. at a river crossing).

6.2 Interference test facilities shall include two wires for each structure, one wire for current and one wire for potential measurements.

1. Refer to the Foreign Company's color scheme for wire coloring of their structure, if they have no color scheme then MPLX's wire shall be white, if their color scheme matches MPLX then MPLX's wire shall be black.
2. The color of the test wires identified by structure shall be recorded on the appropriate company report and in the test station (or interference bond box) when the facilities are installed.

6.3 Wire connections to underground metallic structures shall be made by thermite welding or pin brazing. The connection shall be tested for mechanical strength and electrical continuity. All connections shall be coated with an approved coating system.

6.4 Attachments to, probe bar contact to, and excavation of foreign structures are at the discretion of the foreign structure owner and shall not be made by MPLX personnel. Probe bar contacts to MPLX structures for interference testing shall not be allowed unless the area is immediately excavated to repair coating damage.

7.0 MONITORING

7.1 All identified interference test stations (no bond) shall be evaluated during annual or close interval surveys and the status shall be recorded in the PCS database. Any detrimental indications of current pickup or discharge shall be evaluated as to its cause.

7.1.1 For underground foreign pipeline crossings, the foreign pipeline potentials shall be recorded in the Foreign P/S and Foreign IRF fields in PCS during a survey.

7.1.2 For aboveground foreign pipeline connections to MPLX piping that are electrically isolated though the use of an insulating flange kit, the foreign pipeline potentials shall be recorded in the Insulator P/S and Insulator IRF fields in PCS during a survey.

7.2 Where detrimental interference is suspected, a joint interference test shall be scheduled within 90 days of discovery.

7.3 If indications of interference are discovered that pose an immediate hazard to MPLX structure or affect an area where public safety is a concern, the Regional Corrosion Control Team Lead or Engineer shall be contacted immediately and shall determine if the installation of temporary corrective measures will be installed until definitive testing and remediation is completed.

7.4 Any area where MPLX readings indicate a positive potential shall be investigated and corrected within 12 months of the discovery date.

7.5 Written documentation of all requests for interference testing and responses shall be stored in the "Corrosion Control" folder within the Documents Library and retained in accordance with Appendix C in OPS-STD-0017.

7.5.1 Written documentation shall be by letter or email and shall contain the following information:

1. Location of area of concern.
2. Contact name.
3. Request for an exchange of cathodic protection operating history.

7.6 If the ownership of a foreign structure cannot be readily determined, then a reasonable effort shall be made to ascertain the ownership, especially if testing determines that MPLX's cathodic protection could be affecting the foreign structure.

7.7 If joint testing or installation of test leads is requested and the owner of the foreign structure does not respond in a timely manner, a registered letter shall be sent. The registered letter shall contain the same information as Section 7.5.1. The registered letter shall be kept for the life of the system. If there is no response, MPLX shall proceed as deemed necessary.

8.0 INTERFERENCE TESTING

8.1 Recommended guidance for performing DC interference testing can be located in TSCP-006 Cathodic Protection Survey Procedure 17 "Direct Current (DC) Interference Testing".

9.0 INTERFERENCE MITIGATION

9.1 General Methods for Resolving Interference Corrosion Problems

Interference problems are individual in nature and the solution shall be mutually satisfactory to the parties involved. The general methods, in no preferential order, are as follows:

1. Prevention of the pick-up or limitation of the flow of interfering current through a buried or submerged metallic structure.
2. Removal or relocation of interfering current source.
3. Counteraction of the effect of interfering current by means of cathodic protection.
4. Removal of the detrimental effects of interfering current from a buried metallic structure by means of a metallic conductor connected to the return (negative) side of the interfering current source. Before interference bonds are installed, approval shall be obtained from the affected parties.

9.2 Specific Methods of Resolving Interference Corrosion Problems

These methods may be used individually or in combination. The specific methods are:

1. Design and installation of interference bonds of proper resistance between the affected structures is a common technique for interference control. The interference bond electrically conducts interference current from an affected structure to the interfering structure and/or current source. Uni-directional control devices, such as diodes or reverse current switches, may be required in conjunction with interference bonds if fluctuating currents are present. These

devices prevent reversal of current flow. A resistor may be necessary in the interference bond circuit to control the flow of electrical current from the affected to the interfering structure. At the proper interference bond resistance, the discharge of interfering current from the structure to electrolyte is stopped. If cathodic protection exists on the interfering structure, the attachment of interference bonds can reduce the magnitude of protective voltage. Supplementary cathodic protection may then be required on the interfering structure to compensate for this effect. An interference bond may not perform properly in the case of a cathodically protected bare or poorly coated pipeline that is causing interference on a coated pipeline. An interference bond may increase the current discharge. Coating the bare pipe or installing local galvanic anodes on the coated pipe may reduce the interference effects.

2. Cathodic protection current can be applied to the affected structure at those locations where the interfering current is being discharged. This discharge shall usually occur at locations where the structures are in close proximity. Anodes shall be placed immediately adjacent to that portion of the affected structure that is discharging current. The source of cathodic protection current may be galvanic or impressed current anodes. The amount of cathodic protection current shall be adjusted to restore the original potential level.
3. Adjustment of the current output from mutually interfering cathodic protection rectifiers may resolve interference problems.
4. Relocation of the ground beds of cathodic protection rectifiers can reduce or eliminate the pickup of interference current on nearby structures.
5. Rerouting of proposed pipelines may avoid sources of interference current.
6. Properly located insulating fittings in the affected structure may reduce or resolve interference problems.
7. Application of coating to strategic area(s) may reduce or resolve interference problems by decreasing the circuit conductance.

9.3 Indications that Interference Problems Have Been Resolved

1. Restoration of the structure-to-electrolyte potentials on the affected structure to those values that existed prior to the interference.
2. Measurement of line currents on the affected structure to ensure that interference current is not being discharged to the electrolyte.

10.0 SURVEY RECORD KEEPING

Table 2 Survey Record Keeping

Record	Owner	Location
Bi-Monthly Critical Interference Bond Readings	Regional Corrosion Control Team Lead or Engineer	PCS Database
Annual CP Survey	Regional Corrosion Control Team Lead or Engineer	PCS Database

Contents

List of Figures

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for the inspection and mitigation of alternating current (AC) interference on pipelines (e.g. valve site) and facilities (e.g. tanks, piping, vessels, etc.) to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities)
- The intended service life for the asset.
- Standardization of survey procedures and inspection requirements as they pertain to the mitigation of external corrosion.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard

2.2 Industry Codes and Standards

- IEEE 80 Guide for Safety in Substation Grounding, 2000
- NACE SP0169-2007, Standard Practice, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" reaffirmed March 15, 2007
- NACE SP0177-2007 Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems, 2007
- CEN/TS 15280 (latest version) Evaluation of A.C. Corrosion Likelihood of Buried Pipelines – Application to Cathodically Protected Pipelines

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

2.4 Other

- TSCP-006 Cathodic Protection Survey Procedures
- NACE 35110-2010 AC Corrosion State-of-the-Art: Corrosion Rate, Mechanism, and Mitigation Requirements

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	**Description**
Alternating Current (AC)	An electrical current whose direction or polarity changes with time. The polarity or cycles are due to the alternating magnetic fields used in its generation. The time frequency cycle is also referred to as hertz. In North America, the common frequency is 60 hertz (cycles per second).
Anode	An electrode that is characterized by electron loss (oxidation).
Breakout Tank	A tank used to: ➢ Relieve pressure surges in a hazardous liquid pipeline system or ➢ Receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline
Capacitive Coupling	The influence of two or more circuits upon one another, through a dielectric medium such as air, by means of the electric field acting between them.
Cathodic Protection	A technique to control corrosion of a metal surface by making it the cathode in an electrochemical cell.
Continuity Bond	A metallic connection that provides electrical continuity.

Table 1 Definitions

Term	Description
Contractor	Company or business that agrees to furnish materials or perform specified services at a specified price and/or rate to MPLX.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Current Density	The current per unit area.
Electrical Isolation	The condition of being substantially electrically separated from other metallic structures and the environment.
Electrode Potential	The potential of an electrode as measured against a reference electrode.
Electrolyte	A medium through which electrically charged particles (ions) may travel. Typically soil, water, or product in this application.
Engineered Solution	A comprehensive investigation of the pipeline/transmission line interactions using actual operating parameters and commercially available software to model the predicted effects of the collocation/crossing and identify viable solutions.
Fault Current	A current that flows from one conductor to ground or to another conductor due to an abnormal connection (including an arc) between the two. A fault current flowing to ground may be called a ground fault current.
Ground	An electrical connection to earth.
Ground Potential Rise	Ground Potential Rise or Earth Potential Rise (as defined in IEEE (1) Standard 367) is the product of a ground electrode impedance, referenced to remote earth, and the current that flows through that electrode impedance. This occurs when large amounts of electricity enter the earth. This is typically caused when substations or high-voltage towers fault, or when lightning strikes occur (fault current). When currents of large magnitude enter the earth from a grounding system, not only does the grounding system rise in electrical potential, but so does the surrounding soil. The resulting potential differences causes currents to flow into any and all nearby grounded conductive bodies, including concrete, pipes, copper wires, and people.
Holiday	A discontinuity of coating that exposes the metal surface to the environment.
Impressed Current	Direct current supplied by a power source external to the electrode system.
Isolation	See Electrical Isolation.
Lightning	An electric discharge that occurs in the atmosphere between clouds or between clouds and the earth.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
Over-Voltage Protector (Surge Arrester)	A device that provides high resistance to direct current (DC) and high impedance to AC under normal conditions within the specified DC and AC threshold rating and "closes" or has a very low resistance and impedance during upset conditions.
Potential Gradient	Change in the potential with respect to distance.
PCS	Pipeline Compliance System.
Resistive Coupling	The influence of two or more circuits on one another by means of conductive paths (metallic, semi-conductive, or electrolytic) between the circuits.

Table 1 Definitions

Term	Description
Reverse Current Switch	A device that prevents the reversal of direct current through a metallic conductor.
Shared Electrolyte	Electrolyte in contact with both the electrode and the structure.
Shock Hazard	A condition considered to exist at an accessible part in a circuit between the part and ground or other accessible part if the steady-state open-circuit AC voltage is 15 V or more (root mean square [rms]). For capacitive build-up situations, a source capacity of 5 mA or more is recognized as a hazardous condition. For short-circuit conditions, the permissible touch-and-step voltages shall be determined in accordance with the methodology specified in accordance with IEEE 80,4 or equivalent standard.
Solid State DC Decoupler	Dry type of DC decoupling device comprising solid state electronics. The electrical characteristics of a solid-state decoupler are high resistance to low-voltage DC and low impedance to AC.
Step Potential or Step Voltage	The potential difference between two points on the earth's surface separated by a distance of one human step, which is defined as one meter, determined in the direction of maximum potential gradient.
Stray Current	Current flowing through paths other than the intended circuit.
Structure-to-Electrolyte Voltage (Also Structure-to-Soil Potential or Pipe-to-Soil Potential)	The voltage difference between a metallic structure and reference electrode in contact with a shared electrolyte.
Telluric Current	An electric current which moves underground or through the sea. The currents are primarily geomagnetically induced currents, which are induced by changes in the outer part of the Earth's magnetic field, which are usually caused by interactions between the solar wind and the magnetosphere or solar radiation effects on the ionosphere.
Touch Potential or Touch Voltage	The potential difference between a metallic structure and a point on the earth's surface separated by a distance equal to the normal maximum horizontal reach of a human (approximately 1.0 m [3.3 ft]).
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.

4.0 TRANSMISSION LINE INDUCED AC REQUIREMENTS

4.1 Pipelines

4.1.1 All existing pipelines shall be reviewed for crossings or collocations with an existing high voltage alternating current (HVAC) transmission line(s) (defined as 69 kV or higher). These areas shall be analyzed, and engineering solutions considered in accordance with Figure 2. In addition, an influence study shall be performed when:

- A new pipeline(s) is installed within 500-feet of an existing parallel HVAC transmission line(s).
- When a new HVAC transmission line(s) is installed within 500-feet of a parallel existing pipeline(s).

4.1.2 An evaluation of the possible risk to personnel safety for those working on the pipeline and possible pipeline corrosion damage shall take place whenever a pipeline is in close proximity to a HVAC transmission line. A mitigation system can be designed for those areas where potentials are above permissible limits as specified in the IEEE 80 and NACE SP0177. These Standards indicate mitigation is necessary in those cases where step or touch potentials are in excess of 15 V_{AC}.

4.1.3 It should be noted that the steady state 15 V_{AC} threshold (in the standards listed above) was established with personnel safety in mind and not with consideration of corrosion influences. Recent research and experience has shown that AC accelerated corrosion can occur in low resistivity soils at AC voltages well below this threshold, as shown in Figure 1.

4.1.4 Recommended guidance for performing AC interference testing can be located in TSCP-006 Cathodic Protection Survey Procedure 18 "Alternating Current (AC) Interference Testing"

4.1.5 The AC structure-to-electrolyte potential (V_{AC}) data collected during the annual CP surveys, per Table 2, shall be reviewed and based on the results, the following actions shall be taken:

1. **V_{AC} less than 5 volts:** Continue monitoring (loads in transmission lines can vary significantly within 24 hours periods and with seasonal conditions).
2. **V_{AC} between 5 and 15 volts:** Perform additional testing by measuring and recording the AC structure-to-electrolyte potential over a 24-hour period using a data logging instrument. If the AC structure-to-electrolyte potential is consistently over 5 volts, soil resistivity testing shall be performed to determine the resistivity of the soil at the depth of the pipe in the area next to the test station. Using Figure 1, the AC structure-to-electrolyte potential and soil resistivity shall be plotted to determine the estimated AC current density in which the area falls under. If the AC current density is above 20 A/m^2, a coupon shall be installed at the test station.

V_{AC} above 15 volts: Regional Corrosion Control Team Lead or Engineer shall be responsible for developing and submitting an engineered solution to Management.

4.1.6 When coupon test stations have been installed on the pipeline for monitoring current density, measurements for both AC & DC current density shall also be collected during the annual CP surveys and recorded in PCS.

1. AC Current Density (I_{AC}) for Coupon Calculation Example:

$$I_{AC} = \frac{8 * V_{AC}}{\rho * \pi * \sqrt{\frac{4 * Coupon\ Surface\ Area}{\pi}}}$$

2. DC Current Density (I_{DC}) for Coupon Calculation Example:

$$I_{DC} = \frac{(\frac{V_{DC}\ across\ Shunt}{Shunt\ Resistance})}{Coupon\ Surface\ Area}$$

4.1.7 The AC current density (I_{AC}) data collected during the annual CP surveys shall be reviewed and based on the results, the following actions shall be taken:

1. **I_{AC} less than 30 A/m^2:** Continue monitoring (loads in transmission lines can vary significantly within 24 hours periods and with seasonal conditions).
2. **I_{AC} between 30 and 100 A/m^2:** Regional Corrosion Control Team Lead or Engineer shall evaluate the ratio of the AC Current Density (I_{AC}) divided by the DC Current Density (I_{DC}) per section 4.1.8 and act accordingly.
3. **I_{AC} greater than 100 A/m^2:** Regional Corrosion Control Team Lead or Engineer shall be responsible for developing and submitting an engineered solution to Management.

4.1.8 If AC current density data collected during the annual CP surveys is between 30 to 100 A/m^2, the ratio of the AC Current Density (I_{AC}) divided by the DC Current Density (I_{DC}) shall be reviewed and based on the results, the following actions shall be taken:

1. **I_{AC}/ I_{DC} less than 5:** Continue monitoring (loads in transmission lines can vary significantly within 24 hours periods and with seasonal conditions).
2. **I_{AC}/ I_{DC} between 5 to 10:** Regional Corrosion Control Team Lead or Engineer shall decide whether or not to develop and submit an engineered solution to Management.
3. **I_{AC}/ I_{DC} greater than 10:** Regional Corrosion Control Team Lead or Engineer shall be responsible for developing and submitting an engineered solution to Management.

4.1.9 The equipment installed for AC surge protection and reduction of induced AC shall be monitored to determine if it is operating correctly and in accordance with criteria listed in section 4.

4.1.10 The adequacy of the pipeline system's surge protection and reduction of induced AC (including station/terminal piping and breakout tanks) shall be tested within the time and frequency listed in Table 2.

4.2 Breakout Tanks

4.2.1 Breakout tanks are generally not susceptible to induced voltage sufficient to cause safety issues or corrosion due to the shape and geometry of the structures. AC safety and corrosion control requirements due to transmission lines are only applicable if the electrical transmission tower footings, ground cables, or counterpoise are in areas where it is reasonable foresee fault currents (49 CFR Part 195.575 (e)).

5.0 LIGHTNING REQUIREMENTS

5.1 Pipelines

5.1.1 Visual inspection of the pipeline shall be conducted to determine susceptibility to lightning strikes and if further action is warranted. While metallic objects do not inherently attract lightning, they are very good conductors and can be affected along further distances than would be normal. A pipeline with grounding at above grade appurtenance is less likely to be detrimentally affected. The structures height, shape, and isolation are factors in determining the likelihood of being struck by lightning.

Specific locations during working hours are extremely hazardous and should be avoided with the onset of thunderstorms (partial listing):

- Hilltops and ridges.
- Areas on top of buildings or tanks.
- Open fields and parking lots.
- Lakes and seashores.
- Near wire fences, overhead wires, and railroad tracks.
- Under isolated trees.
- Near metal or electrically conductive objects such as above grade pipelines.

5.1.2 The design, installation and commissioning of mitigation systems for alternating current and lightning on buried or submerged pipelines shall be in accordance with the referenced NACE SP0177 and NACE SP0169.

Should the results of the visual inspection indicate further testing is warranted, above grade appurtenances such as block valves, metering stations and terminals shall be reviewed for grounding requirements. Pipeline washouts/exposure should be recovered, and measures taken to avoid a reoccurrence.

Grounded aboveground pipeline appurtenances shall be in accordance with IEEE 80.

HVAC Transmission lines crossing or collocated with pipelines shall be analyzed for arcing threats and documented per this standard. If deemed necessary, engineering solutions shall be implemented.

5.1.3 Monitoring and maintenance shall include the continued inspection of the right-of-way for the situations aforementioned and measuring of the grounding resistances in accordance with Table 3.

5.2 Breakout Tanks

5.2.1 Monitoring and maintenance requirements shall be conducted whenever there have been changes made to the structures, after known lightning strikes and any time there are reported incidences. The following items shall be inspected:

- All connections to ensure they are not loose, high resistance and in general good repair (visual and mechanical).
- Corrosion and/or vibrations have not compromised any part of the grounding systems (visual).
- All conductors and ground rods are continuous and intact (visual).
- Electrical isolation and surge protection devices are tested to ensure proper operation and documented in PCS.

6.0 TELLURIC CURRENT REQUIREMENTS

6.1 Pipelines

6.1.1 All pipelines suspected of being affected by telluric currents shall be inspected by identifying any discontinuities in the pipeline (i.e. electrical isolation devices and monitoring). Monitoring shall be in accordance with Table 3. If the monitoring of indicated telluric currents are of large enough magnitude and frequency that mitigation is required, the flowchart in Figure 3 shall be followed.

6.1.2 There are presently no mitigation requirements for Telluric currents, only the methodology for determining if they present measurement errors and procedures to account for them.

6.1.3 There is no equipment installed requiring maintenance, only the methodology required during performing electrical measurements and surveys.

6.1.4 Electrical surveys conducted during telluric currents shall be monitored in accordance with this standard.

6.2 Breakout Tanks

6.2.1 Breakout tanks are generally not susceptible to telluric currents sufficient to cause safety issues or corrosion due to the shape and geometry of the structures.

6.2.2 Monitoring and maintenance requirements shall be conducted whenever there have been changes to the structures, after known lightning strikes and any time there are reported incidences. The following items shall be regularly inspected for the following:

- All connections to ensure they are not loose, high resistance and in general good repair Visual and mechanical).
- Corrosion and/or vibrations have not compromised any part of the grounding systems (visual).
- All conductors and ground rods are continuous and intact (visual).

7.0 SURVEY RECORD KEEPING

Table 2 Survey Record Keeping

Record	Owner	Location
Annual CP Survey Data	Regional Corrosion Control Team Lead or Engineer	PCS Database
CIS Survey Data	Regional Corrosion Control Team Lead or Engineer	PCS Database

Table 3 Inspection Frequencies per 49 CFR Part 192/195

Inspection/Test	Frequency	
	At Least	Not to Exceed
Pipelines: AC structure-to-electrolyte potentials (with annual CP surveys)	1 time per calendar year	15 months
Breakout Tanks: Floating Roof – Internal	Each time the tank is taken out of service for internal inspection	When corrosion rates are not known, 10 years and in any case
Breakout Tanks: All – External	1 time per calendar year	15 months
Pipelines: Decouplers*	1 time per calendar year	15 months
Pipelines: Ground Mat Testing*	Every 5 years	10 years
Pipelines: Zinc ribbon ground conductor*	Every 5 years	10 years
Pipelines: Electrical Isolation devices with surge protection*	1 time per calendar year	15 months

* DC potential readings shall be measured and entered into the "Inspection Remarks" field in PCS.

Note:

MPLX's Regional Corrosion Control Team Lead or Engineer shall be responsible for ensuring compliance with all applicable corrosion control inspection frequencies, that all necessary documentation is completed, and any necessary repairs are made and, as such, shall maintain a thorough knowledge of these requirements.

8.0 FIGURES

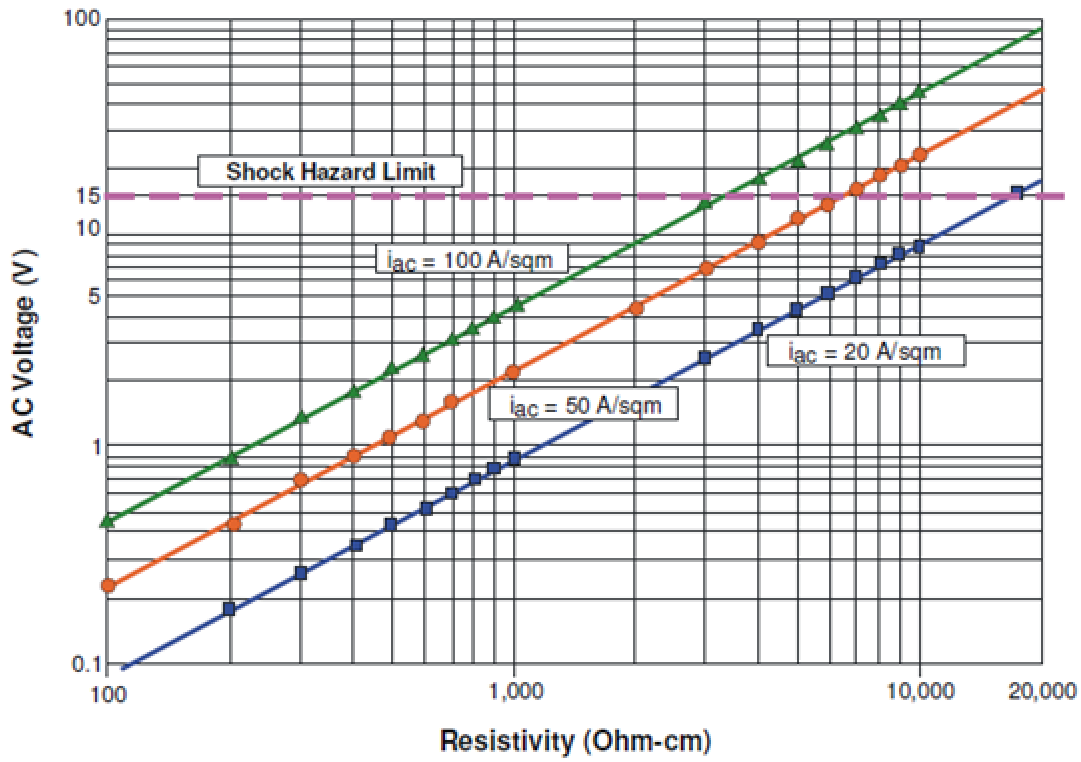


Figure 1 AC Current Densities as a Function of AC Voltage and Soil Resistivity

(Print on 11 X 17 size paper)

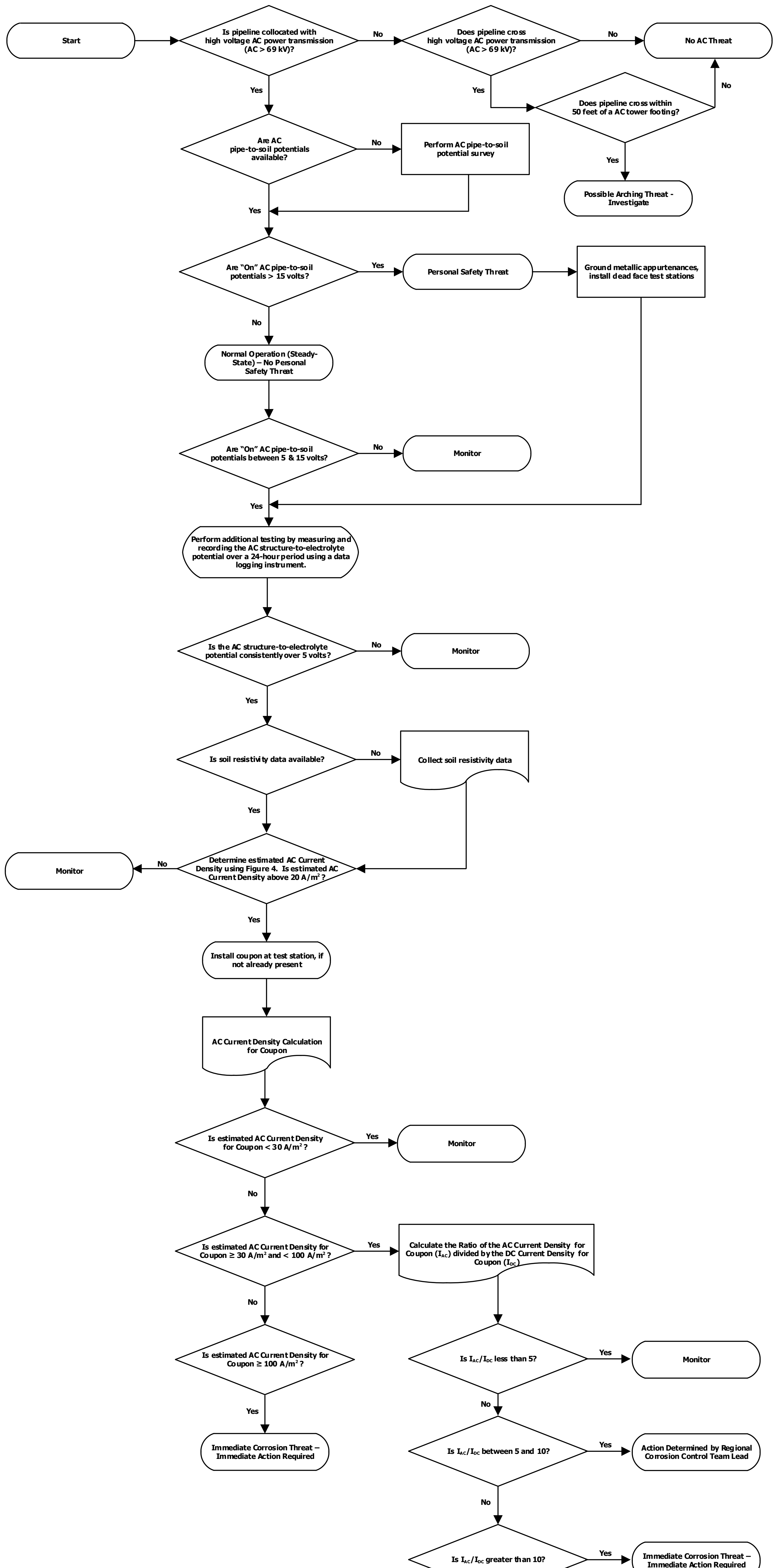


Figure 2 Transmission Line Induced AC Flow Chart

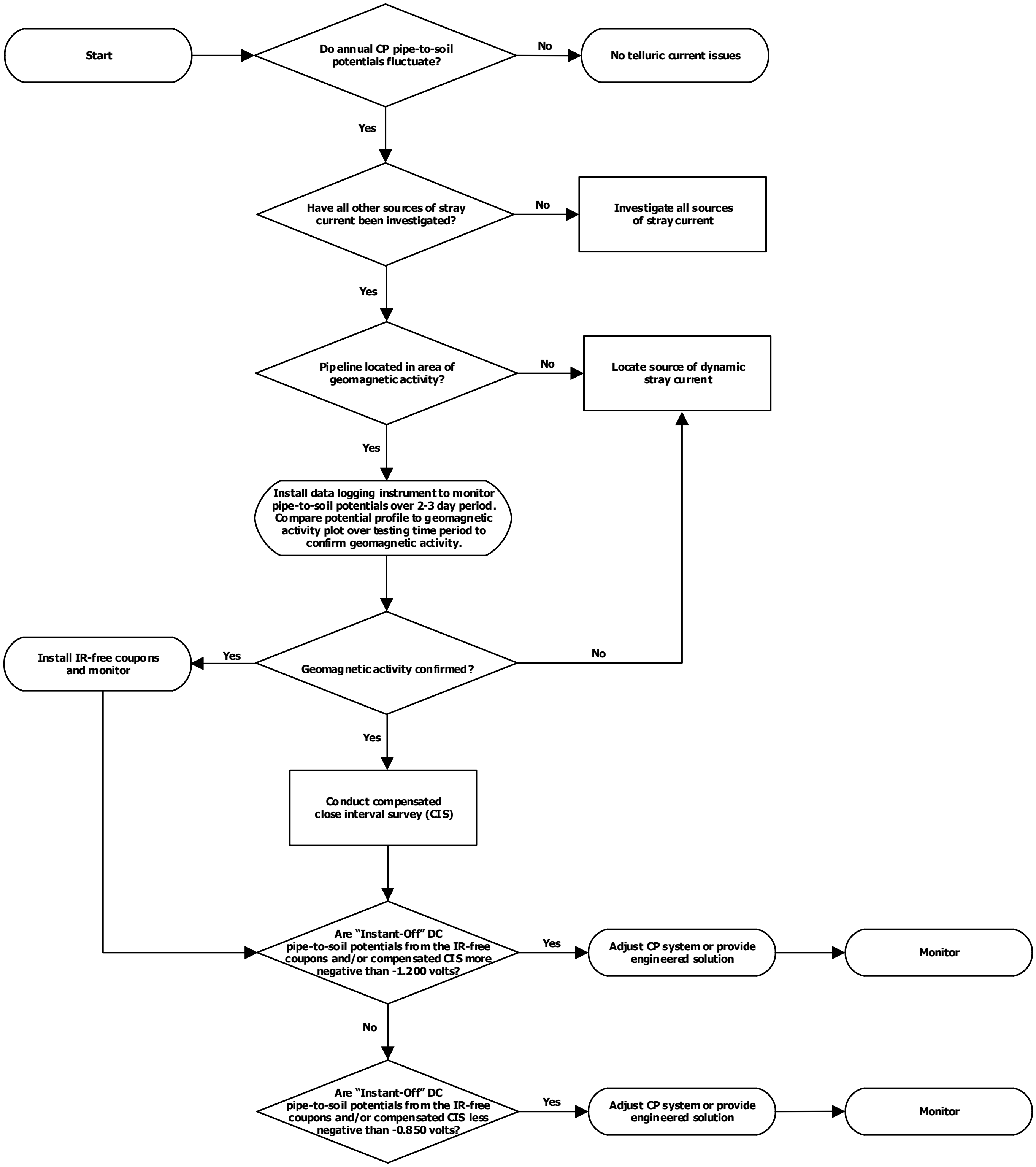


Figure 3 Induced Telluric Current Flow Chart

	Operating Standard	OPS-STD-0026	
MPLX	Corrosion Under Insulation Monitoring, Inspection and Mitigation	Page 1 of 12	
		DATE: 4/1/2021	Rev: 0

Contents

List of Figures

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for the inspection and mitigation of Corrosion Under Insulation (CUI) of pipelines (e.g. valve site) and facilities (e.g. tanks, piping, vessels, etc.) to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021

- The intended service life as well as to streamline all requirements through the standardization of survey procedures, materials, and inspection requirements as they pertain to the mitigation of corrosion under insulation.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets.

1.2.2 This Standard does not include the monitoring, inspection, and mitigation of atmospheric corrosion. The monitoring, inspection, and mitigation of atmospheric corrosion is covered under OPS-STD-0018.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- OPS-STD-0018 Atmospheric Corrosion Monitoring, Inspection and Mitigation Standard
- OPS-STD-0026-FOR-01 Corrosion Under Installation Monitoring, Inspection and Mitigation Form

2.2 Industry Codes and Standards

- ASME B31.3-2006 Process Piping
- ASME B31.4-2006 Pipeline Transportation Systems for Liquids and Slurries
- ASME B31.8-2007 Gas Transmission and Distribution Piping Systems
- API 570-2016 Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems
- API 2611-2011 Terminal Piping Inspection: Inspection of In-Service Terminal Piping Systems
- NACE SP0198-2016 Control of Corrosion Under Thermal Insulation and Fireproofing Materials

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Contractor	Company or business that agrees to furnish materials or perform specified services at a specified price and/or rate to MPLX.
Corrosion	Deterioration of a metal that results from a chemical or electrochemical reaction with its environment.
Holiday	A discontinuity of coating that exposes the metal surface to the environment.

Table 1 Definitions

Term	**Description**
Idled (Inactive)	A pipeline that is not currently used to transport gas or liquids, but continues to be maintained under 49 CFR Part 192 or 49 CFR Part 195.
Inspector/ Person in Charge (PIC)	An MPLX appointed engineer or inspector.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
Onshore	Situated or occurring on land.
Offshore (Marine)	Beyond the line or ordinary low water along that portion of the coast that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.
PCS	Pipeline Compliance System.

4.0 MONITORING INTERVAL

4.1 The pipeline system or portion of the pipeline system that is exposed to CUI shall be inspected for evidence of CUI at the intervals listed below:

4.1.1 Onshore – At least once every three (3) calendar years, but with intervals not exceeding thirty-nine (39) months.

5.0 AREAS OF INTEREST

5.1 The following areas of an insulated pipeline system or portion of an insulated pipeline system shall be inspected for CUI:

5.1.1 Insulated piping systems with damaged, deteriorated or missing insulation.

5.1.2 Insulated piping systems with entrapped water.

5.1.3 Insulated piping systems with bulges in the insulation, staining of the insulation, or missing bands in the jacketing system.

5.1.4 All penetrations or breaches in the insulated piping system, including:

5.1.4.1 Transitions from insulated piping to non-insulated piping.

5.1.4.2 Vents and drains.

5.1.4.3 Pipe hangers and other supports.

5.1.4.4 Valves and fittings (irregular insulation surfaces).

5.1.4.5 Bolt-on pipe shoes.

5.1.4.6 Insulation jacketing seams located on the top of horizontal piping or improperly lapped or sealed insulation jacketing.

5.1.4.7 Caulking of insulated piping systems which has hardened, separated, or is missing.

5.1.4.8 Locations where insulation plugs can be removed to permit piping thickness measurements on insulated piping.

5.2 Special attention shall be made to insulated piping systems which operate in intermittent service, and/or are process dead legs.

6.0 INDIRECT (QUALITATIVE) INSPECTION

Indirect inspection for CUI is broken up into two categories, "Detection of Moisture in Insulation" and "Detection of Metal Loss in Insulated Piping". At least one test method from each category shall be used while performing indirect inspection for CUI.

6.1 Detection of Moisture in Insulation

6.1.1 Infrared Method

6.1.1.1 Infrared scanning of insulated piping can be used as a screening inspection to detect the presence of moisture in insulation. With infrared scanning, a temperature difference between the dry and wet insulation can usually be detected.

6.1.1.2 More moisture can correlate to a higher probability of the presence of CUI.

6.1.1.3 Advantages of the infrared method include:

- Insulation removal is not required.
- Inspection can be performed from a distance.

6.1.1.4 Disadvantages of the infrared method include:

- Insulated pipes not currently in service and that cannot display a large enough temperature difference from the ambient temperature may limit the effectiveness of this inspection method.
- May not provide an accurate indication of insulation system integrity for piping with normal operating temperature above 200°F.

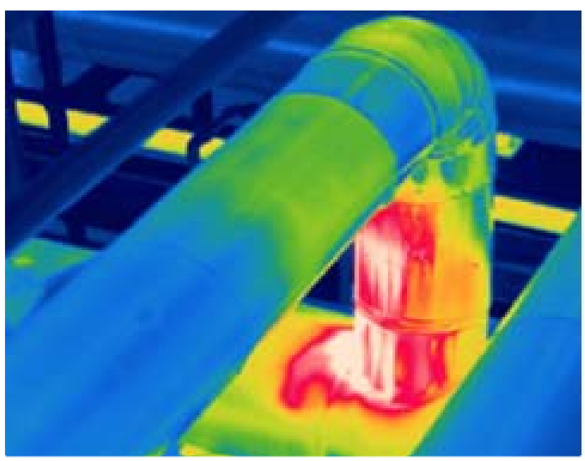


Figure 1 Detection of Moisture in Insulation using Infrared Scanning

6.1.2.1 Similar to infrared scanning, the neutron backscatter system can be used to detect moisture in insulation. With the neutron backscatter system, a radioactive source emits high energy into the insulation. If moisture is present, the hydrogen nuclei attenuate the energy of the neutrons. The instrument's gauge detector is only sensitive to low energy neutrons. The count displayed on the gauge is proportional to the amount of water in the insulation.

6.1.2.2 High counts per time period indicate more moisture and a higher probability of the presence of CUI.

6.1.2.3 Advantages of the neutron backscatter method include:

- Insulation removal is not required.

6.1.2.4 Disadvantages of the neutron backscatter method include:

- Method can sometimes generate false indications.

Figure 2 Detection of Moisture in Insulation using Neutron Backscatter

6.1.3 Visual Inspection

6.1.3.1 Visual inspection can be used for detection of moisture in insulation when removable insulation blankets are present.

6.1.4 Other Methods

6.1.4.1 Alternative indirect inspection methods can be used for detection of moisture in insulation with approval from the Regional Corrosion Control Team Lead.

6.2 Detection of Metal Loss in Insulated Piping

6.2.1 Pulsed Eddy-Current (PEC) Method

6.2.1.1 PEC is an electromagnetic method used to determine the pipe wall thickness. The PEC probe is placed on an insulated pipe or vessel. A magnetic field is created by an electrical current in the transmitting coil of the probe. This field penetrates through the weather sheeting and magnetizes the pipe wall. Next, the electrical current in the transmission coil is switched off, causing a sudden drop in the magnetic field. As a result of electromagnetic induction, eddy currents are generated in the pipe wall. The eddy currents diffuse inwards and decrease in strength. The decrease in eddy currents is monitored by the PEC probe and is used to determine wall thickness.

6.2.1.2 PEC is suitable for detecting general wall loss, but isolated pitting defects cannot be detected.

6.2.1.3 Advantages of the PEC method include:

- Insulation removal is not required.

6.2.1.4 Disadvantages of the PEC method include:

- Method only works with carbon steel and low-alloy steel.
- Pitting defects cannot be detected.

Figure 3 Detection of Metal Loss in Insulated Piping using Pulsed Eddy-Current

6.2.2 Guided Wave Ultrasonic (GUL) Method

6.2.2.1 During GUL testing, a transducer ring is clamped around the pipe and transmits guided waves in both directions along the pipe. Reflected signals from defects and pipe features such as welds are received by the transducer and sent to the main unit for analysis.

6.2.2.2 GUL requires access to the pipe and removal of about 3.3 ft length of insulation at each test location.

6.2.2.3 GUL is suitable for detecting general wall loss, but isolated pitting defects cannot be detected.

6.2.2.4 Advantages of the GUL method include:

- Only a small portion of insulation removal is required.

6.2.2.5 Disadvantages of the GUL method include:

- Successful measurement ranges can differ between 0 to 150 feet depending on pipe (e.g., thickness, coating, etc.) and environmental conditions (e.g., aboveground, buried, etc.).'

6.2.3 Visual Inspection

6.2.3.1 Visual inspection can be used for detection of metal loss in insulated piping when removable insulation blankets are present.

6.2.4 Other Methods

6.2.4.1 Alternative indirect inspection methods can be used for detection of metal loss in insulated piping with approval from the Regional Corrosion Control Team Lead.

7.0 DIRECT (QUANTITATIVE) INSPECTION

The results from the indirect inspection methods (Section 6.0) shall be used to determine if further direct inspection methods are required.

- If moisture in insulation and/or metal loss was observed, further direct inspection methods shall be conducted.
- If moisture in insulation and/or metal loss was not observed, further direct inspection methods are not required.

7.1 Fluoroscopy (C-Arm) Method

7.1.1 Fluoroscopy provides a clear view of the pipes outside diameter through the insulation utilizing a "C" shaped arm device, producing a silhouette of the pipe outside diameter (OD). The X-ray digital fluoroscopy equipment operates at a maximum of 75 KV, a low-level radiation source, but the voltage is adjustable to obtain the clearest image.

7.1.2 The inspection can be viewed during the inspection on a helmet-mounted, visor-type video-display or a TV-type monitor.

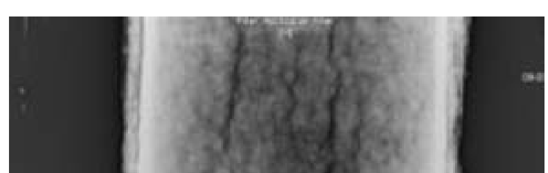
7.1.3 Advantages of the fluoroscopy method include:

- Insulation removal is not required.

7.1.4 Disadvantages of the fluoroscopy method include:

- Limited to a maximum pipe diameter of 24 inches.
- Limited to pipes that have enough clearance from other objects that will allow the C-arm to fit.

7.1.5 If fluoroscopy is not feasible for a given pipe/structure, the "Visual Inspection with Ultrasonic Thickness Measurements Method" shall be used.



7.2 Visual Inspection with Ultrasonic Thickness (UT) Measurements Method

7.2.1 Depending on the severity of the suspected CUI that was determined using the Indirect (Qualitative) Inspection methods (Section 6.0), the inspector shall determine whether using new/pre-existing inspection ports is sufficient or if complete removal of the insulation is required to perform a visual inspection with UT measurements.

7.2.2 If pitting corrosion is present under insulation, a pit gauge shall be used in conjunction with a UT gauge to perform pipe wall thickness measurements.

7.2.3 Advantages of the visual inspection with UT measurements method include:

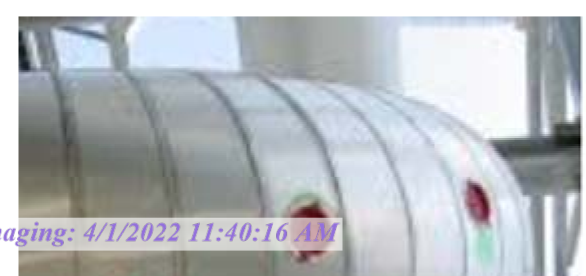
- Visual inspection allows for the most reliable form of inspection.

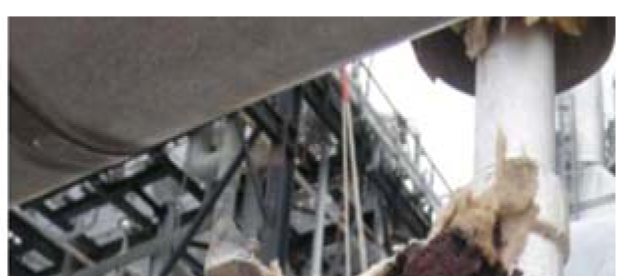
7.2.4 Disadvantages of the visual inspection with UT measurements method include:

- Insulation removal is required.
- Possible exposure to asbestos.
- Time-consuming.
- Expensive, as insulation will need to be replaced.
- Incorrect replacement of inspection ports will create locations for water ingress.

7.3 Other Methods

7.3.1 Alternative direct inspection methods can be used for the analysis of CUI with approval from the Regional Corrosion Control Team Lead or Engineer.





8.0 INSPECTION PROCEDURE

8.1 Individuals performing CUI inspection work shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

8.2 CUI Monitoring, Inspection and Mitigation Procedures shall be recorded using MPLX Form OPS-STD-0026-FOR-01 or by using an Allegro Field PC and recording the fields listed in MPLX Form OPS-STD-0026-FOR-01 (preferred). Following the completion of the survey, the survey data shall be transferred to the PCS database within sixty (60) days of the survey completion date.

8.3 Appendix A contains priority classifications for insulated piping. Priority classifications consist of 3 priority ranges, with a 1 being the most severe and 3 being the least severe. Actions associated with Priorities are defined in the Section 9.0 of this Standard.

8.4 In the field, the Corrosion Control Technician or Qualified Inspector shall assign priorities to the inspected areas of the insulated pipeline system for each area of interest. If no signs are present of CUI, the Inspector shall classify it as Priority 3.

8.5 Photographs shall be taken at each assessed location and stored together with the survey data in the PCS database, which shall be retained per OPS-STD-0017.

8.6 Each exposed area shall be given a unique identifying label, i.e. PIC 01, for reference on future inspections. If piping circuits have been assigned under a prior API 570 or API 2611 inspection, use the piping circuits label as the identifying element.

9.0 CLASSIFICATIONS

9.1 MPLX personnel shall review third-party inspection reports and affirm or modify priority classifications.

9.2 For areas classified as Priority 1 items, an engineering assessment of the metal loss along with remediation shall be conducted per the code associated with the pertinent regulatory agency. Where no regulatory agency has authority, an engineering assessment, along with remediation, shall be performed per ASME B31.3 or ASME B31.4 for liquid service or ASME B31.8 for gas service.

9.3 Areas classified as Priority 2 items shall be re-assessed at the midpoint of the CUI inspection interval. The Corrosion Control Technician/Engineer or Qualified Operator shall re-evaluate the area, and if conditions have changed, re-prioritize the location.

9.3.1 Alternatively, if Priority 2 items receive a coating, they can be re-prioritized to a Priority 3 item.

9.4 Areas classified as Priority 3 items shall be re-assessed at the standard CUI inspection interval and can be re-prioritized at any time.

10.0 REPAIRS

10.1 All repair items shall be assigned a work order and tracked in SAP-PM.

10.2 Repair of Jacketing and Insulation

10.2.1 Damaged jacketing that allows the possibility of moisture ingress shall be repaired/replaced.

10.2.2 Damaged, deteriorated or missing insulation discovered during the inspection shall be repaired/replaced.

10.3 Repair of Pipe Coating

10.3.1 Coating of or coating repairs on insulated piping shall follow the LE-10.001-STD standard.

10.3.2 Coating shall be documented using the appropriate MPLX coating packet forms.

10.4 If metal loss requires repair by mechanical means (e.g. sleeve, weld-overlay, replacement pipe, etc.), an MPLX Pipeline Integrity Engineer shall be consulted to determine the proper type of repair.

11.0 SURVEY RECORD KEEPING

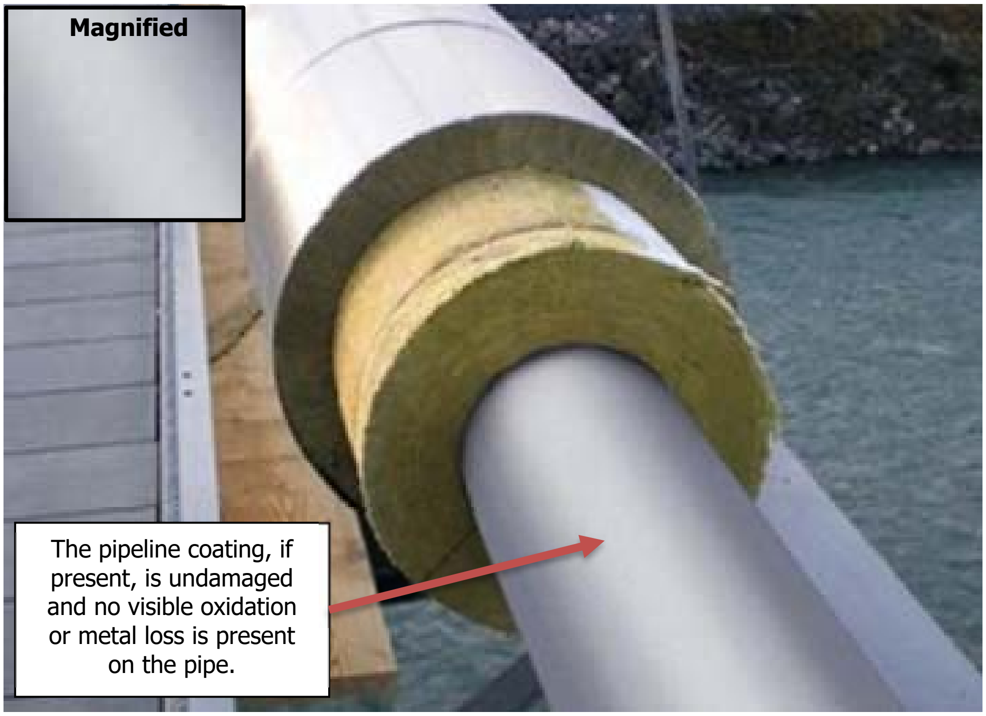
Table 2 Survey Record Keeping

Record	Owner	Location
Corrosion Under Insulation Inspection Survey	Regional Corrosion Control Team Lead or Engineer	PCS Database
Photographs of Piping Circuits	Regional Corrosion Control Team Lead or Engineer	PCS Database

APPENDIX A – INSULATED PIPING PRIORITY CLASSIFICATIONS

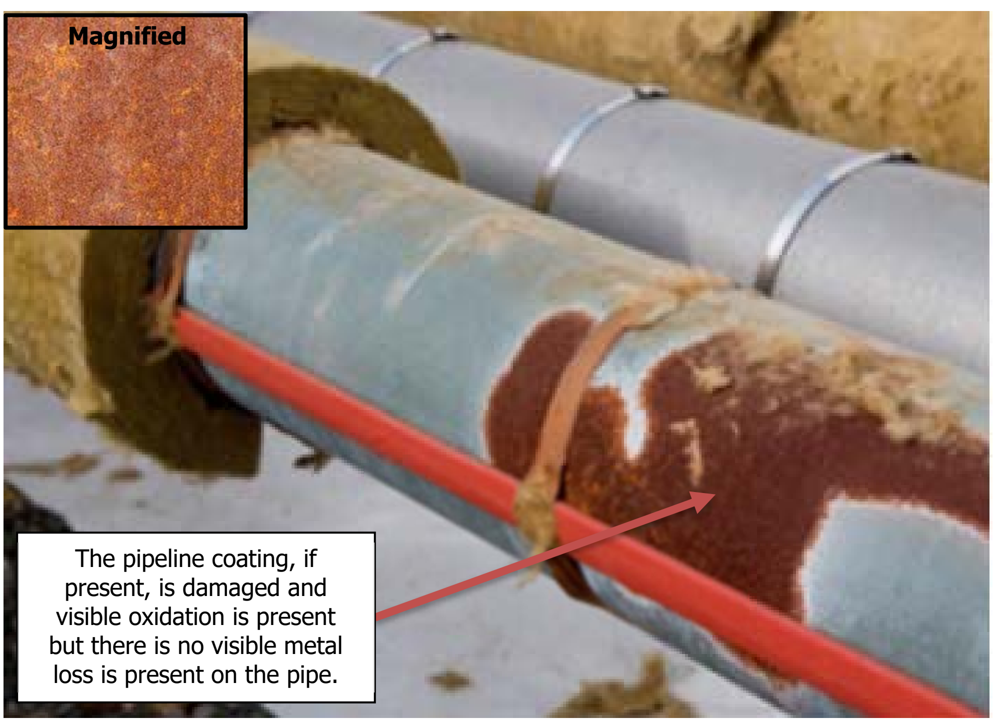
Priority 3

The pipeline coating, if present, is undamaged and no oxidation or metal loss is present.



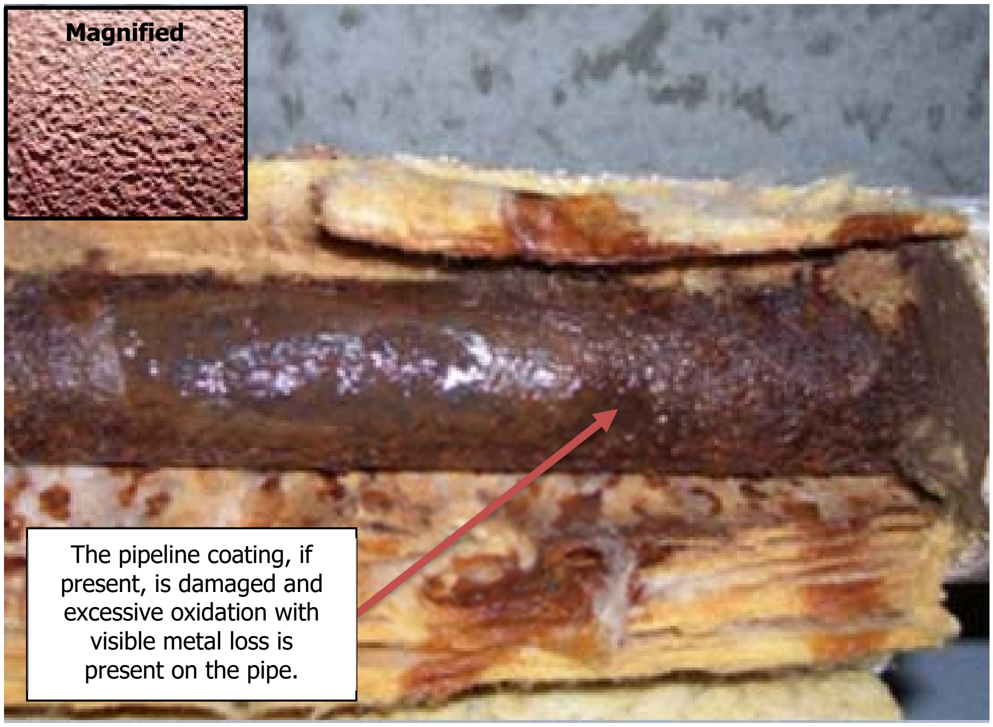
Priority 2

The pipeline coating, if present, is damaged and oxidation is present but there is no metal loss.



Priority 1

The pipeline coating, if present, is damaged and excessive oxidation with metal loss is present.



	Operating Standard	OPS-STD-0027	
MPLX	External Corrosion Direct Assessment	Page 1 of 42	
		DATE: 4/1/2021	Rev: 0

Contents

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021

List of Figures

List of Tables

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for External Corrosion Direct Assessment (ECDA) of pipelines to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life as well as to streamline all requirements through the standardization of survey procedures, materials, and inspection requirements as they pertain to the mitigation of External Corrosion.

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets that fall under the Integrity Management Program (IMP) that are not assessed for integrity by means of inline inspection or hydrotest.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- OPS-STD-0027-FOR-01 ECDA Process Form
- OPS-STD-0027-FOR-02 ECDA data Elements Form
- OPS-STD-0027-FOR-03 ECDA/SCCDA Indirect Inspection Tools Selection Form
- OPS-STD-0027-FOR-04 ECDA Regional Analysis Form
- OPS-STD-0027-FOR-05 ECDA/SCCDA Indication Severity Classification & Dig Site Summary Form
- OPS-STD-0027-FOR-06 ECDA/SCCDA Dig Data Collection Form
- OPS-STD-0027-FOR-07 ECDA Re-Assessment Interval Form
- MPLX Integrity Management Plan

2.2 Industry Codes and Standards

- NACE SP0169-2007 Control of External Corrosion on Underground or Submerged Metallic Piping Systems
- NACE SP0207-2007 Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines
- NACE SP0502-2010 Pipeline External Corrosion Direct Assessment Methodology
- NACE TM0109-2009 Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline
- PHMSA Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs. March 1, 2010.

2.4 Other

- TSCP-006 Cathodic Protection Survey Procedures

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Active	(1) A state of a metal surface that is corroding without significant influence of reaction product; (2) the negative direction of electrode potential.
Alternating Current Voltage Gradient (ACVG) Survey	A method of measuring the change in leakage current in the soil along and around a pipeline to locate coating Holidays and characterize Corrosion Activity.
Anomaly	Any deviation from nominal conditions in the external wall of a pipe, its coating, or the electromagnetic conditions around the pipe.

Term	Description
Cathodic Protection	A technique to reduce the Corrosion rate of a metal surface by making that surface the cathode of an electrochemical cell.
Classification	The process of estimating the likelihood of Corrosion Activity at an Indirect Inspection Indication under typical year-round conditions.
Close-Interval Survey	A method of measuring the potential between the pipe and earth at regular intervals along the pipeline.
Corrosion	The deterioration of a material, usually a metal, that results from a chemical or electrochemical reaction with its environment.
Corrosion Activity	A state in which Corrosion is Active and ongoing at a rate that is sufficient to reduce the pressure-carrying capacity of a pipe during the pipeline design life.
Alternating Current Current Attenuation (ACCA) Survey	A method of measuring the overall condition of the coating on a pipeline based on the application of electromagnetic field propagation theory. Concomitant data collected may include depth, coating resistance and conductance, Anomaly location, and Anomaly type.
Defect	An Anomaly in the pipe wall that reduces the pressure-carrying capacity of the pipe.
Desired Data	A data element that is recommended to be taken into account for the feasibility assessment, designation of ECDA Regions, or analysis of results.
Direct Current Voltage Gradient Survey	A method of measuring the change in electrical voltage gradient in the soil along and around a pipeline to locate coating Holidays and characterize Corrosion Activity.
Direct Examination	Inspections and measurements made on the pipe surface at excavations as part of ECDA.
Disbonded Coating	Any loss of adhesion between the protective coating and a pipe surface as a result of adhesive failure, chemical attack, Mechanical Damage, hydrogen concentrations, etc. Disbonded coating may or may not be associated with a coating Holiday. See also Cathodic Disbondment.
ECDA Region	A section or sections of a Pipeline Segment that have similar physical characteristics, Corrosion histories, expected future Corrosion conditions, and in which the same Indirect Inspection tools are used.
Electrolyte	A chemical substance containing ions that migrate in an electric field. For the purposes of this standard, Electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged metallic piping system, including the moisture and other chemicals contained therein.
External Corrosion Direct Assessment (ECDA)	A four-step process that combines Pre-Assessment, Indirect Inspection, Direct Examination, and Post-Assessment to evaluate the effect of External Corrosion on the integrity of a pipeline.
Fault	Any Anomaly in the coating, including disbonded areas and Holidays.
Geographic Information System (GIS)	A system including data, hardware, software, and personnel, for managing information connected with geographic locations.
High Consequence Area (HCA)	Location along the pipeline that meets the characteristics specified DOT Part 195.450 i.e., location where a pipeline release might have a significant adverse effect on a particularly sensitive area, a commercial waterway, or a high population or other populated area.
Holiday	A discontinuity in a protective coating that exposes unprotected surface to the environment.

Term	Description
Immediate Indication	An Indication that requires Remediation or repair in a relatively short time span.
Indication	Any deviation from the norm as measured by an Indirect Inspection tool.
Indirect Inspection	Equipment and practices used to take measurements at ground surface above or near a pipeline to locate or characterize Corrosion Activity, coating Holidays, or other anomalies.
In-Line Inspection	The inspection of a pipeline from the interior of the pipe using an In-Line Inspection tool. The tools used to conduct ILI are known as pigs or smart pigs.
Maximum Allowable Operating Pressure (MAOP)	The maximum internal pressure permitted during the operation of a pipeline.
Mechanical Damage	Any of a number of types of anomalies in pipe, including dents, gouges, and metal loss, caused by the application of an external force.
Microbiologically Influenced Corrosion (MIC)	Metal Corrosion or deterioration that results from metabolic activity of microorganisms.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
Monitored Indication	An Indication that is less significant than a Scheduled Indication and that does not need to be addressed or require Remediation or repair before the next Scheduled re-assessment of a Pipeline Segment.
Non-Destructive Evaluation (NDE)	An inspection technique that does not damage the item being examined.
Pipeline Segment	A portion of a pipeline that is (to be) assessed using ECDA. A Segment may consist of one or more ECDA Regions.
Structure-to-Electrolyte Voltage (Also Structure-to-Soil Potential or Pipe-to-Soil Potential)	The voltage difference between a metallic structure and reference electrode in contact with a shared Electrolyte.
Polarization	The change from the Corrosion potential as a result of current flow across the electrode/Electrolyte interface.
Prioritization	The process of estimating the need to perform a Direct Examination at each Indirect Inspection Indication based on current Corrosion Activity plus the extent and severity of prior Corrosion. The three levels of priority are *Immediate, Scheduled,* and *Suitable for Monitoring*, in this order.
Required Data	A data element that must be obtained in order to perform ECDA.
Region	See ECDA Region.
Remediation	As used in this standard, Remediation refers to corrective actions taken to mitigate deficiencies in the Corrosion protection system.
Root-Cause Analysis	A family of processes implemented to determine the primary cause of an event. These processes all seek to examine a cause-and-effect relationship through the organization and analysis of data.

Term	Description
Scheduled Indication	An Indication that is less significant than an Immediate Indication, but which is to be addressed before the next Scheduled re-assessment of a Pipeline Segment.
Shielding	(1) Protecting; protective cover against Mechanical Damage; (2) preventing or diverting Cathodic Protection current from its natural path.
Sound Engineering Practice	Reasoning exhibited or based on thorough knowledge and experience, logically valid and having technically correct premises that demonstrate good judgment or sense in the application of science.
Stray Current	Current flowing through paths other than the intended circuit.

4.0 GENERAL REQUIREMENTS

4.1 Procedure

4.1.1 Individuals performing ECDA survey work shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan .

4.1.2 ECDA shall be performed in accordance with NACE SP0502-2010.

4.1.3 ECDA is a structured four-step process for buried onshore piping systems. The intent of the ECDA methodology is to improve pipeline safety by assessing and reducing the impact of External Corrosion on the integrity of the pipeline. A brief description of the four steps in the ECDA process is presented below:

Step 1 Pre-Assessment

Compile historic and current data to determine whether ECDA is feasible, define ECDA Regions, and select the appropriate Indirect Inspection tools. The types of data that are most important during the Pre-Assessment Step of ECDA are typically available in construction records, operating and maintenance histories, alignment sheets, Corrosion survey records, other aboveground inspection records, and inspection reports from prior integrity evaluations or maintenance actions.

Step 2 Indirect Inspection

Covers aboveground inspections to identify and define the severity of coating Faults, other anomalies, and areas where Corrosion Activity may have or may be occurring in the areas under investigation. Two or more complementary Indirect Inspection tools shall be used over the entire Pipeline Segment under investigation to provide improved detection accuracy under the wide variety of conditions that may be encountered along a pipeline right-of-way. The combination of Indirect Inspections may vary based on the characteristics of different Regions that may exist along the Pipeline Segment being assessed.

Step 3 Direct Examination

The data from the Direct Examinations is combined with prior data to identify and assess the impact of External Corrosion on the pipeline.

Step 4 Post-Assessment

Analyses of data collected from the previous three steps to assess the effectiveness of the ECDA and determine re-assessment intervals.

4.1.4 The OPS-STD-0027-FOR-01 form shall be used when completing each step of the ECDA process.

4.2 Qualifications

4.2.1 Qualifications for individuals involved in the ECDA process are summarized in Table 2.

Table 2 Qualifications

Role	Training Requirements & Qualifications
IMP Manager	An individual who possess a Bachelor of Science degree in engineering or technology, plus five years of experience in integrity engineering and EDCA management programs. The individual must have sufficient pipeline experience related to external pipeline Corrosion to provide guidance and oversight to the personnel conducting the ECDA process.
Regional Corrosion Control Team Lead or Engineer	An individual who is qualified as a Regional Corrosion Control Team Lead or Engineer per the qualifications stated in Appendix D of OPS-STD-0017.
Integrity Engineer	An individual who possesses Bachelor of Science degree in engineering or technology, plus three years of pipeline-related engineering or have equivalent pipeline experience in the pipeline industry.
Corrosion Control Technician/Specialist /Engineer	An individual who is qualified through Corrosion Control OQ tasks or the equivalent NACE certifications per Appendix E of OPS-STD-0017.
Nondestructive Examination Specialist (Inspector)	An individual who meets Operator Qualification requirements and is an ANST SNT-TC-1A Level II NDT Examiner for any NDT task to be completed under this plan.

4.3 Equipment

4.3.1 The Integrity Engineer shall be responsible for ensuring all equipment used during the ECDA process is used in accordance with MPLX Cathodic Protection Survey and NDE Procedures. This includes ensuring equipment is calibrated and that individuals using the equipment are properly trained.

4.4 Special Considerations

4.4.1 A key part of the ECDA process is the use of more restrictive criteria during the first application of the process. Each of the four steps of the process has a section dedicated to explicitly stating what additional requirements shall be applied for first time ECDA application. These sections are as follows:

- Pre-Assessment – Section 5.7
- Indirect Inspection - Section 6.6
- Direct Examination - Section 7.9
- Post-Assessment - Section 8.8

5.0 PRE-ASSESSMENT

5.1 Purpose

5.1.1 The purpose of the Pre-Assessment step is to collect sufficient pipeline data to determine if ECDA is feasible for the Pipeline Segment, to select Indirect Inspection tools, and to identify ECDA Regions. The Pre-Assessment step contains the following activities:

- Data collection
- Assessment of ECDA feasibility
- Selection of Indirect Inspection tools
- Identification of ECDA Regions
- Development of an Indirect Inspection Plan

5.2 Data Collection

5.2.1 Historical and current data, including physical information, shall be collected for the Pipeline Segment. Minimum data collection requirements are based on the history and condition of the pipe. The L0-10.025-FOR02 form (cased or uncased piping) shall be used to collect relevant data. The form differentiates between Required, Desired, and Optional Data.

- **Required Data** is information that is critical to completing the ECDA process.
- **Desired Data** is information that is relevant to the ECDA process; however, the information is not critical to the process.
- **Optional Data** is typically informational.

5.2.2 Required Data elements shall be obtained before the completion of the Pre-Assessment step. Desired Data elements should be obtained if the data are available in existing records or it is reasonable to acquire through measurements or examinations.

5.2.3 In the event that Desired Data for a particular category is not available, conservative assumptions shall be used based on experience and information about similar systems. Any assumptions made shall be technically justified and documented by the Integrity Engineer. The Regional Corrosion Control Team Lead or Engineer shall approve the assumptions made.

5.2.2.1 Assumptions shall not to be made for the following data elements:

- Pipe diameter.
- Pipe wall thickness.
- Presence of bare pipe.
- CP system type.
- Coating type.

5.2.4 The Integrity Engineer shall complete the data collection. If Required Data elements are found to be missing or incomplete, a plan shall be implemented to collect the missing data. All data collected shall be recorded in OPS-STD-0027-FOR-02.

5.2.5 There is a unique set of data that must be collected to assess the feasibility of cased piping for ECDA. OPS-STD-0027-FOR-02 shall be used for the data collection of cased piping. This form addresses the different data elements that are required to accurately assess the feasibility of ECDA for cased sections.

5.2.6 Prior assessments of the Pipeline Segment may be used as a resource for Pre-Assessment data; however, they should not be used as a substitute for the data collection process outlined in this procedure.

5.2.7 As an integrity assessment method, ECDA must also integrate data from other sources and assessments. While the purpose of ECDA is to assess the threat of External Corrosion, it is capable of detecting other threats as well. This includes other threats such as Internal Corrosion and Stress Corrosion Cracking, fabrication and construction Defects, threats such as third-party damage, and human error. If another threat is observed during the ECDA process, the Integrity Engineer shall document these findings, so they can be assessed using other appropriate methods. The data from other related integrity assessments are integrated into the ECDA process and included in the Indirect Inspection Plan where relevant information can be used to identify threats to the pipeline.

5.3 ECDA Feasibility

5.3.1 Following the data collection, the Integrity Engineer shall integrate and assess the data to determine if the conditions around the Pipeline Segment are such that two or more complementary Indirect Inspection tools can be used or are such that ECDA can be applied. Specific aspects of the feasibility decision, including technical justification, shall be documented.

5.3.2 If sufficient historical and current data are available on the Pipeline Segment and it can be reasonably concluded that Indirect Inspections will establish Indications of possible Corrosion Activity along a Pipeline Segment, it is reasonable to conclude that ECDA is feasible.

5.3.3 ECDA shall not be considered feasible if there are Required Data elements that were not able to be obtained. In addition, the following environmental conditions may prevent the application of ECDA:

- Locations at which coatings cause electrical Shielding.
- Backfill with significant rock content or rock ledges.
- Certain ground surfaces such as pavement, frozen ground, and reinforced concrete.
- Situations that lead to the inability to acquire aboveground measurements in a reasonable time frame.
- Locations adjacent to buried metallic structures.
- Inaccessible areas.

In the event that one or more of these conditions exist, the Integrity Engineer shall provide technical justification for the application of ECDA in relation to the given condition. This shall be verified and approved by the Regional Corrosion Control Team Lead or Engineer .

5.3.4 There are separate requirements to address the feasibility of the ECDA methodology to conditions specific to cased pipe. Whenever the requirements provided in this standard cannot be effectively implemented on an ECDA Region, the process shall not be considered feasible for that casing/Region.

5.3.5 The following data will be considered during the ECDA feasibility study of cased crossings:

- Data on casing construction.

- Filled-casing data.
- Casing monitoring data.
- Coating type and coating condition.
- History of metallic shorts and or electrolytic contact.
- Data required in OPS-STD-0027-FOR-02 (cased piping).
- Data required in OPS-STD-0027-FOR-03 (cased piping).
- Data required in OPS-STD-0027-FOR-04 (cased piping).

5.4 Identification of ECDA Regions

5.4.1 The entire Pipeline Segment being assessed shall be divided into ECDA Regions. An ECDA Region is a portion of a Pipeline Segment that has similar physical characteristics, Corrosion histories, and expected future Corrosion conditions. The same Indirect Inspections shall be completed over the complete ECDA Region. These Regions may contain non-continuous pipeline sections.

5.4.2 The Integrity Engineer shall establish the ECDA Regions for the Pipeline Segment. The primary decision process for establishing pipeline Regions within a Segment are as follows:

- Availability of prior operating history and a determination that the history is reasonably similar.
- Analysis and determination that the factors that influenced prior Corrosion are known and similar.
- Determination that Indirect Inspections are feasible and that they would yield similar and representative results over the length of the ECDA Region evaluated within the Pipeline Segment.
- A determination that Corrosion Activity, Corrosion growth rates, re-inspection intervals, and the predictive capabilities of the Indirect Inspection tools used are similar.

5.4.3 When identifying ECDA Regions, the Integrity Engineer shall consider the data collected and all conditions that significantly affect (or drive) External Corrosion. For example, a separate ECDA Region may be defined where a pipeline enters or leaves a congested pipeline corridor or right-of-way.

5.4.4 The following provides a description of the relevance of various factors that affect ECDA Region selection.

Age – The year of installation impacts the time over which coating degradation may occur, and the estimation of Defect population and Corrosion rate. The age of the pipe helps indicate the probable steel making process and manufacturing technology used to make the pipe. Older pipe materials typically have lower toughness levels, which reduces critical Defect size and remaining life predictions.

Pipe Related Characteristics – Knowing the specifications and grade to which the pipe was made will provide information about minimum chemical and mechanical properties. Pre-1970 ERW or flash welded pipe seams may be subject to higher Corrosion rates than the base material. Locations with pre-1970 low frequency electric resistance welded (ERW) will increase selective seam Corrosion susceptibility and may require separate ECDA Regions.

Construction Characteristics – Construction practice differences may require separate ECDA Regions. Locations of valves, clamps, supports, taps, mechanical couplings, etc., can be used to help determine changes in CP current that may be considered separately. Locations where CP levels are significantly affected by external sources (e.g., high-voltage electric transmission lines) may be treated as separate ECDA Regions. Outside influences of external power sources may impact the Corrosion mechanism (stray DC and AC Corrosion) that could be present in a pipeline.

Soil and Environment – Soil related and environmental factors are reviewed along the entire length of the pipeline to determine any changes that necessitate separate Regions. There are several factors related to soils that influence the formation and susceptibility to External Corrosion. These include soil type, topography, and drainage. Exposure to bacteria and environments conducive to MIC can prevent an accurate understanding of Corrosion rates, and therefore ECDA is not suited for mitigating MIC.

Pipeline Coating Types – Coating type may influence the time at which Corrosion begins and estimates of Corrosion rate based on measured wall loss. Sections of the pipeline that are coated with polyethylene tape may make it difficult to apply ECDA because of the potential for electrical Shielding of the Cathodic Protection current. For the tape coated sections, ECDA may be applied using soil resistivity coupled with drainage and topography.

Leak and Repair History – Information about pipe replacements or repairs may indicate where problems have occurred in the past. If pipe has recently been replaced, the removed pipe may be available for examination and extrapolations may be made to areas having similar characteristics with respect to soil type, soil resistivity and drainage, etc.

Cathodic Protection Data – External Corrosion develops where Cathodic Protection current cannot penetrate under or through the coating to reach the steel pipe or where there is inadequate distribution of current to bare or ineffectively coated pipe. The length of time without Cathodic Protection is essential in understanding the exposure history of the Pipeline Segment.

5.4.5 The ECDA process relies upon establishing Regions where Indirect Inspections can reliably locate and predict Corrosion Activity. Primary emphasis shall be placed on Cathodic Protection system type, possible interference effects, historical performance, and soil environment.

5.4.6 The ECDA Region selection shall be documented by the Integrity Engineer on OPS-STD-0027-FOR-04 (cased or uncased piping), and submitted to the Regional Corrosion Control Team Lead or Engineer for approval.

5.4.7 ECDA Regions may need to be modified throughout the ECDA process. This could be due to unexpected conditions or tools not performing as expected in the conditions identified. Any change shall be documented and attached to OPS-STD-0027-FOR-01 by the Integrity Engineer. The Integrity Engineer is also responsible for including any changes to ECDA Regions in the Feedback and Continuous Improvement section of the Post-Assessment step.

5.4.8 Due to the unique characteristic of cased piping, cased piping shall be treated as separate ECDA Regions. However, all cased piping may or may not be considered to be one ECDA Region. Differences between individual sections may require multiple ECDA Regions to adequately assess cased piping. If a Pipeline Segment contains different cased sections representing different pipelines, considerations shall be made to the necessity of dividing cased sections in to different ECDA Regions.

5.5 Selection of Indirect Inspection Tools

5.5.1 The Integrity Engineer shall select and document which Indirect Inspection tools are to be used for each ECDA Region along the Pipeline Segment.

5.5.2 At least two complementary (2) Indirect Inspection tools capable of detecting Corrosion Activity and coating conditions reliably under the specific pipeline conditions shall be performed over the entire length of each ECDA Region. Tools selected for each ECDA Region shall complement one another. Specifically, the tools should be selected such that the strengths of one tool compensate for the limitations of another. This program recognizes the six (6) Indirect Inspection tools listed in Table 3.

5.5.2.1 Recommended guidance for performing CIS testing can be located in TSCP-006 Cathodic Protection Survey Procedure 6 "Close Interval Survey (CIS) Testing".

5.5.2.2 Recommended guidance for DCVG testing can be located in TSCP-006 Cathodic Protection Survey Procedure 7 "Direct Current Voltage Gradient (DCVG) Testing".

5.5.2.3 Recommended guidance for ACCA and ACVG testing can be located in TSCP-006 Cathodic Protection Survey Procedure 8 "Alternating Current-Current Attenuation (ACCA) and Alternating Current Voltage Gradient (ACVG) Testing".

5.5.2.4 Recommended guidance for Pearson Survey testing can be located in TSCP-006 Cathodic Protection Survey Procedure 27 "Pearson Survey Testing".

5.5.2.5 Recommended guidance for soil resistivity testing can be located in TSCP-006 Cathodic Protection Survey Procedure 19 "Soil Resistivity Testing".

5.5.3 The use of a tool not listed in Table 3 shall be approved by the Regional Corrosion Control Team Lead or Engineer The justification and verification of the tool shall be documented by the Integrity Engineer.

Table 3 Recognized Indirect Inspection Tools

Indirect Inspection Tool	Measurement Attributes	Typical Uses	Less Suitable For	Complementary Tools
Close Interval Survey (CIS)	Measures structure-to-Electrolyte potentials along the pipeline at 2.5 to 10-foot intervals.	Generally used to assess the performance of CP systems and generally estimate the location of coating Holidays. Can also detect interference, shorted casings, electrical or geological Shielding, contact with other metallic structures as well as Defective electrical isolation joints.	Pipelines that are below paved areas require holes to be drilled to the soil. Is not effective in detecting Disbonded Coatings that are Shielding the pipe from Cathodic Protection current.	DCVG, ACVG, Pearson Survey, ACCA
Current Attenuation Survey (ACCA)	Measures the electro-magnetic field attenuation emanating from the pipe induced with an AC signal. Qualitatively ranks coating quality and highlights areas with the largest Holidays.	Can be used for pipelines under pavement and CP systems that are difficult to isolate.	Not indicative of Structure-to-Electrolyte potential or effectiveness of CP. Is ineffective under HV transmission lines. Is not effective in detecting Disbonded Coatings that are Shielding the pipe from Cathodic Protection current.	CIS
DCVG/ACVG/ Pearson Survey	Measures voltage gradients resulting from current pickup and discharge points at Holidays. Capable of precisely locating Holidays on the pipeline.	Generally used to precisely locate large and small coatings Holidays on buried pipelines.	Pipelines that are below paved areas require holes to be drilled to the soil. Is not effective in detecting Disbonded Coatings that are Shielding the pipe from Cathodic Protection current.	CIS
Soil Resistivity	Measures the resistivity of soil at different layers.	Generally used to characterize the resistance and corrosivity of the soil.	Not indicative of the effectiveness of Cathodic Protection or in determining the effectiveness of coating systems.	CIS, DCVG, Pearson Survey, ACVG, ACCA

5.5.4 The Integrity Engineer shall determine the required number of tools to reliably detect Corrosion Activity for each ECDA Region. The same survey tools do not need to be used over the entire Pipeline Segment.

5.5.5 Table 4 provides additional guidance for selecting Indirect Inspection tools and specifically addresses conditions under which some Indirect Inspections tools may not be practical or reliable.

5.5.6 OPS-STD-0027-FOR-03 (cased or uncased piping) is to be used to document the tools selected. The Integrity Engineer shall complete this form and document supporting justification. This form and supporting technical justification shall be verified and approved by the Regional Corrosion Control Team Lead or Engineer .

Table 4 Indirect Inspection Tool Selection

Conditions	Close Interval Survey (CIS)	Voltage Gradient Survey (DCVG and ACVG)	Pearson Survey	Current Attenuation Survey (ACCA)
Coating Holidays	2	1,2	2	1,2
Anodic zones on bare pipe	2	3	3	3
Near river or water crossings	2	2	2	2
Under frozen ground	3	3	3	1,2
Stray currents	2	1,2	2	1,2
Shielded Corrosion Activity	3	3	3	3
Adjacent metallic structures	2	1,2	3	1,2
Near parallel pipelines	2	1,2	3	1,2
Under high-voltage alternating current overhead electric transmission lines	2	1,2	2	2
Under paved roads	3	3	3	1,2
Crossing other pipelines	2	1,2	2	1,2
Cased piping	3	3	3	3
At very deep depth of cover	3	3	3	3
Wetlands	2	1,2	2	1,2
Rock terrain/rock ledges rock backfill	3	3	3	2

Key:

1 - Applicable: Small coating Holidays (isolated and typically less than 600 mm^2 (1 in^2) and conditions that do not cause fluctuations in CP potentials under normal operating conditions).

2 - Applicable: Large coating Holidays (isolated and continuous) or conditions that cause fluctuations in CP potentials under normal operating conditions.

3 - Applicable when it can be demonstrated, through Sound Engineering Practice and thorough analysis of the inspection location, that chosen methodology produces accurate comprehensive results that result in a valid integrity assessment of the Pipeline Segment.

5.5.7 Cased piping creates limitations for Indirect Inspection tools and the ability of those tools to detect Corrosion Activity. As such, other considerations are made for Indirect Inspection tools that are to be used for cased piping.

Additional considerations should reflect the level of performance of each tool, and the nature of the data or information that can reasonably be expected from the tools. The main limitation of most Indirect Inspection tools is that they can only reliably identify if there is a pipe-to-casing electrical continuity of some kind, but not differentiate between continuities.

5.6 Developing an Indirect Inspection Plan

5.6.1 An Indirect Inspection Plan shall be developed prior to commencing the Indirect Inspections. The plan addresses project logistics, survey procedures and specifications, safety procedures, personnel requirements, and data analysis requirements. The plan must include, but is not limited to, the following:

- Pipeline Segment maps with boundaries and pertinent information clearly identified and labeled by location (e.g. bonds, casings, roads, etc.).
- Clearly defined ECDA Region(s) along the entire Pipeline Segment to be assessed.
- Identified Indirect Inspection surveys to be performed within each ECDA Region and the sequence in which the surveys must be conducted.
- Flagging and stationing methodology to be used during the surveys
- The training, experience or OQ requirements for the individuals conducting the Indirect Inspection surveys.
- The procedures for performing each survey including, but not limited to, the limitations and sensitivities of the technique and the spacing required between readings.
- Requirements on overlapping surveys, if applicable.
- Weather or seasonal considerations (frozen ground).

5.6.2 The plan shall be documented by the Integrity Engineer, and submitted to the Regional Corrosion Control Team Lead or Engineer. The Regional Corrosion Control Team Lead or Engineer shall be responsible for managing the plan.

5.7 Additional Requirements for First Time Application

5.7.1 When ECDA is applied for the first time on a Pipeline Segment, more stringent requirements apply. The Regional Corrosion Control Team Lead or Engineer shall be responsible for ensuring that more restrictive criteria are used when ECDA is being applied for the first time. The Integrity Engineer shall document the more restrictive criteria implemented in OPS-STD-0027-FOR-01.

5.7.2 At least one of the following tasks shall be completed when applying ECDA on a Pipeline Segment for the first time:

- Collecting soil resistivity measurements during the Indirect Inspection step.
- Segregating HCA included Segments into additional ECDA Regions.
- Potholing to confirm depth of covers, pipe coatings, and soil conditions, etc.
- Locating and pre-marking the entire Pipeline at 5-foot intervals prior to conducting the Indirect Inspections
- A site visit by the Integrity Engineer and/or Regional Corrosion Control Team Lead or Engineer to the Pipeline Segment.

6.0 INDIRECT INSPECTION

6.1 Purpose

6.1.1 The purpose of the Indirect Inspection step is cover aboveground inspections (Table 3) to identify and define the severity of coating Faults, other anomalies, and areas where Corrosion Activity may have or may be occurring in the areas under investigation.

6.2 Conducting Indirect Inspections

6.2.1 After the Indirect Inspection Plan has been approved by the Regional Corrosion Control Team Lead or Engineer , the aboveground surveys are conducted in accordance with the MPLX L&S – Southwest Gathering Corrosion Control Program, MPLX Logistics Cathodic Protection Survey Procedures, and this standard. The surveys shall be completed by a survey crew and each survey crew shall include at least one Corrosion Technician/Specialist/Engineer.

6.2.2 The Indirect Inspections shall be conducted and completed as close together in time as practical.

6.2.3 The boundaries of the ECDA Pipeline Segment shall be identified and physically marked prior to performing the Indirect Inspection surveys.

6.2.4 During the Indirect Inspections, accurate stationing for readings shall be obtained. Accuracy shall be verified by the Integrity Engineer by comparing measured stationing to the alignment sheet for the Pipeline Segment. The difference between the measured stationing and the stationing of locations on the alignment sheet shall be less than 2%. The Integrity Engineer shall be responsible for resolving any discrepancies. The Pipeline Segment shall be located with reference to clearly described aboveground locations. GPS measurements shall be collected at every reading and at every pipeline feature or appurtenance along the right-of-way. This includes recording the position of the following:

- Each pipeline marker.
- Cathodic protection test stations.
- The edges and center of:
  - Road crossings
  - Waterways.
  - Ditches.
- Fences.
- Overhead power lines.
- Foreign line and utility crossings.
- Any sections of exposed pipe.
- Any locations with evidence of soil erosion along the right-of-way.

6.2.5 The Integrity Engineer shall witness a portion, or all, of the Indirect Inspections to verify that the Indirect Inspection personnel are following the ECDA Indirect Inspection Plan. Any such field audits and their findings shall be documented by the Integrity Engineer and given to the Indirect Inspection personnel. The audit findings shall also be reviewed by the Regional Corrosion Control Team Lead or Engineer .

6.3 Data Alignment and Comparison

6.3.1 The Integrity Engineer shall overlay the data sets from the Indirect Inspections. The results of data alignment shall be documented as part of the final report. The data are aligned such that individual Indications on coated lines can be identified, or such that possible anodic areas on bare lines can be identified. The results of the surveys shall be compared to the Pre-Assessment data to confirm the feasibility of ECDA and confirm ECDA Regions were appropriately defined. If discrepancies exist regarding the ability of tools to accurately inspect the Pipeline Segment, these discrepancies shall be resolved by the Integrity Engineer prior to proceeding to the next activity in the Indirect Inspection step. Any discrepancy, and associated resolution, shall be documented and attached to the OPS-STD-0027-FOR-01 form.

6.3.2 The impact of spatial errors from various techniques shall be considered when aligning data. Any suspected spatial errors shall be investigated prior to the Indication Classification and Prioritization step.

6.4 Identifications of Indications

6.4.1 The Integrity Engineer shall be responsible for identifying ECDA Indications. Analysis software may also be used, if approved by the Regional Corrosion Control Team Lead or Engineer, based on comparisons between surveys. The criteria for determining ECDA Indications may be determined on a per project basis as results may vary based on local conditions and unique project factors. At a minimum, criteria for identifying ECDA Indications must consider the following:

- The known sensitivities of the survey equipment.
- The procedures used during the survey.
- The approach used for decreasing the physical spacing between measurements.

6.4.2 The criteria for identifying ECDA Indications shall be based on Sound Engineering Practice and conform to generally accepted industry practices. Typically, potential ECDA Indications are changes in measured values that exceed normal variations (e.g. "noise") and cannot be explained by changes in conditions along the ECDA Region. For example, a signal strength change that is greater than five times the instrument resolution might be considered an Indication. When a clear determination cannot be made regarding Indications, assumptions shall be conservative such that a potential Indication is considered to be an Indication unless additional investigation proves otherwise. Additionally, any changes to the criteria during the selection process are to be documented with justification.

6.4.3 The final criteria for selecting ECDA Indications shall be documented by the Integrity Engineer. The criteria shall then be verified and approved by the Regional Corrosion Control Team Lead or Engineer . These criteria shall to be attached to OPS-STD-0027-FOR-01. Selection criteria need not be the same for each ECDA Region; however, if criteria are different, the different criteria shall be documented with justification for the differences.

6.4.4 ECDA Indications shall be selected by evaluating superimposed data from different ECDA tools, local environmental conditions, and physical pipeline features. When potential Indications from multiple tools (and other related information) coincide, the location will be considered an ECDA Indication.

Indications will be chosen using engineering analysis and judgment of signal relevance (e.g. CIS dips, alignment with DCVG, etc.).

6.4.5 Locations where the Indirect Inspection survey results are not consistent shall be identified. Locations where one survey identifies an Indication, but others do not, shall be evaluated to determine if the discrepancies can be explained by inherent tool capabilities or specific/localized pipeline features or conditions. If discrepancies cannot be explained, additional surveys or preliminary Direct Examinations shall be considered as follows:

- Use additional complementary survey tools.
- Use an approach to decrease the physical spacing of Indirect Inspection tool readings is followed when the presence of an Indication is suspected.
- Perform preliminary Direct Examinations to resolve discrepancies, provided the examinations identify a localized and isolated cause of the discrepancy.
- If the above do not resolve the discrepancies, ECDA feasibility may be reassessed. In addition, additional Direct Examinations may be considered, or the location may be prioritized as for Immediate action required on Direct Examination step.

6.4.6 While ECDA is suited best for detecting External Corrosion, it is capable of detecting other threats to the pipeline. Data that have been integrated from other sources shall be considered when identifying Indications. Other sources include operational or incident data, encroachment records, "one call" records, or data showing close proximity of foreign structures. If an Indication from the ECDA process detects an Anomaly where another integrity threat may exist, for example a location where third-party damage may have occurred, these locations shall also be considered for Direct Examination.

6.5 Classification of Indication Severity

6.5.1 The Integrity Engineer shall define and apply severity Classification criteria for identified ECDA Indications based on the likelihood of Corrosion Activity. The Integrity Engineer is responsible for ensuring that the criteria are documented. The final criteria shall be attached to OPS-STD-0027-FOR-01. The final criteria shall also be approved by the Regional Corrosion Control Team Lead or Engineer . The criteria must take into account the specific conditions along the pipeline during the survey. The following Classifications are used at a minimum:

- **Severe -** Indications that are considered as having the highest likelihood of Corrosion Activity.
- **Moderate -** Indications that are considered as having possible Corrosion Activity.
- **Minor -** Indications that are considered Inactive or have the lowest likelihood of Corrosion Activity.

6.5.2 More detailed criteria may be used if necessary. Table 5 provides general guidelines of Indication Classification. A weighted algorithm shall be used to determine the Indication Classification. The algorithm applies a numerical value for each survey result and then factors are applied to these numerical values to provide more significance to the results deemed most likely to be associated with Corrosion Activity.

Table 5 General Guidelines for Indication Classifications

Tool/Environment	Minor	Moderate	Severe
CIS, aerated, moist soil	Small dips with on and off potentials above CP criteria	Medium dips or off potentials below CP criteria	Large dips or on and off potentials below CP criteria
DCVG survey, similar conditions	Low voltage drop; cathodic conditions at Indication when CP is on and off	Medium voltage drop and/or neutral conditions at Indication when CP is off	High voltage drop and/or anodic conditions when CP is on or off
ACVG or Pearson survey, similar conditions	Low voltage drop	Medium voltage drop	High voltage drop
Soil Resistivity	Mildly Corrosive Soil	Corrosive Soil	Very Corrosive Soil
ACCA survey	Small increase in attenuation per unit length	Moderate increase in attenuation per unit length	Large increase in attenuation per unit length

6.5.3 Table 6 provides an example methodology for determining a numerical value score for each survey result. The determination criteria provided in Table 6 may be used as a default or altered by the Integrity Engineer, if necessary, to meet the needs of each individual project. Any alteration to the numerical weighting shall be approved by the Regional Corrosion Control Team Lead or Engineer . This process also applies for cased piping; however, a different algorithm should be utilized based on a numerical score assigned to each survey result used to analyze the cased piping. The numerical weight applied to each variable is based on the confidence of the data collected and the increased likelihood of Corrosion based on the survey finding. A higher calculated weighting factor (W), as shown in Equation 1, is a result of the severity of the individual Indications based on the accuracy of the indirect tool. As such, Indications that pose a greater risk coupled with a less accurate survey technique result in a more conservative and thus higher priority ranking for Direct Examination Classifications.

Table 6 Criteria for Classifying Indications with Numerical Rankings

Variable	Tool/Environment	Minor	Moderate	Severe
		0.5 Score	**1.5 Score**	**2.5 Score**
A1	CIS, aerated, moist soil - CP Meets Protection Criteria	Off doesn't meet -0.85 V criterion but meets 100 mV criterion	On meets -0.85 V criterion, Off doesn't meet -0.85 V criterion or100 mV criterion	On & Off doesn't meet -0.85 V criterion or 100 mV criterion, or reverse potential shift
B1	DCVG survey, similar conditions	<15% IR	16 to 35 % IR	> 35 % IR
B2	CIS, aerated, moist soil – Potential Dips	<50 mV dip	50 – 100 mV dip or < Criteria	>100 mV dip or < Criteria
B3	Wenner 4-pin	> 10,000 Ohm-cm	1000-10000 Ohm-cm	< 1000 Ohm-cm
B4	ACVG or Pearson survey, similar conditions	Low voltage drop	Medium voltage drop	High voltage drop
B5	ACCA survey	Low signal loss	Medium signal loss	Large signal loss
B6	Carrier Structure-to-Electrolyte and Casing-to-Electrolyte Potential Test	Potential difference greater than 100 mV	Potential difference between 100 mV and 5 mV	Potential difference smaller than 5 mV

6.5.4 An example weighting algorithm for combining indirect survey results and determining the severity Classification is as follows:

$$W = 3A_1 + 2B_{(1 \text{ or } 4 \text{ or } 5)} + B_{(2 \text{ or } 3 \text{ or } 6)} \quad (1)$$

Where:

A1 = The numerical score of the CIS survey results (CP Meets Protection Criteria) where anomalies are identified.

B1 = The numerical score of the DCVG survey results where anomalies are identified.

B4 = The numerical score of the ACVG or Pearson survey results where anomalies are identified.

B5 = The numerical score of the Current Attenuation Survey results where anomalies are identified.

B2 = The numerical score of the CIS survey results (Potential Dips) where anomalies are identified.

B3 = The numerical score of the Soil Resistivity results where potentially corrosive environments are identified.

B6 = The numerical score of the Carrier Structure-to-Electrolyte and Casing-to-Electrolyte Potential Test.

6.5.5 Final Classification of the ECDA Indications based on the weighted algorithm could then be determined based on the ranges provided in Table 7.

Table 7 Indications Severity Classification Range

Indication Severity Classification	Weighting Algorithm (W) Range
Severe	$12 \leq W \leq 15$
Moderate	$6 \leq W < 12$
Minor	$0.5 \leq W < 6$

6.5.6 The Classification ranges presented in Table 7 may be used as a default; however, the Integrity Engineer may consider the use of a different weighting algorithm based on the specific pipeline conditions. If altered, the Indication Severity Classification algorithm shall be documented and approved by the Regional Corrosion Control Team Lead or Engineer .

6.5.7 The Indication severity for identified Indications shall be documented in OPS-STD-0027-FOR-05 by the Integrity Engineer. This information shall be approved by the Regional Corrosion Control Team Lead or Engineer .

6.6 Additional Requirements for First Time Application

6.6.1 When ECDA is applied for the first time, any location where discrepancies cannot be resolved shall be categorized as Severe. In addition, the Classification criteria shall be as stringent as possible.

6.6.2 One or more of the following tasks shall be completed when applying ECDA on a Pipeline Segment for the first time:

- Repeat a portion of each Indirect Inspection survey in the opposite direction and compare results.
- Repeat a portion of the Indirect Inspection at a later date and compare for consistencies.
- Decrease thresholds for each severity level in Table 7 for each tool, such that the severity of Indications increases.
- Provide additional training for Indirect Inspection Personnel or use individuals with a higher level of qualification than the minimum levels specified in this procedure.
- Provide additional oversight during inspections by having the Integrity Engineer on-sight.
- Utilize more than two Indirect Inspection tools.
- Re-survey before excavations.
- For indirect survey tool conflicts, even if resolved, redo Indirect Inspections for all tools.
- Any other action that can be technically justified to provide added accuracy and confidence to the indirect step beyond what is required herein. This is documented as an additional Indirect Inspection activity for first time application.

7.0 DIRECT EXAMINATION

7.1 Purpose

7.1.1 The purpose of the Direct Examination step is to determine which Indications from the Indirect Inspections pose the highest risk and to collect data to assess Corrosion Activity. Sites selected for Direct Examination require exposure of the pipeline and coating surface so that a detailed inspection and examination can be performed. The Direct Examination step includes the following activities:

- Indication Prioritization.
- Determining the required number of excavation for Direct Examination.
- Scheduling excavations.
- Excavation and data collection.
- Corrosion damage and Corrosion data collection.
- Remaining strength evaluation.
- In-process evaluation.

7.2 Prioritization

7.2.1 Each identified Indication shall be categorized as Immediate, Scheduled, or Suitable for Monitoring as defined in NACE Standard Practice SP0502-2010. Prioritization is based on two factors: the likelihood of current or future Corrosion Activity plus the extent and severity of prior Corrosion damage.

- **Immediate –** Immediate Indications are those Indications which are considered as likely to have ongoing Corrosion Activity and which, when coupled with prior Corrosion, pose an Immediate threat to the pipeline. The following may be considered when prioritizing Indications as Immediate:
  - o Multiple Severe Indications in close proximity and isolated Indications that are classified as Severe by more than one Indirect Inspection technique at roughly the same location shall be considered Immediate Indications.
  - o Indications for which the likelihood of ongoing Corrosion Activity cannot be determined and Severe or Moderate Indications where significant prior Corrosion is suspected at or near the Indication shall also be considered Immediate Indications.
- **Scheduled –** Scheduled Indications are those Indications which are considered as potentially having ongoing Corrosion Activity but which, when coupled with prior Corrosion, do not pose an Immediate threat to the pipeline under normal operating conditions. The following shall be considered when prioritizing Indications as Scheduled:
  - o All Indications classified as Severe that are not in close proximity to each other and have not been prioritized as Immediate Indications shall be considered Scheduled Indications.
  - o Indications classified as Moderate where significant or prior Corrosion is likely at or near the Indications shall also classified as Scheduled Indications.
- **Suitable for Monitoring –** Indications that are Suitable for Monitoring are those which are considered Minor or as having the lowest likelihood of ongoing or prior Corrosion Activity.

7.2.2 The year-round conditions around a pipeline shall also be considered in setting the excavation priority criteria. This includes physical characteristics of each

ECDA Region that affect the performance and effectiveness of the Cathodic Protection system.

7.2.3 The guidelines stated in Table 8 shall be used to prioritize the actions regarding to the schedule of Direct Examination of Indications from Indirect Inspections. All the results shall be documented in OPS-STD-0027-FOR-05 with station number, Classification, and Prioritization. The Prioritization of Indication shall be completed by the Integrity Engineer and verified and approved by the Regional Corrosion Control Team Lead or Engineer .

Table 8 Prioritization Criteria for Indirect Inspection Indications

Immediate Action Required	Scheduled Action Required	Suitable for Monitoring
• Severe Indication in close proximity regardless of prior Corrosion • Individual Severe Indication or groups of Moderate Indications in Regions of Moderate prior Corrosion • Moderate Indications in Regions of Severe prior Corrosion • Any Indication of a metallic short between the casing and carrier pipe.	• All remaining Severe Indications • All remaining Moderate Indications in Regions of Moderate prior Corrosion • Groups of Minor Indications in Regions of Severe prior Corrosion • Any Indication of electrolytic contact between the casing and carrier pipe where the pipe potential is not meeting protection criteria.	• Any Indication of electrolytic contact between the casing and carrier pipe where the pipe potential is meeting protection criteria. • All remaining Indications

7.2.4 A similar Prioritization approach may be used for cased piping; however, due to the difficulty in determining the condition of cased piping, an intermediate step should be applied. Guided Wave Ultrasonic Testing (GWUT) is an effective method to supplement the selected Indirect Inspection tools to better prioritize Indications. As such, GWUT may be used to determine which Indications will require Direct Examination. After Indication Classification has been performed, the following action shall be taken:

- For each cased pipe ECDA Region, all Immediate Indications shall be screened using GWUT.
- For each cased pipe ECDA Region, where no Immediate Indications are identified, at least one Scheduled Indication is screened using GWUT or a better suitable nondestructive examination technique, at the cased crossing with the highest likelihood of Corrosion Activity.
- For each cased pipe ECDA Region, where neither Immediate nor Scheduled Indications are identified, at least one Suitable for Monitoring Indication shall be screened using GWUT.

7.2.5 The data from the GWUT shall be compared to the data from Indirect Inspection tools to prioritize which locations will require Direct Examinations. The following requirements shall be used to prioritize Indications on cased piping:

- **Immediate Priority Indications** include:
    - o Any Indication identified as a metallic short.

- Guided Wave UT Indication greater than 50% wall loss.
- If applicable, any Indication of a change in casing integrity including change in wax fill height or quality.

- **Scheduled Indications** include:
  - Any Indication of electrolytic contact between the casing and carrier pipe where the pipe potential is not meeting protection criteria.
- **Suitable for Monitoring Indications** include:
  - Any Indication of electrolytic contact between the casing and carrier pipe where the pipe potential is meeting protection criteria.
  - Any Indication where there is no evidence of a short and where Corrosion Activity is unlikely.

7.2.6 Indications in close proximity to a casing shall result in the casing being excavated unless additional testing can provide technical justification that the Indication is not associated with the casing. Indications at casings that have been selected for Direct Examination shall be examined over the entire casing.

7.3 Determining the Required Number of Excavations for Direct Examination

7.3.1 The Integrity Engineer shall be responsible for selecting sites for Direct Examination. The number of Direct Examination sites shall meet the requirements described herein at a minimum; however additional sites may need to, and at times, should be considered. If previous excavations have been performed due to any reason for Direct Examination, the results of the Direct Examinations of those excavations should be taken into account to define the final total number of excavations required.

7.3.2 The minimum required number of Direct Examination sites per ECDA Region shall be based on the following guidelines:

- All Indications prioritized as Immediate shall be examined.
- For each Region that contains Scheduled Indications:
  - At least one (1) Direct Examination shall be completed at the Indication that poses the greatest risk, as determined in the Classification of Indication severity, for Direct Examination.
  - If ECDA is being applied for the first time, one (1) additional Direct Examination shall be performed at the Indication that poses the next greatest risk.
    - If there is only one (1) Scheduled Indication in a Region, then the Direct Examination occurs at a Suitable for Monitoring Indication.
  - If the results of a Scheduled Indication show Corrosion that is deeper than 20% of the nominal wall thickness and that is deeper or larger than an Immediate Indication, at least one (1) additional Direct Examination shall be required at the next highest ranking and prioritized Indication.

  - ▪ If the above condition is met and ECDA is being applied for the first time, one (1) additional Direct Examination shall be performed at the second highest ranking prioritized Indication.

- If no Immediate or Scheduled Indications are identified in an ECDA Region, at least one (1) Direct Examination shall be performed.
  - o If ECDA is being applied for the first time, one (1) additional Direct Examination shall be performed at the second highest ranking prioritized Indication.
  - o If multiple ECDA Regions contain only Suitable for Monitoring Indications, one (1) Direct Examination shall be performed in the Region identified as most likely for External Corrosion Activity based on the Pre-Assessment.
    - ▪ If the above condition is met and ECDA is being applied for the first time, one (1) additional Direct Examination shall be performed at the second highest ranking prioritized Indication.
- If no Indications are identified in an ECDA Region, at least one (1) Direct Examination shall be performed.
  - o If ECDA is being applied for the first time one (1) additional dig is completed.

7.3.3 The Direct Examination sites shall be documented in OPS-STD-0027-FOR-06 by the Integrity Engineer. The summary shall be submitted to the Regional Corrosion Control Team Lead or Engineer with the transaction date noted. The summary shall be verified and approved by the Regional Corrosion Control Team Lead or Engineer .

7.4 Scheduling

7.4.1 The Regional Corrosion Control Team Lead or Engineer shall responsible for establishing a schedule for conducting Direct Examinations at all locations selected by the Integrity Engineer, based on the excavation priorities and the number of excavations to be conducted. The excavation schedule shall be developed within 30 days of completion of the Indication Prioritization. In setting a schedule, the Regional Corrosion Control Team Lead or Engineer shall consider issues such as the following:

- Permitting.
- Right-of-way access.
- Time needed to ensure that adequate inspection equipment is available.
- Time needed to ensure that appropriate crews are available.
- The schedule may recognize that, for example, permitting in a public area has been applied for but not approved by the correspondent authority.

7.4.2 Within 30 days of the completion of the Indication Prioritization, the Regional Corrosion Control Team Lead or Engineer shall organize a stakeholder's meeting for discussion and review the schedule, requirements, safety requirements and safety awareness.

7.4.3 Requirements for the excavation schedule are provided below (subject to in-process evaluation and Reprioritization) determined from the date of Indication Prioritization.

- **Immediate -** Excavations shall be conducted within one month of the Indication Prioritization.
- **Scheduled -** Excavations shall be conducted within three months of Indication Prioritization.
- **Suitable for Monitoring -** Excavations shall be conducted within six months of Indication Prioritization.

7.5 Excavations and Data Collection

7.5.1 A qualified representative of MPLX shall be present during all excavations. A qualified representative includes the Integrity Engineer, Regional Corrosion Control Team Lead or Engineer, or an individual deemed acceptable by any of those individuals. The representative shall be responsible for ensuring all work is performed as per MPLX procedures during excavations and data collection. Care shall be taken during the excavation to avoid damaging the pipeline coating and removing any Corrosion or protective products that are critical to the overall analysis.

7.5.2 The Inspector (per Table 2) is responsible for data collection during the Direct Examinations. Data collected during each Direct Examination shall be documented using OPS-STD-0027-FOR-06. Data collected shall be verified and approved by the Integrity Engineer. One form shall be completed per Direct Examination. Relevant data listed on the form shall be collected. In addition, the following guidelines shall be adhered to:

- The location and size of the excavation site shall be identified and recorded. The length of the exposed pipe shall be physically measured and recorded. The length of the excavations for Direct Examination shall be 10 feet at a minimum.
- A minimum of two (2) soil samples shall be collected at each excavation site. One of the samples shall be representative of the native soil at pipe depth (i.e. to be obtained from the ditch wall perpendicular to the pipe), while the other shall be collected Immediately adjacent to the pipe and preferably near the Anomaly(s) that poses the greatest risk under investigation.
- The soil resistivity perpendicular to the pipe shall be measured using the Wenner 4-pin method if resistivity measurements were not collected during Indirect Inspections or if soil conditions have changed significantly between tests (i.e. season change).

7.6 Coating Damage and External Metal Loss Data Collection

7.6.1 Examination of the coating surface shall begin as soon as possible after the pipeline is exposed and the ditch is made safe to enter. Data collected during each Direct Examination shall be documented using OPS-STD-0027-FOR-06. The following shall be adhered to during coating and pipe surface examination:

- If Corrosion by-products are present on the pipe surface, the products shall be analyzed with field chemical testing for pH and specific ions (iron, carbonates, and sulfides).
- The coating condition shall be recorded. The coating condition evaluation includes such observations as blistering and lack of adhesion. The area

of any pipeline with no coating, loosely adhered coating and Disbonded Coating shall be estimated. Viable qualitative adhesion tests shall be performed. The coating shall also be inspected for the presence of Holidays and for coating thickness. All coating conditions, observations, and measurements shall be documented.

- A coating sample shall be obtained carefully using a clean knife to expose the steel beneath the coating. Coating samples shall be placed in sealed plastic bags identified by dig location, sample location, date, and person gathering the samples. All areas where coating samples were taken share be repaired.
    - o No coating samples will be needed if the coating is intact and well adhered to the pipe surface.
- If liquid or moisture is present on the pipe surface, the pH of the liquid shall be measured; however, in case of no liquid or moisture, addition of deionized water shall be used to measure the pH on the pipe surface.
- In case of any coating damage or coating Holiday, the coating shall be removed in order to perform pipe wall examination for Corrosion or Mechanical Damage. Attention shall be paid to correlate any possible relationship between coating and pipeline surface damages. Any such observations shall be documented.
- Structure-to-Electrolyte potentials (both potential with CP current applied and polarized potential) shall be taken at grade and above and below the pipe at both the upstream and downstream ends of the excavation.
- Pipe wall thickness measurements, at all four quadrants (3, 6, 9 and 12 o'clock) and at upstream and downstream ends, shall be measured to obtain reliable and actual wall thickness.
    - o If the ends are underneath well adhered coating, wall thickness readings shall be made at the Indication location.
- The presence of any external metal loss shall be documented. The external metal loss shall be characterized as general, localized or pitting. Data collection for external metal loss shall be in accordance with the MPLX Integrity Management Plan. At a minimum, the length, width, and depth of the external metal loss, as defined in the Remedial Actions Procedure, shall be recorded. The Integrity Engineer shall be Immediately notified if this condition is found.

7.6.2 Photographs of examination findings shall be collected. This includes finding the pipe exposed in good condition and/or free of anomalies.

7.6.3 The Integrity Engineer shall verify that the number of digs performed is in accordance with the required number of Direct Examinations. The Integrity Engineer shall also record the final date of completion of the Direct Examinations.

7.7 Remaining Strength Evaluation

7.7.1 Where external metal loss anomalies are found, a remaining strength calculation shall be completed. The Integrity Engineer shall classify the need for remedial action based on the remaining strength evaluation and observed conditions. All remedial actions are to be completed in response to the remaining strength and observed conditions are in accordance with the MPLX Integrity Management Plan. The Regional Corrosion Control Team Lead or

Engineer determines any necessary additional actions to assess the integrity of the Pipeline.

7.8 In Process Evaluation

7.8.1 The Integrity Engineer shall evaluate the Indirect Inspection data, Direct Examination data, and remaining strength analyses to evaluate the criteria used to assign Indication severity and excavation Prioritization. The data shall also be assessed with respect to the effectiveness of each Indirect Inspection survey to detect and characterize the extent of Corrosion Activity when found.

7.8.2 Corrosion Activity, when found, at each excavation shall be compared relative to the Indication Severity Classification. If the external metal loss due to Corrosion Activity identified during the Direct Examination is worse than indicated by the Indirect Inspection data, the criteria shall be modified, and the Indications shall be reclassified. Likewise, if the external metal loss due to Corrosion Activity is less than indicated by the Indirect Inspection data, the criteria may be modified, and the Indications be reclassified.

Table 9 Responses to Evaluation of Classification Criteria

	Finding	Change to Severity Criteria
Severe	Ongoing Corrosion Activity and Immediate threat	None
	Possible ongoing Corrosion Activity but not an Immediate threat	May relax and reclassify
	No ongoing Corrosion and not an Immediate threat	May relax and reclassify
	No coating Fault or metal loss	Re-evaluate inspection tool sensitivity
Moderate	Ongoing Corrosion Activity	Must revise and reclassify
	Possible ongoing Corrosion Activity	None
	No ongoing Corrosion Activity	May relax and reclassify
	No coating Fault or metal loss	Re-evaluate inspection tool sensitivity
Minor	Ongoing Corrosion Activity	Must revise and reclassify
	Possible ongoing Corrosion Activity	Must revise and reclassify
	No ongoing Corrosion Activity	None
	No coating Fault or metal loss	None
No Indication	Ongoing Corrosion Activity	Must re-evaluate ECDA feasibility; consider alternative assessment methods, or similar
	Possible ongoing Corrosion Activity	May re-evaluate ECDA feasibility and/or choice of Indirect Inspection tools; consider alternative assessment methods, or similar
	No ongoing Corrosion Activity	None
	No coating Fault or metal loss	None

7.8.3 In addition, the extent and severity of existing Corrosion Activity relative to the criteria used for excavation Prioritization shall be compared. Similar to the Classification criteria, if Corrosion Activity is more or less extensive than indicated by the criteria used to prioritize examinations, modification may be required. If the Prioritization criteria are changed, the Indication shall be reprioritized. When determining Reprioritization, it must be noted that Corrosion Activity may not have associated metal loss. Corrosion Activity includes areas of the pipe surface that are corroding, yet may not have measurable metal loss.

Table 10 Responses to Evaluation of Excavation Priority Criteria

	Initial Finding	Change to Excavation Priority Criteria
Immediate	Ongoing Corrosion Activity and Immediate threat	None
	Possible ongoing Corrosion Activity but not an Immediate threat	May relax and reprioritize
	No ongoing Corrosion and not an Immediate threat	May relax and reprioritize
	No coating Fault or metal loss	Re-evaluate inspection tool sensitivity
Scheduled	Ongoing Corrosion Activity	Must revise and reprioritize
	Possible ongoing Corrosion Activity but not an Immediate threat	None
	No ongoing Corrosion Activity	May relax and reprioritize
	No coating Fault or metal loss	Re-evaluate inspection tool sensitivity
Monitored	Ongoing Corrosion Activity and Immediate threat	Must revise and reprioritize
	Possible ongoing Corrosion Activity but not an Immediate threat	Must revise and reprioritize
	No ongoing Corrosion and not an Immediate threat	None
	No coating Fault or metal loss	None
No Indication	Ongoing Corrosion Activity and Immediate threat	Must re-evaluate ECDA feasibility; consider alternative assessment methods, or similar
	Possible ongoing Corrosion Activity but not an Immediate threat	May re-evaluate ECDA feasibility and/or choice of Indirect Inspection tools; consider alternative assessment methods, or similar
	No ongoing Corrosion and not an Immediate threat	None
	No coating Fault or metal loss	None
Any	Other Defects (SCC, Mechanical Damage)	Additional Reporting and assessments

7.8.4 The Integrity Engineer shall be responsible reclassifying and reprioritizing any Indications. All changes shall be technically justified and documented. If conditions are observed for which ECDA is not designed to mitigate, a determination shall be made if ECDA is an applicable integrity assessment method for the Pipeline Segment. All in-process evaluation activities shall be verified and approved by the Regional Corrosion Control Team Lead or Engineer .

7.8.5 Re-Classification and Reprioritization shall meet the following requirements:

- Indications that were originally in the Immediate category may be moved no lower than the Scheduled category.
- Indications that were originally in the Scheduled category may be moved no lower than the Suitable for Monitoring category.

7.8.6 The Regional Corrosion Control Team Lead or Engineer must verify and approve any Reclassification and/or Reprioritization.

7.9 Additional Considerations for First Time Application

7.9.1 One or more of the following tasks shall be completed when applying ECDA on a Pipeline Segment for the first time:

- Resurvey each ECDA Region after Immediate Indications are repaired to determine if other Indications were being masked.
- Perform Direct Examinations at a location with possible third-party damage.
- Perform additional NDE (Magnetic Particle Examination, X-Ray, or scanning UT) at Direct Examinations.
- Extend the length of the pipe under Direct Examination.

7.9.2 During Reclassification or Reprioritization per Section 7.8, Indications shall not downgraded during first time applications.

8.0 POST-ASSESSMENT

8.1 Purpose

8.1.1 The purpose of the Post-Assessment is to define re-assessment intervals, determine the need to reprioritize Indications, and assess the effectiveness of the ECDA process. The Post-Assessment Step includes the following activities:

- Root-cause analysis.
- Determining mitigation.
- Reprioritization.
- Remaining life calculations.
- Definition of re-assessment intervals.
- Assessment of ECDA effectiveness.
- Feedback for continuous improvement.

8.1.2 Upon completion of the project, the Integrity Engineer shall be responsible for compiling and submitting to the Regional Corrosion Control Team Lead or Engineer a final report, summarizing all phases of the project. The Regional Corrosion Control Team Lead or Engineer shall review the report findings. The report shall also include all supporting documentation.

8.1.3 Upon receipt of the report, the Regional Corrosion Control Team Lead or Engineer shall review the report and create an action plan for addressing any un-resolved issues. Any action plans shall be included in the final report. This action plan and the report shall be submitted to the Regional Corrosion Control Team Lead or Engineer for approval.

8.2 Root Cause Analysis

8.2.1 The Integrity Engineer shall be responsible for ensuring that a direct Root-Cause Analysis is performed to investigate all Corrosion Activity or significant external metal loss observed. Significant metal loss includes any Anomaly with greater than 20 percent nominal wall thickness loss. A direct Root-Cause Analysis may include, but is not limited to, insufficient Cathodic Protection, Stray Currents or electrical interference (not previously identified), and Shielding of Cathodic Protection due to Disbonded Coatings.

8.2.2 The results from the Direct Examinations (i.e., visual inspection of coating and pipe surface, Corrosion product analysis, soil resistivity measurements, structure-to-Electrolyte potentials, pH, etc.) shall be aligned and used to help determine the direct root cause.

8.2.3 The analysis shall include the following aspects, where applicable:

- **Coating Damage –** The analysis identifies the extent and reason for the coating damage, including discussion regarding whether the damage is associated with installation or if it is a result of a failure of the coating system.
- **Cathodic Protection Ineffectiveness –** The analysis may discuss why the CP was ineffective in this area. The analysis also includes a discussion of CP history in the area, and the reasons for the presence of CP current Shielding or Stray Currents.
- **Possible Corrosion Mechanism(s) –** The analysis identifies the main drivers for Corrosion, when found, in the area including soil chemistry, pH, moisture, corrosive microbes, etc. The analysis also determines if the observed Corrosion appears to be Active or historic.
- **Corrosion Characteristics at Other Locations –** The analysis discusses the characteristics of other locations where similar Corrosion Activity may be found.
- **Mitigative Measures –** The analysis identifies potential measures to mitigate Corrosion Activity at the particular location.

8.2.4 If a direct Root-Cause Analysis uncovers a cause for which ECDA is not well suited (e.g. Shielding due to Disbonded Coating), the Integrity Engineer shall consider alternative methods of addressing the integrity of the Pipeline Segment.

8.2.5 The Integrity Engineer shall be responsible for identifying all other Indications within the Pipeline Segment where similar conditions may exist. If it is determined that other Indications exist with similar conditions, these Indications shall be evaluated. The Integrity Engineer shall document the direct Root-Cause Analysis. The analysis shall be verified and approved by the Regional Corrosion Control Team Lead or Engineer .

8.3 Determining Mitigation

8.3.1 After identifying the direct Root-Causes of the discovered conditions, mitigative actions must be established to preclude future External Corrosion. The Integrity Engineer shall prepare a list of mitigative actions as part of the Post-Assessment Step. Remedial actions shall be completed in accordance with the MPLX Integrity Management Plan.

8.3.2 The Regional Corrosion Control Team Lead or Engineer shall document what remedial actions are completed including when the action items are completed.

8.4 Reclassification and Reprioritization

8.4.1 Calculation Methodology

8.4.2.1 The Integrity Engineer shall be responsible to ensuring that remaining life calculations are conducted when Corrosion damage is found on the pipeline. If no Corrosion damage is found, the remaining life of the pipeline is taken as that of a new pipeline. The maximum remaining flaw size at all Scheduled Indications is taken as the same as the Anomaly that poses the greatest risk in all locations that have been excavated and is used in determining remaining life.

8.4.2.2 The remaining life is established by selecting the shortest value between "Time-to-Leak" (TL) and "Time-to-Failure" (TF) calculations. The relevant equations for TF and TL are:

$$TF = C \times SM \frac{t}{GR} \qquad TL = \frac{0.8 * t - d}{GR} \qquad (2)$$

Where:

C = Calibration Factor = 0.85 (dimensionless)

TF = Time until Failure (years)

TL = Time until Leak (years) (Grown to a maximum 80% deep Defect representing an Immediate condition)

SMYS = Specified Minimum Yield Strength (PSI)

IDP = Internal Design Pressure (PSI)

MOP = Maximum Operating Pressure (PSI) of the Pipeline Segment

P_{burst} = Predicted Burst Pressure (PSIG) using B31G modified method

MPR = MOP Ratio = MOP/YP

RPR = Rupture Pressure Ratio = P_{burst}/YP

SM = Safety Margin = RPR - MPR

t = Nominal Wall Thickness (inches)

d = Corrosion depth (inches)

OD = Outside Diameter (inches)

GR = Growth Rate (inches per year)

YP = Yield Pressure (Pressure to produce stress equal to 100% SMYS)

8.4.2 External Corrosion Rate Determination

8.4.2.1 The External Corrosion growth rate is an essential variable needed for the calculation of the remaining life of a Pipeline Segment. Actual Corrosion rates are difficult to predict or to measure, since the actual conditions at all locations where Corrosion may be occurring are not known. The growth rate used in the remaining life calculation is based on actual Corrosion rate data applicable to the ECDA Region if available. If actual data cannot be collected, the following methods shall be considered:

- Method 1 – Historical Corrosion growth rates can be utilized for pipelines with similar characteristics (coating, CP, wall thickness, grade) installed in similar environments (terrain, soil type, drainage). Buried Corrosion coupon data if available can also be used to estimate Corrosion rates.

- Method 2 – Linear growth rates (or alternative modeling) can be used to establish the annual Corrosion growth of External Corrosion anomalies based on the peak metal loss depth divided by the years of exposure (Years since installation).
- Method 3 – If no known Corrosion growth rate information is available, and it cannot be approximated by any of the above three methods, industry published Corrosion growth rate data can be relied upon.

8.5 Definition of Re-Assessment Interval

8.5.1 Re-assessment is a crucial element in maintaining an effective integrity management process. The maximum re-assessment interval shall be the lessor of the half-life of the Pipeline Segment section with the smallest remaining life or the set maximum interval provided in 8.5.2.1. The beginning of the re-assessment interval is the date on which the last Direct Examination was completed.

8.5.2 Half-Life Re-Assessment Interval

8.5.2.1 The re-assessment interval is one half the remaining life of any section of the Pipeline Segment. The remaining life is the lesser of the "Time-to-Failure" or "Time-to-Leak" calculated in 8.4.2.2.

8.5.3 Set Maximum Re-Assessment Interval

8.5.2.1 The maximum re-assessment interval shall be five (5) years, not to exceed 68 months.

8.5.2.2 Any Indications that are prioritized as Scheduled for Evaluation shall be addressed before the next re-assessment interval.

8.5.2.3 The Integrity Engineer shall evaluate whether or not conditions discovered during the Direct Examinations indicate a need to re-assess the Pipeline Segment at a shorter interval. The re-assessment interval shall be documented in OPS-STD-0027-FOR-07. The Regional Corrosion Control Team Lead or Engineer shall review and approve the final re-assessment interval. The Regional Corrosion Control Team Lead or Engineer must verify communication is made to operations, the compliance group, the health and safety group, the integrity group, the maintenance group, and the Corrosion group.

8.6 ECDA Effectiveness

8.6.1 Process Validation

8.6.2.1 Additional process validation excavations shall be required as part of the Post-Assessment. While data from these excavations will be analyzed separately, the validation excavations shall be planned as part of the Direct Examinations as all excavations will likely occur within the same timeframe.

8.6.2.2 At least one (1) additional Direct Examination in the Pipeline Segment shall be performed at a random location to validate the process.

8.6.2.3 At least two additional Direct Examinations shall be required for process validation if applying ECDA for the first time. The Direct Examinations shall be performed at randomly selected locations, one of which contains a Scheduled Indication (or Monitored Indication if no Scheduled Indications exist) and one in an area where no Indication was detected. Additional validation Direct Examinations shall also be documented in OPS-STD-0027-FOR-06. The condition observed at this location shall be compared to Indications of the same severity level. If conditions are or greater risk than determined during the ECDA process, the validation process shall be re-evaluated and repeated. The reason(s) for the discrepancy shall be established. If the process cannot be validated using this process, then ECDA may be unfeasible to evaluate the impact of External Corrosion on the integrity of the Pipeline Segment.

8.6.2 Long-Term Effectiveness

8.6.2.1 ECDA is a continuous improvement process. As such, criteria shall be used to determine its long-term effectiveness. Performance measures shall include the following:

- Repeatability and Consistency – Tracking the reliability and repeatability of the results and/or the number of Reclassifications and Reprioritizations.
- Application – Tracking the number of excavations, total miles inspected, and/or number of miles subjected to Indirect Inspection.
- ECDA Results.
  - Tracking and comparing the frequency with which anomalies in the Immediate and Scheduled categories occur.
  - Tracking the extent and severity of Corrosion for each ECDA Region.
  - Tracking how frequently anomalies occur in a given Region, documenting both time and location of each Anomaly measured.
  - Tracking the number of repairs completed at each Prioritization level of Indication.
  - Tracking the number of failures.

8.6.2.2 In addition, absolute criteria may be established to assess ECDA effectiveness. For example, a minimum performance requirement, such as no leak or rupture before the next re-assessment interval may be used. All identified locations of any Corrosion Activity must be addressed.

8.6.2.3 The Regional Corrosion Control Team Lead or Engineer shall be responsible for ensuring that criteria are used to evaluate ECDA effectiveness. If the evaluation does not show improvement between applications, measures shall be taken to re-evaluate the ECDA application process or consider alternative methods. The completion and outcome of the validation study and any specific comments shall be documented in the Final Report. The process validation shall be completed by the Integrity Engineer, and the Regional Corrosion Control Team Lead or Engineer shall review the findings.

8.7 Feedback and Continuous Improvement

8.7.1 The Regional Corrosion Control Team Lead or Engineer shall be responsible for ensuring that actions are taken to continuously improve the application of the ECDA process through a timely and quality-oriented feedback. The following types of feedback shall be considered:

- Identification and Classification of Indirect Inspection results.
- Data collection methods and effectiveness.
- Remaining strength evaluation.
- Direct Root-Cause Analysis.
- Mitigation.
- In-process evaluation.
- Additional Direct Examination for process validation.
- Additional criteria for assessing the ECDA effectiveness.
- Proper scheduling and monitoring of the re-assessment intervals for ensuring the long-term effectiveness of the ECDA process.
- Lessons learned.

8.7.2 The Integrity Engineer shall be responsible for summarizing feedback and continuous comments for each project. These findings shall be verified and approved by the Regional Corrosion Control Team Lead or Engineer . All feedback or continuous improvement suggestions shall be documented by the Integrity Engineer as part of the final report.

8.7.3 The Regional Corrosion Control Team Lead or Engineer shall be responsible for tracking changes to this standard as a result of the feedback. The Regional Corrosion Control Team Lead or Engineer shall be responsible for informing project teams of the changes between projects. During projects, it is the responsibility of the Regional Corrosion Control Team Lead or Engineer to inform team members of changes to the ECDA process.

8.8 Additional Considerations for First Time Application

8.8.1 These requirements shall include the following for the Post-Assessment step:

- Comparing the results of this ECDA to other Pipeline Segments that operate under similar conditions.

9.0 SURVEY RECORD KEEPING

9.1 In accordance with this standard, the Integrity Engineer shall be responsible for documenting forms, reports, and supporting data. This includes the approval of the ECDA process. Approval for the use of this ECDA process is located in the MPLX Integrity Management Plan. This documentation shall be submitted to the Regional Corrosion Control Team Lead or Engineer for verification and approval. This shall be completed following each of the four steps of the ECDA process. Following the verification of all forms and reports, the Regional Corrosion Control Team Lead or Engineer shall be responsible for storing all documentation. Documentation shall have required signatures prior to storage. All documentation for an ECDA project shall be stored in the Documents folder located on the Logistics network drive and maintained for the life of the asset.

Below is a summary of the data, forms, and reports that are to be documented throughout the process.

9.1.1 Project

- ECDA Process Form:
  - To act as a supplement to the Integrity Assessment Form
  - To be used for approval of the project and a guide throughout the process.
  - This form also acts a checklist for the process to ensure all activities are completed and documented.

9.1.2 Pre-Assessment

- ECDA Data Collection Form (cased and uncased version).
- Indirect Inspection Tool Selection Form (cased and uncased version).
- ECDA Region Analysis Form (cased and uncased version).
- Indirect Inspection Plan.
- Pre-Assessment data collected.
  - Includes assumptions made about data elements.
  - Technical justification used during tool selection.
- Documentation of justification for ECDA feasibility.

9.1.3 Indirect Inspection

- Raw Survey data.
- Aligned Survey data.
- Indication Severity Classification Form.
  - Documentation of criteria used with supporting justification.

9.1.4 Direct Examination

- Indication Severity Classification Form (Prioritization Column).
  - Documentation of criteria used with supporting justification.
- Excavation Summary.
- Field Data Collected.
- Remaining Strength.
- Documented In-Process Evaluation
  - Includes technical justification.

9.1.5 Post-Assessment

- Final Report
  - Summary of Pre-Assessment.
  - Summary of Indirect Inspection.
  - Summary of Direct Examination.
  - Root Cause Analysis.
  - Mitigation.

- Reprioritization.
- Remaining Life.
- Re-Assessment Interval.
- ECDA Effectiveness.
- Feedback for continuous improvement.
- Recommendations.

APPENDIX A – ECDA PROCESS FLOW CHARTS

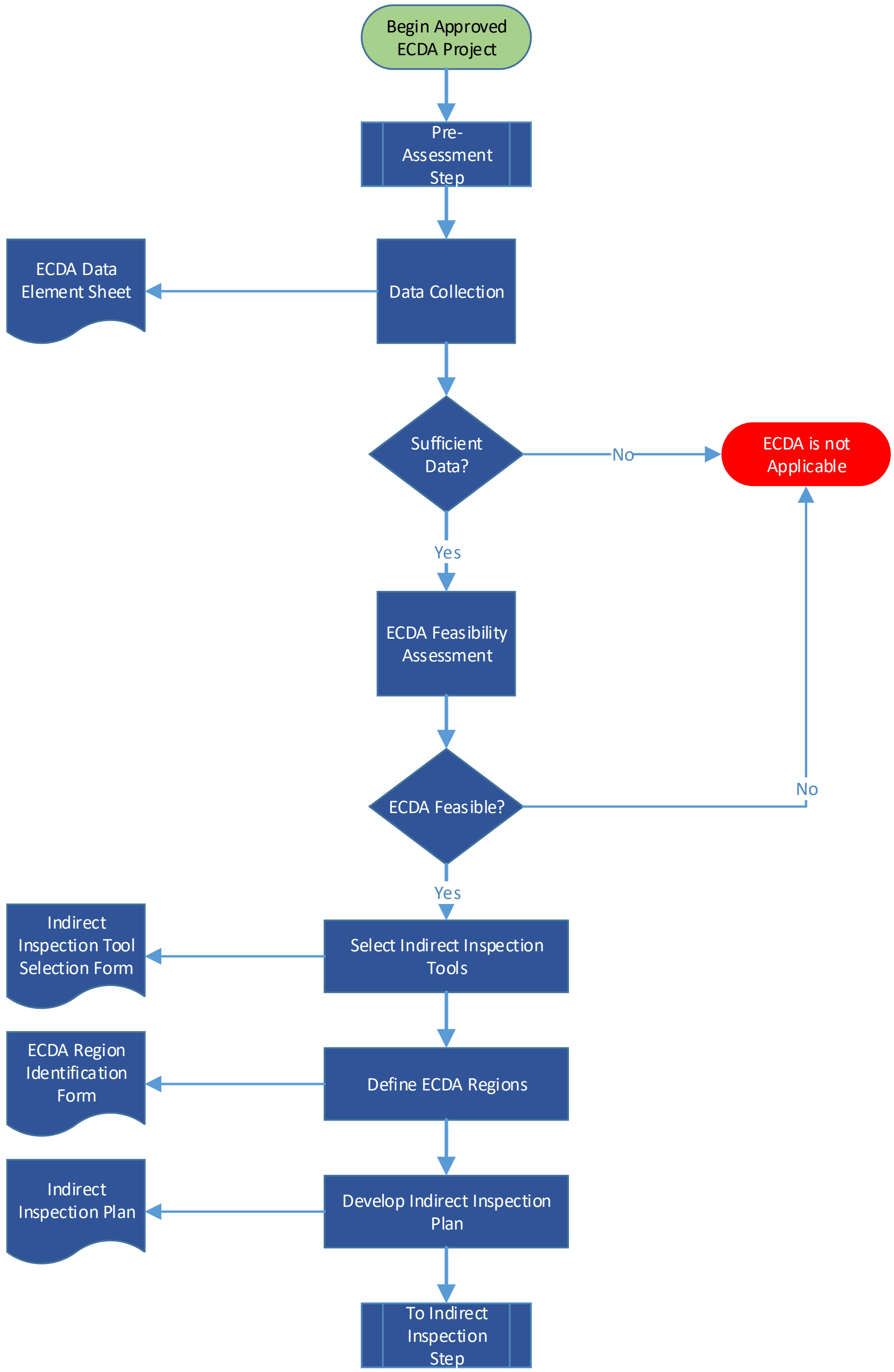


Figure 1 ECDA Pre-Assessment Step Flow Chart

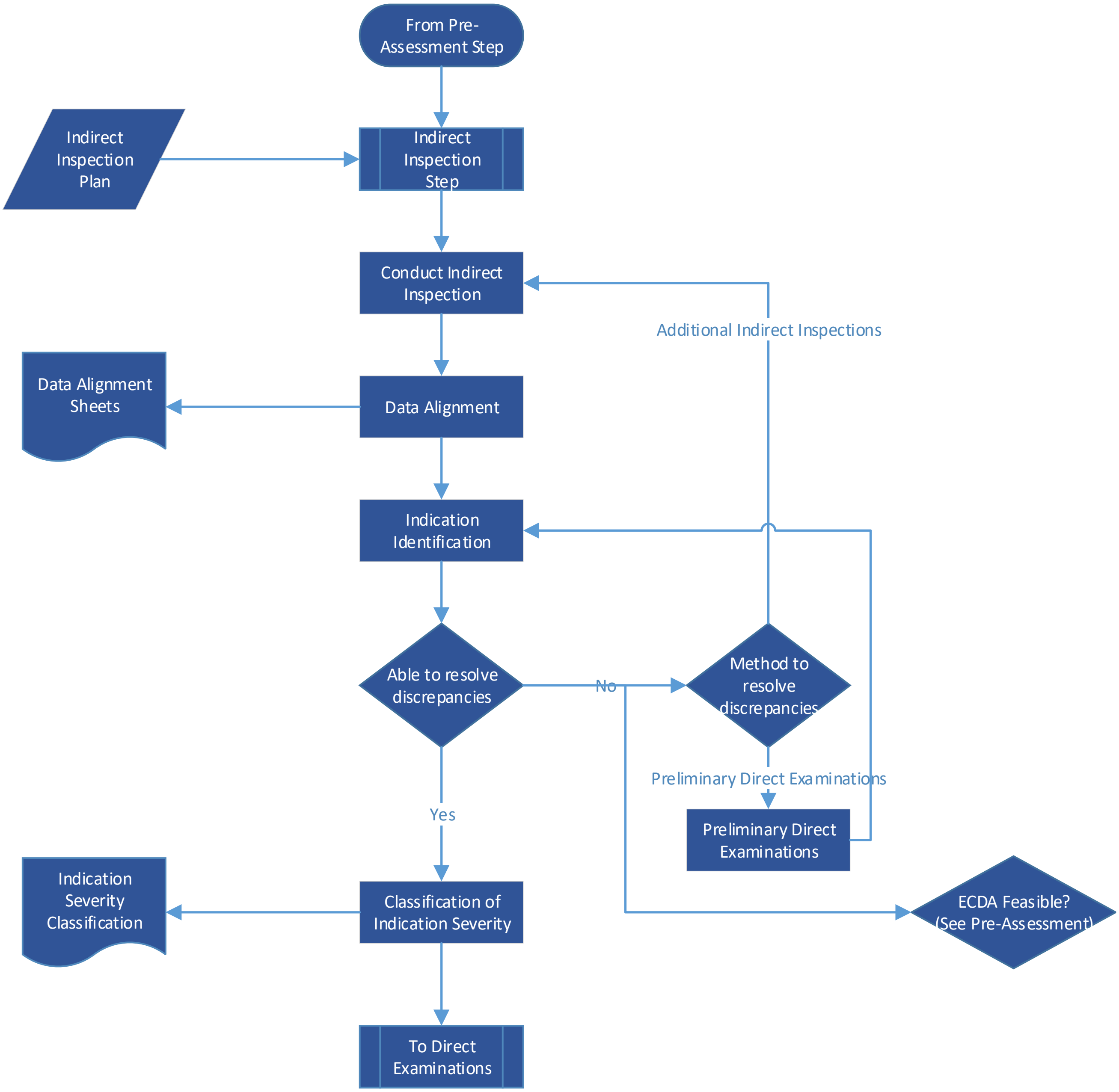


Figure 2 ECDA Indirect Inspection Step Flow Chart

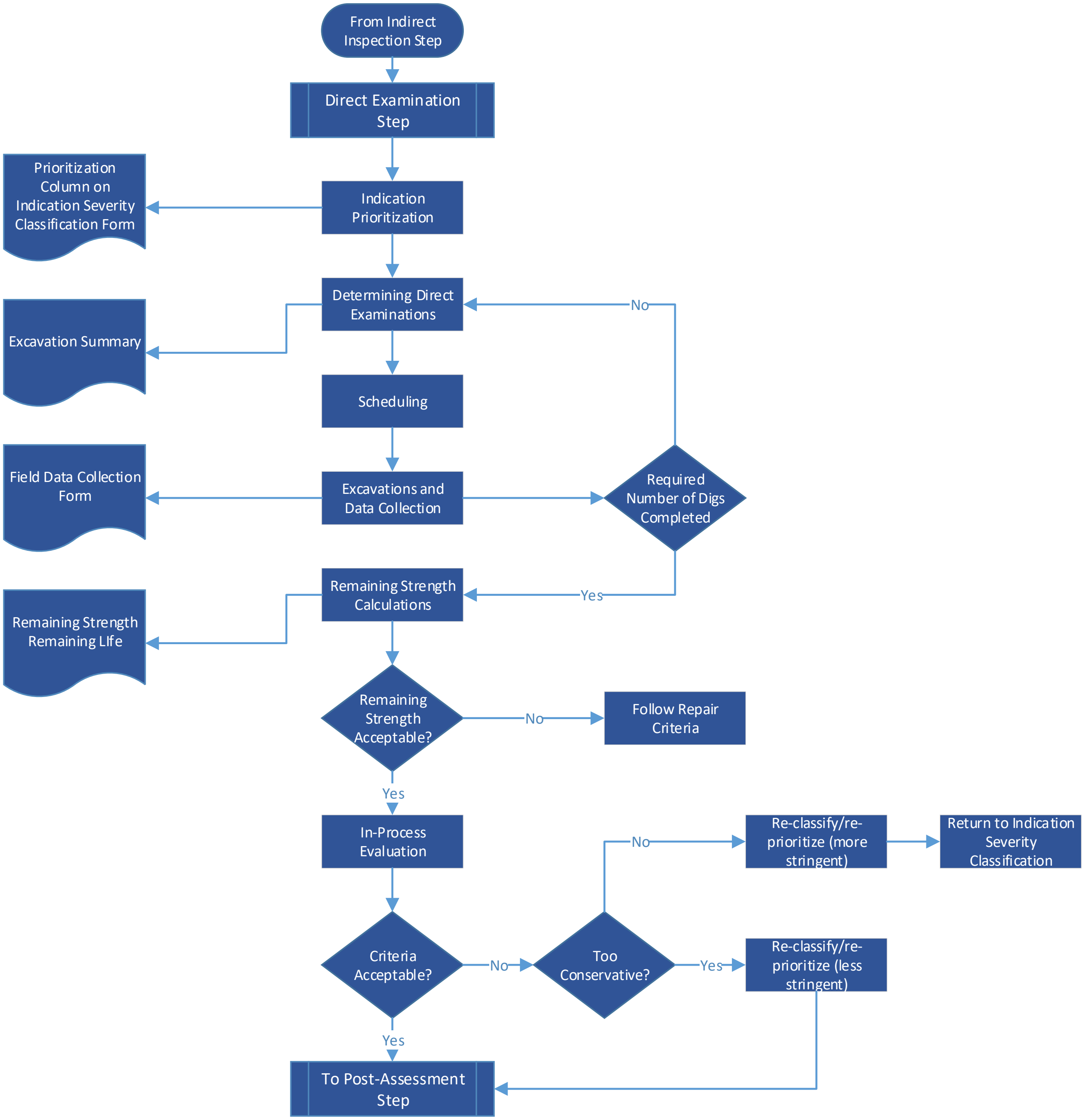


Figure 3 ECDA Direct Examination Step Flow Chart

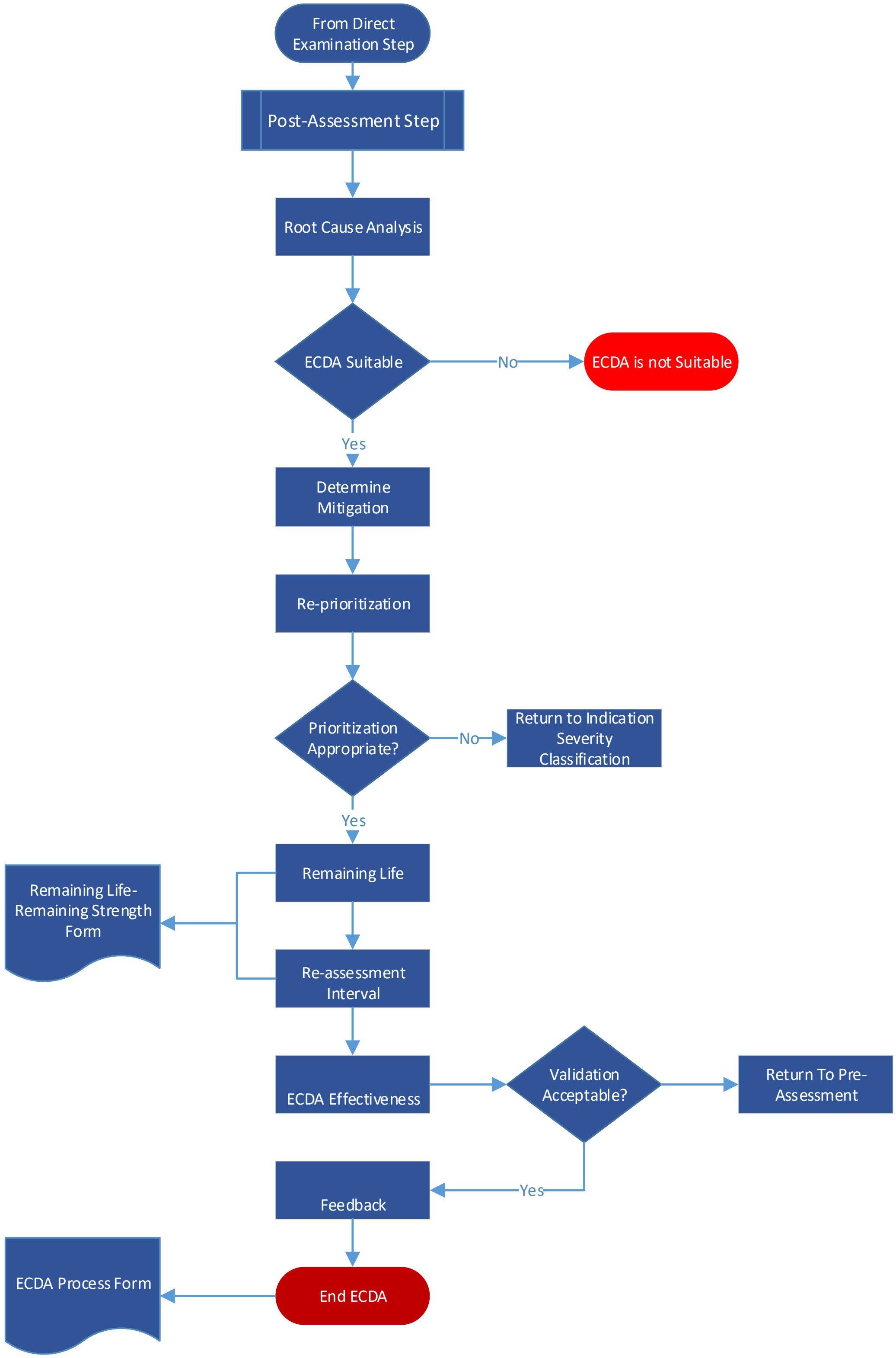


Figure 4 ECDA Post-Assessment Step Flow Chart

	ECDA Process	OPS-STD-0027-FOR-01	
	FORM	Page 1 of 6	
		DATE: 4/1/2021	Rev: 0

ECDA Project Information
ECDA Project Identification:
Pipeline Identification:
Segment Identification:

This form is to be used as a supplement to the Integrity Assessment Form (LIM030-F1). When conducting an ECDA Project both forms must be completed. The form includes a section for each step of the ECDA process. Each section contains a list of activities for each step, a list of required forms and documentation, a section to enter what criteria has been used for a first-time application project, and a verification section for the responsible individuals.

Form Sections:

1. Pre-Assessment Step
2. Indirect Inspection Step
3. Direct Examination Step
4. Post-Assessment Step

1) Pre-Assessment Step

Step Activities

The Pre-Assessment Step includes the following activities:

- Data collection
- Assessment of ECDA feasibility
- Selection of indirect inspection tools
- Identification of ECDA regions
- Development of an Indirect Inspection Plan

Forms and Documentation

The Pre-Assessment Step Requires the following documentation:

- ☐ Relevant data collected
- ☐ ECDA Data Elements Form
- ☐ Technical justification for ECDA feasibility
- ☐ Indirect Inspection Tool Selection Form with attached justification
- ☐ ECDA Region Identification Form
- ☐ Indirect Inspection Plan

First Time Application

What additional criteria were applied for the first time application? (If not first application, N/A)

Verification and Approval

Integrity Engineer: *All required items have been documented.*

Signature:	Date:

Regional Corrosion Control Team Lead or Engineer:
Documentation, Forms, and Conclusions have been verified.

Signature:	Date:

2) Indirect Inspection Step

Step Activities

The Indirect Inspection Step includes the following activities:

- Conducting the indirect inspections
- Data alignment
- Identification of indications
- Classification of indication severity

Forms and Documentation

The Indirect Inspection Step Requires the following documentation:

- ☐ Indirect inspection survey data
- ☐ Aligned data
- ☐ Criteria for identify indications
- ☐ Criteria for classifying indications
- ☐ Indication Severity Classification Form (except for Prioritization column)

First Time Application

What additional criteria were applied for the first time application? (If not first application, N/A)

Verification and Approval

Integrity Engineer: *All required items have been documented.*

Signature:	Date:

Regional Corrosion Control Team Lead or Engineer :
Documentation, Forms, and Conclusions have been verified.

Signature:	Date:

MPLX	ECDA Process	OPS-STD-0027-FOR-01	
	FORM	Page 4 of 6	
		DATE: 4/1/2021	Rev: 0

3) Direct Examination Step

Step Activities

The Direct Examination Step includes the following activities:

- Indication prioritization
- Determining the required number of excavation for direct examination
- Scheduling excavations
- Excavation and data collection
- Corrosion damage and corrosion data collection
- Remaining strength evaluation
- In-process evaluation

Forms and Documentation

The Direct Examination Step Requires the following documentation:

- ☐ Indication Severity Classification Form (Prioritization column)
- ☐ Criteria for indication prioritization
- ☐ Excavation Summary Form
- ☐ Excavation Data Collection Form(s)
- ☐ Remaining Strength/Remaining Life Form
- ☐ In-process evaluation

First Time Application

What additional criteria were applied for the first time application? (If not first application, N/A)

Verification and Approval

Integrity Engineer: *All required items have been documented.*

Signature:	Date:

Regional Corrosion Control Team Lead or Engineer :
Documentation, Forms, and Conclusions have been verified.

Signature:	Date:

4) Post-Assessment Step

Step Activities

The Post-Assessment Step includes the following activities:

- Root-cause analysis
- Determining mitigation
- Reprioritization
- Remaining life calculations
- Definition of re-assessment intervals
- Assessment of ECDA effectiveness
- Feedback for continuous improvement

Forms and Documentation

The Post-Assessment Step Requires the following documentation, will are included in a single final report:

- ☐ Root cause analysis conclusions
- ☐ Mitigative activities
- ☐ Reprioritization justification
- ☐ Remaining Strength/Remaining Life Form
- ☐ Define re-assessment interval
- ☐ ECDA effectiveness
- ☐ Feedback
- ☐ Recommendations
- ☐ Summary of each ECDA step
- ☐ Integrity Assessment Form (LIM030-F1)

First Time Application

What additional criteria were applied for the first time application? (If not first application, N/A)

Verification and Approval

Integrity Engineer: *All required items have been documented*

Signature:	Date:

Regional Corrosion Control Team Lead or Engineer

4) Post-Assessment Step	
Documentation, Forms, and Conclusions have been verified. Approval of Re-Assessment Interval.	
Signature:	Date:

	Operating Standard	OPS-STD-0028	
	Stress Corrosion Cracking Direct Assessment	**Page 1 of 37**	
		DATE: 4/1/2021	**Rev:** 0

Contents

List of Figures

List of Tables

Revision:	Prepared by:	Approved by:	Issue Date:
0	Ryan Ell	Scott Stampka	4/1/2021

1.0 INTRODUCTION

1.1 Purpose

1.1.1 This Standard establishes minimum requirements for Stress Corrosion Cracking Direct Assessment (SSCDA) of pipelines to provide:

- Compliance with regulatory requirements (for pipeline systems and facilities).
- The intended service life as well as to streamline all requirements through the standardization of survey procedures, materials, and inspection requirements as they pertain to the mitigation of Stress Corrosion Cracking (SSC).

1.2 Scope

1.2.1 This Standard applies to all MPLX Petroleum Logistics (MPLX) Gathering and Processing (G&P) operated assets that fall under the Integrity Management Program (IMP) that are not assessed for integrity by means of inline inspection or hydrotest.

2.0 REFERENCES

2.1 MPLX Standards

- OPS-STD-0017 Corrosion Control Governing Standard
- OPS-STD-0027-FOR-03 ECDA/SCCDA Indirect Inspection Tools Selection Form
- OPS-STD-0027-FOR-05 ECDA/SCCDA Indication Severity Classification Summary Form
- OPS-STD-0027-FOR-06 ECDA/SCCDA Dig Data Collection Form
- OPS-STD-0028-FOR-01 SCCDA Process Form
- OPS-STD-0028-FOR-02 SCCDA Data Elements Form
- OPS-STD-0028-FOR-03 SCCDA Region Analysis Form
- OPS-STD-0028-FOR-04 SCCDA Re-Assessment Interval Form
- LO-18.001-STD Integrity Management Plan Governing Standard
- MPLX Integrity Management Plan

2.2 Industry Codes and Standards

- ANST SNT-TC-1A Personnel Qualification and Certification in Nondestructive Testing
- ASME/ANSI B31.8S-2004. Managing System Integrity of Gas Pipelines (incorporated by reference in 49CFR 192 but not 49CFR195; SCCDA is considered an other technology in the liquid regulations)
- ASME/ANSI B31.8S-2012. Managing System Integrity of Gas Pipelines (not incorporated by reference in 49CFR 192 or 49CFR195)
- Canadian Energy Pipeline Association (CEPA), Stress Corrosion Cracking Recommended Practices, 2nd Edition, December 2007
- NACE SP0204-2008 Stress Corrosion Cracking Direct Assessment Methodology

2.3 Government Regulations

- PHMSA 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline
- PHMSA 49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline

2.4 Other

- TSCP-006 Cathodic Protection Survey Procedures

3.0 DEFINITIONS

The following additional definitions are applicable to this Standard.

Table 1 Definitions

Term	Description
Active	(1) A state of a metal surface that is corroding without significant influence of reaction product; (2) the negative direction of electrode potential.

Term	Description
Alternating Current Voltage Gradient (ACVG) Survey	A method of measuring the change in leakage current in the soil along and around a pipeline to locate coating Holidays and characterize Corrosion Activity.
Anomaly	Any deviation from nominal conditions in the external wall of a pipe, its coating, or the electromagnetic conditions around the pipe.
Cathodic Protection	A technique to reduce the Corrosion rate of a metal surface by making that surface the cathode of an electrochemical cell.
Classification	The process of estimating the likelihood of Corrosion Activity at an Indirect Inspection Indication under typical year-round conditions.
Close-Interval Survey	A method of measuring the potential between the pipe and earth at regular intervals along the pipeline.
Cluster	A grouping of stress Corrosion cracks (Colony). Typically, stress Corrosion cracks occur in groups consisting of hundreds or thousands of cracks within a relatively confined area.
Coalescence	Joining of two or more cracks that are in close proximity to form one larger crack.
Colony	A grouping of stress Corrosion cracks (Cluster). Typically, stress Corrosion cracks occur in groups consisting of hundreds or thousands of cracks within a relatively confined area. See Cluster.
Corrosion	The deterioration of a material, usually a metal, that results from a chemical or electrochemical reaction with its environment.
Corrosion Activity	A state in which Corrosion is Active and ongoing at a rate that is sufficient to reduce the pressure-carrying capacity of a pipe during the pipeline design life.
Critical Flaw Size	The dimensions (length and depth) of a flaw that would fail at a given level of pressure or stress.
Alternating Current Current Attenuation (ACCA) Survey	A method of measuring the overall condition of the coating on a pipeline based on the application of electromagnetic field propagation theory. Concomitant data collected may include depth, coating resistance and conductance, Anomaly location, and Anomaly type.
Defect	An Anomaly in the pipe wall that reduces the pressure-carrying capacity of the pipe. For the purposes of this document, any crack-like indication that is confirmed to be SCC is considered a Defect.
Direct Current Voltage Gradient Survey (DCVG)	A method of measuring the change in electrical voltage gradient in the soil along and around a pipeline to locate coating Holidays and characterize Corrosion Activity.
Direct Examination	Inspections and measurements made on the pipe surface at excavations as part of SCCDA.

Term	Description
Disbonded Coating	Any loss of adhesion between the protective coating and a pipe surface as a result of adhesive failure, chemical attack, mechanical damage, hydrogen concentrations, etc. Disbonded coating may or may not be associated with a coating Holiday.
Electrolyte	A chemical substance containing ions that migrate in an electric field. For the purposes of this standard, Electrolyte refers to the soil or liquid adjacent to and in contact with a buried metallic piping system, including the moisture and other chemicals contained therein.
External Corrosion Direct Assessment (ECDA)	A four-step process that combines pre-assessment, Indirect Inspection, Direct Examination, and post-assessment to evaluate the effect of External Corrosion on the integrity of a pipeline.
Fault	Any Anomaly in the coating, including disbonded areas and Holidays.
High Consequence Area	Location along the pipeline that meets the characteristics specified DOT Part 192.905, i.e., location where a pipeline release might have a significant adverse effect on a particularly sensitive area, a commercial waterway, or a high population or other populated area.
High-pH SCC	A form of SCC on underground pipelines that is intergranular and typically branched, and is associated with an alkaline Electrolyte (pH about 9.3).
Holiday	A discontinuity in a protective coating that exposes unprotected surface to the environment.
Indirect Inspection	Equipment and practices used to take measurements at ground surface above or near a pipeline to locate or characterize Corrosion Activity, coating Holidays, or other anomalies.
In-Line Inspection	The inspection of a pipeline from the interior of the pipe using an In-Line Inspection tool. The tools used to conduct ILI are known as *pigs* or *smart pigs*.
Intergranular Cracking	Cracking in which the crack path is between the grains of a metal (typically associated with High-pH SCC).
Low-pH SCC	See Near-Neutral-pH SCC.
Maximum Allowable Operating Pressure (MAOP)	The maximum internal pressure permitted during the operation of a pipeline.
MPLX	For the purpose of this standard, MPLX shall mean Andeavor, Markwest, and Southwest Gathering.
Near-Neutral-pH SCC	A form of SCC on underground pipelines that is transgranular and is associated with a near-neutral-pH Electrolyte. Typically this form of cracking has limited branching and is associated with some Corrosion of the crack walls and sometimes of the pipe surface.

Term	Description
Pipeline Segment	A portion of a pipeline that is (to be) assessed using SCCDA. A segment may consist of one or more SCCDA Regions.
Structure-to-Electrolyte Voltage (Also Structure-to-Soil Potential or Pipe-to-Soil Potential)	The voltage difference between a metallic structure and reference electrode in contact with a shared Electrolyte.
Predictive SCC Model	A model that predicts the SCC susceptibility of a segment of a pipeline based on factors such as Terrain Conditions (topography, drainage, and soil type), pipe characteristics, and operating and maintenance history.
Shielding	(1) Protecting; protective cover against mechanical damage; (2) preventing or diverting Cathodic Protection current from its natural path.
Sound Engineering Practice	Reasoning exhibited or based on thorough knowledge and experience, logically valid and having technically correct premises that demonstrate good judgment or sense in the application of science.
Stress Corrosion Cracking (SCC)	Cracking of a material produced by the combined action of Corrosion and sustained tensile stress (residual or applied).
Tenting	A tent-shaped void associated with tape coatings formed along the seam weld of a pipeline where the external coating bridges from the top of the weld to the pipe.
Terrain Conditions	Collective term used to describe soil type, drainage, and topography. Often used as input in the generation of SCC predictive models.
Transgranular Cracking	Cracking in which the crack path is through the grains of a metal (typically associated with Near-Neutral-pH SCC).

4.0 GENERAL REQUIREMENTS

4.1 Procedure

4.1.1 Individuals performing SCCDA survey work shall be qualified per the relevant OQ tasks specified in the MPLX OQ Plan.

4.1.2 SCCDA shall be performed in accordance with NACE SP0204-2015.

4.1.3 SCCDA is a structured four-step process for buried onshore piping systems. The intent of the SCCDA methodology is to identify and examine sites where SCC is more likely to occur, thereby providing insight into whether SCC is a threat to the pipeline. A brief description of the four steps in the SCCDA process is presented below:

Step 1 Pre-Assessment

Compile historic and current data to define SCCDA Regions and select appropriate Indirect Inspection tools. The types of data that are most important during the Pre-Assessment Step are typically available in construction records, operating and maintenance histories, alignment sheets, Corrosion survey records, other aboveground inspection records, and inspection reports from prior excavations, integrity evaluations, and maintenance actions.

Step 2 Indirect Inspection

Covers aboveground inspections to identify and define the severity of coating Faults, other anomalies, and areas where Corrosion Activity may have or may be occurring in the areas under investigation. Two or more complementary Indirect Inspection tools shall be used over the entire Pipeline Segment under investigation to provide improved detection accuracy under the wide variety of conditions that may be encountered along a pipeline right-of-way. The combination of Indirect Inspections may vary based on the characteristics of different regions that may exist along the Pipeline Segment being assessed.

Step 3 Direct Examination

Collection of data which, combined with prior data, are used to assess the impact of SCC on the pipeline.

Step 4 Post-Assessment

Analyses of data collected from the previous three steps to assess the effectiveness of the SCCDA program and determine re-assessment intervals.

4.1.4 The OPS-STD-0028-FOR-01 form shall be used when completing each step of the SCCDA process.

4.2 Qualifications

4.2.1 Qualifications for individuals involved in the SCCDA process are summarized in Table 2.

Table 2 Qualifications

Role	Qualifications
IMP Manager	An individual who possess a Bachelor of Science degree in engineering or technology, plus five years of experience in Corrosion engineering and SCC management programs. The individual must have sufficient pipeline experience related to external pipeline Corrosion to provide guidance and oversight to the personnel conducting the SCCDA process.
Regional Corrosion Control Team Lead	An individual who is qualified as an MPLX Regional Corrosion Control Team Lead or Engineer per the qualifications stated in Appendix D of OPS-STD-0017.
Integrity Engineer	An individual who possesses Bachelor of Science degree in engineering or technology, plus three years of pipeline-related engineering or have equivalent pipeline experience in the pipeline industry. This individual has training and experience on conducting remaining strength calculations for crack-like anomalies.
Corrosion Control Technician/Specialist/Engineer	An individual who is qualified through Corrosion Control OQ tasks or the equivalent NACE certifications per Appendix E of OPS-STD-0017.
Nondestructive Examination Specialist (Inspector)	An individual who meets Operator Qualification requirements and is an ANST SNT-TC-1A Level II NDT Examiner for any NDT task to be completed under this plan.

4.3 Equipment

4.3.1 The Integrity Engineer shall be responsible for ensuring all equipment used during the SCCDA process is used in accordance with MPLX field investigation and NDT procedures.

5.0 PRE-ASSESSMENT

5.1 Purpose

5.1.1 The purpose of the Pre-Assessment step is to collect sufficient pipeline data to identify SCCDA Regions and sites for possible Direct Examinations. The Pre-Assessment step shall contain the following activities:

- Data collection.
- Identification of SCCDA Regions.
- Development of an Indirect Inspection Plan.
- Selection of dig sites.

5.2 Data Collection

5.2.1 Historical and current data, including physical information, shall be collected for the Pipeline Segment. Minimum data collection requirements are based on the history and condition of the pipe. The L0-10.026-FOR02 form shall be used to collect relevant data. The form differentiates between Required, Desired, and Optional Data.

- **Required Data** is critical to completing the SCCDA process.
- **Desired Data** is relevant but not essential to the SCCDA process.
- **Optional Data** is typically informational.

5.2.2 Required Data elements shall be obtained before the completion of the Pre-Assessment step. Desired Data elements should be obtained if the data is available in existing records or they are reasonable to acquire through measurements or examinations.

5.2.3 In the event that data for a particular category is not available, conservative or best estimate assumptions shall be used based on experience and information about similar systems. Any assumptions made shall be technically justified and documented by the Integrity Engineer. The Regional Corrosion Control Team Lead or Engineer shall approve the assumptions made.

5.2.3.1 Assumptions shall not be made for the following data elements:

- Pipe diameter.
- Pipe wall thickness.
- CP system type.
- Coating type.

5.2.4 The Integrity Engineer shall be responsible for completing the data collection. If Required Data elements are found to be missing or incomplete, a plan shall be implemented to collect the missing data. All data collected shall be recorded in the OPS-STD-0028-FOR-02 form.

5.2.5 Prior integrity assessments of the Pipeline Segment may be used as a resource for Pre-Assessment data; however, they should not be used as a substitute for the data collection process outlined in this plan.

5.3 Identification of SCCDA Regions

5.3.1 The Pipeline Segment shall be divided into SCCDA Regions. An SCCDA Region is a portion of a Pipeline Segment that has similar physical characteristics, loading, Cathodic Protection histories, and expected future conditions relative to the potential for SCC. These regions may contain non-continuous pipeline sections.

5.3.2 The Integrity Engineer shall establish the SCCDA Regions in consultation with the Regional Corrosion Control Team Lead or Engineer. The L0-10.026-FOR03 form shall be used during the process of establishing pipeline regions. The primary decision process for establishing pipeline regions within a segment shall consider:

- Availability of prior operating history and a determination that future operation is expected to be reasonably similar.
- A determination that factors that influence SCC susceptibility are known and similar, such that zones with similar characteristics can be grouped into SCCDA Regions.
- Pressure loading along the pipe segment, including cyclic loading characteristics, such that zones with similar loading can be identified.
- A determination that the historic and current performance of the Cathodic Protection system is known and consistent.

5.3.3 When identifying SCCDA Regions, the Integrity Engineer shall consider the data collected and all conditions that significantly affect (or drive) SCC. For example, a separate SCCDA Region shall be required when the pipe wall thickness changes or when coating type changes.

5.3.4 The following provides a description of various factors that can affect SCCDA Region selection:

Age – The year of installation impacts the time over which coating degradation may have occurred and the period over which Cathodic Protection performance may have changed. The age of the pipe helps indicate the probable steel making process and pipe manufacturing technology, which can affect susceptibility. In addition, older pipe materials typically have lower toughness levels, which reduces critical Defect size and remaining life predictions.

Pipe Related Characteristics – The grade, diameter, and wall thickness of the pipe affect the pressure loading and susceptibility to SCC. Also, some pre-1970 ERW or flash welded pipe seams may be more susceptible to SCC; pipe manufacturing type is an essential parameter in selecting SCCDA Regions. Knowing the specifications and grade to which the pipe was made affects critical Defect sizes and remaining life predictions.

Pipeline Coating Types – Coating type may influence the time at which SCC initiates and estimates of crack growth rates based on measured crack depths. Certain types of coating make the pipe more susceptible to SCC, especially tape and asphaltic coatings. Coatings type should be identified/known for girth welds, recoats, and field repairs.

Operating Stress and Stress Risers – Stress plays a major role in defining susceptibility to SCC. Nominal hoop stress plus pipe grade define the percent SMYS to which the line operates, which in turn affects susceptibility. The presence of dents, mechanical damage, bends, casings, weights, etc. can introduce local stresses, thereby increasing susceptibility. Cyclic stress affects the crack growth rate.

History of Pipeline Movement – Pipeline movement, including operations such as rerouting or lowering a line, affect local stresses and susceptibility.

Construction Characteristics – Significant differences in construction practices may require separate SCCDA Regions. Locations of valves, clamps, supports, taps, mechanical couplings, etc., can be used to help determine changes in Cathodic Protection that should be considered separately. Locations where Cathodic Protection levels are significantly affected by external sources (e.g., high-voltage electric transmission lines) should be treated as separate SCCDA Regions.

Soil and Environment – Soil-related and environmental factors should be reviewed along the entire length of the pipeline to determine any changes that necessitate separate regions. Certain combinations of soil type, topography, and drainage are thought to be more conducive to SCC. They also influence the formation and susceptibility to External Corrosion.

Locations with Weights and Anchors – May affect local susceptibility.

Casing Locations – Casings are potential locations of Shielding and coating damage.

Cathodic Protection Data – The likelihood and extent of cracking is strongly affected by the historic and current Cathodic Protection levels at to the pipe. Both high pH SCC and near neutral pH SCC require low (more positive than -850 mV) polarized potentials. The length of time without Cathodic Protection is also important.

Leak and Repair History – Information about pipe replacements or repairs may indicate where problems may have occurred in the past. Replaced and recoated pipe will generally be less susceptible to cracking, assuming the replacement coating is of high quality.

5.3.5 SCCDA Regions may need to be modified throughout the SCCDA process. This could be due to unexpected conditions. Any change shall be documented and attached to the L0-10.026-FOR03 form by the Integrity Engineer. The Integrity Engineer shall also be responsible for including any changes to SCCDA Regions in the Feedback and Continuous Improvement section of the Post-Assessment step.

5.4 Selection of Indirect Inspection Tools

5.4.1 The Integrity Engineer shall select and document which Indirect Inspection tools shall be used for each SCCDA Region along the Pipeline Segment.

5.4.2 At least two complementary (2) Indirect Inspection tools capable of detecting Corrosion Activity and coating conditions reliably under the specific pipeline conditions shall be performed over the entire length of each SCCDA Region. Tools selected for each SCCDA Region shall complement one another. Specifically, the tools should be selected such that the strengths of one tool compensate for the limitations of another. This program recognizes the six (6) Indirect Inspection tools listed in Table 3.

5.4.2.1 Recommended guidance for performing CIS testing can be located in TSCP-006 Cathodic Protection Survey Procedure 6 "Close Interval Survey (CIS) Testing".

5.4.2.2 Recommended guidance for DCVG testing can be located in TSCP-006 Cathodic Protection Survey Procedure 7 "Direct Current Voltage Gradient (DCVG) Testing".

5.4.2.3 Recommended guidance for ACCA and ACVG testing can be located in TSCP-006 Cathodic Protection Survey Procedure 8 "Alternating Current-Current Attenuation (ACCA) and Alternating Current Voltage Gradient (ACVG) Testing".

5.4.2.4 Recommended guidance for Pearson Survey testing can be located in TSCP-006 Cathodic Protection Survey Procedure 27 "Pearson Survey Testing".

5.4.2.5 Recommended guidance for soil resistivity testing can be located in TSCP-006 Cathodic Protection Survey Procedure 19 "Soil Resistivity Testing".

5.4.3 The use of a tool not listed in Table 3 shall be approved by the Regional Corrosion Control Team Lead or Engineer. The justification and verification of the tool shall be documented by the Integrity Engineer.

Table 3 Recognized Indirect Inspection Tools

Indirect Inspection Tool	Measurement Attributes	Typical Uses	Less Suitable For	Complementary Tools
Close Interval Survey (CIS)	Measures structure-to-Electrolyte potentials along the pipeline at 2.5 to 10-foot intervals.	Generally used to assess the performance of CP systems and generally estimate the location of coating Holidays. Can also detect interference, shorted casings, electrical or geological Shielding, contact with other metallic structures as well as Defective electrical isolation joints.	Pipelines that are below paved areas require holes to be drilled to the soil. Is not effective in detecting Disbonded Coatings that are Shielding the pipe from Cathodic Protection current.	DCVG, ACVG, Pearson Survey, ACCA
Current Attenuation Survey (ACCA)	Measures the electro-magnetic field attenuation emanating from the pipe induced with an AC signal. Qualitatively ranks coating quality and highlights areas with the largest Holidays.	Can be used for pipelines under pavement and CP systems that are difficult to isolate.	Not indicative of structure-to-Electrolyte potential or effectiveness of CP. Is ineffective under HV transmission lines. Is not effective in detecting Disbonded Coatings that are Shielding the pipe from Cathodic Protection current.	CIS
DCVG/ACVG/ Pearson Survey	Measures voltage gradients resulting from current pickup and discharge points at Holidays. Capable of precisely locating Holidays on the pipeline.	Generally used to precisely locate large and small coatings Holidays on buried pipelines.	Pipelines that are below paved areas require holes to be drilled to the soil. Is not effective in detecting Disbonded Coatings that are Shielding the pipe from Cathodic Protection current.	CIS
Soil Resistivity	Measures the resistivity of soil at different layers.	Generally used to characterize the resistance and corrosivity of the soil.	Not indicative of the effectiveness of Cathodic Protection or in determining the effectiveness of coating systems.	CIS, DCVG, Pearson Survey, ACVG, ACCA

5.4.4 The Integrity Engineer shall determine the required number of tools to reliably detect Corrosion Activity for each SCCDA Region. The same survey tools do not need to be used over the entire Pipeline Segment.

5.4.5 Table 4 provides additional guidance for selecting Indirect Inspection tools and specifically addresses conditions under which some Indirect Inspections tools may not be practical or reliable.

5.4.6 OPS-STD-0027-FOR-03 shall be used to document the Indirect Inspection tools selected. The Integrity Engineer shall complete this form and document supporting justification. This form and supporting technical justification shall be verified and approved by the Regional Corrosion Control Team Lead or Engineer.

Table 4 Indirect Inspection Tool Selection

Conditions	Close Interval Survey (CIS)	Voltage Gradient Survey (DCVG and ACVG)	Pearson Survey	Current Attenuation Survey (ACCA)
Coating Holidays	2	1,2	2	1,2
Anodic zones on bare pipe	2	3	3	3
Near river or water crossings	2	2	2	2
Under frozen ground	3	3	3	1,2
Stray currents	2	1,2	2	1,2
Shielded Corrosion Activity	3	3	3	3
Adjacent metallic structures	2	1,2	3	1,2
Near parallel pipelines	2	1,2	3	1,2
Under high-voltage alternating current overhead electric transmission lines	2	1,2	2	2
Under paved roads	3	3	3	1,2
Crossing other pipelines	2	1,2	2	1,2
Cased piping	3	3	3	3
At very deep depth of cover	3	3	3	3
Wetlands	2	1,2	2	1,2
Rock terrain/rock ledges rock backfill	3	3	3	2

Key:

1 - Applicable: Small coating Holidays (isolated and typically less than 600 mm^2 (1 in^2) and conditions that do not cause fluctuations in CP potentials under normal operating conditions).

2 - Applicable: Large coating Holidays (isolated and continuous) or conditions that cause fluctuations in CP potentials under normal operating conditions.

3 - Applicable when it can be demonstrated, through Sound Engineering Practice and thorough analysis of the inspection location, that chosen methodology produces accurate comprehensive results that result in a valid integrity assessment of the Pipeline Segment.

5.4.7 Cased piping creates limitations for Indirect Inspection tools and the ability of those tools to detect Corrosion Activity. As such, other considerations are made for Indirect Inspection tools that shall be used for cased piping.

Additional considerations should reflect the level of performance of each tool, and the nature of the data or information that can reasonably be expected from the tools. The main limitation of most Indirect Inspection tools is that they can only reliably identify if there is a pipe-to-casing electrical continuity of some kind, but not differentiate between continuities.

5.5 Developing an Indirect Inspection Plan

5.5.1 An Indirect Inspection Plan shall be developed prior to commencing the Indirect Inspections. The plan addresses project logistics, survey procedures and specifications, safety procedures, personnel requirements, and data analysis requirements. The plan shall include, but is not limited to, the following:

- Pipeline Segment maps with boundaries and pertinent information clearly identified and labeled by location (e.g. bonds, casings, roads, etc.).
- Clearly defined SCCDA Region(s) along the entire Pipeline Segment to be assessed.
- Identified Indirect Inspection surveys to be performed within each SCCDA Region and the sequence in which the surveys must be conducted.
- Flagging and stationing methodology to be used during the surveys
- The training, experience or OQ requirements for the individuals conducting the Indirect Inspection surveys.
- The procedures for performing each survey including, but not limited to, the limitations and sensitivities of the technique and the spacing required between readings.
- Requirements on overlapping surveys, if applicable.
- Weather or seasonal considerations (frozen ground)

5.5.2 The plan shall be documented by the Integrity Engineer, and submitted to the Regional Corrosion Control Team Lead. The Regional Corrosion Control Team Lead is responsible for managing the plan.

6.0 INDIRECT INSPECTION

6.1 Purpose

6.1.1 The purpose of the Indirect Inspection step is cover aboveground inspections (Table 3) to identify and define the severity of coating Faults, other anomalies, and areas where Corrosion Activity may have or may be occurring in the areas under investigation. Two or more complementary Indirect Inspection tools shall be used over the entire Pipeline Segment under investigation to provide improved detection accuracy under the wide variety of conditions that may be encountered along a pipeline right-of-way. The combination of Indirect Inspections may vary based on the characteristics of different regions that may exist along the Pipeline Segment being assessed.

6.1.2 Aboveground survey data should be analyzed differently when selecting sites for ECDA digs versus SCCDA digs. For example, high pH SCC has been observed on pipe that appears to be adequately protected in a Close-Interval Survey but where the actual potential at the pipe surface is less negative because of Shielding by Disbonded Coatings. For near neutral pH SCC, the absence of Cathodic Protection, either due to Shielding or inadequate Cathodic

Protection, can allow SCC to proceed. Since SCC requires coating Faults, indications of coating Holidays in voltage gradient surveys could help identify problem areas.

6.2 Conducting Indirect Inspections

6.2.1 After the Indirect Inspection Plan has been approved by the Regional Corrosion Control Team Lead or Engineer, the aboveground surveys shall be conducted in accordance with the MPLX L&S - Southwest Gathering Corrosion Control Program, MPLX L&S – Southwest Gathering Cathodic Protection Survey Procedures, and this standard. The surveys shall be completed by a survey crew and each survey crew shall include at least one Corrosion Technician/Specialist/Engineer.

6.2.2 The Indirect Inspections shall be conducted and completed as close together in time as practical.

6.2.3 The pipeline shall be clearly marked in the field. Photographs of the survey route and markings may be used to provide documentation of the route, markings, weather, and Terrain Conditions during the surveys.

6.2.4 During the Indirect Inspections, accurate stationing for readings shall be obtained. Accuracy shall be verified by the Integrity Engineer by comparing measured stationing to the alignment sheet for the Pipeline Segment. The difference between the measured stationing and the stationing of locations on the alignment sheet shall be less than 2%. The Integrity Engineer shall be responsible for resolving any discrepancies. The Pipeline Segment shall be located with reference to clearly described aboveground locations. GPS measurements shall be collected at every reading and at every pipeline feature or appurtenance along the right-of-way. This includes recording the position of the following:

- Each pipeline marker.
- Cathodic protection test stations.
- The edges and center of:
    - Road crossings
    - Waterways.
    - Ditches.
- Fences.
- Overhead power lines.
- Foreign line and utility crossings.
- Any sections of exposed pipe.
- Any locations with evidence of soil erosion along the right-of-way.

6.2.5 The Integrity Engineer shall witness a portion, or all, of the Indirect Inspections to verify that the Indirect Inspection personnel are following the ECDA Indirect Inspection Plan. Any such field audits and their findings shall be documented by the Integrity Engineer and given to the Indirect Inspection personnel. The audit findings shall also be reviewed by the Regional Corrosion Control Team Lead or Engineer.

6.3 Data Alignment and Comparison

6.3.1 The Integrity Engineer shall overlay the data sets from the Indirect Inspections. The results of data alignment shall be documented as part of the final report. The data shall be aligned such that individual indications on coated lines can be identified, or such that possible anodic regions on bare lines can be identified. The results of the surveys shall be compared to the Pre-Assessment data to confirm the feasibility of SCCDA and confirm SCCDA Regions were appropriately defined. If discrepancies exist regarding the ability of tools to accurately inspect the Pipeline Segment or if data do not support the defined SCCDA Region, these discrepancies shall be resolved by the Integrity Engineer prior to proceeding to the next activity in the Indirect Inspection step. Any discrepancy, and associated resolution, shall be documented and attached to OPS-STD-0028-FOR-01.

6.3.2 The impact of spatial errors from various techniques shall be considered when aligning data. Any suspected spatial errors shall be investigated prior to indication classification and prioritization.

6.4 Identifications of Indications

6.4.1 The Integrity Engineer shall be responsible for identifying SCCDA Indications. Analysis software may also be used, if approved by Regional Corrosion Control Team Lead or Engineer, based on comparisons between surveys. The criteria for determining SCCDA Indications may be determined on a per project basis as results may vary based local conditions and unique project factors. At a minimum, criteria for identifying SCCDA Indications shall consider the following:

- The known sensitivities of the survey equipment.
- The procedures used during the survey.
- The approach used for decreasing the physical spacing between measurements.

6.4.2 The criteria for identifying SCCDA Indications shall be based on Sound Engineering Practice and conform to generally accepted industry practices. Typically, potential SCCDA Indications are changes in measured values that exceed normal variations (e.g. "noise") and cannot be explained by changes in conditions along the SCCDA Region. For example, a signal strength change that is greater than five times the instrument resolution might be considered an indication. When a clear determination cannot be made regarding indications, assumptions shall be conservative such that a potential indication is considered to be an indication unless additional investigation proves otherwise. Additionally, any changes to the criteria during the selection process shall be documented with justification.

6.4.3 The final criteria for selecting SCCDA Indications shall be documented by the Integrity Engineer. The criteria shall then be verified and approved by the Regional Corrosion Control Team Lead or Engineer. These criteria shall to be attached to OPS-STD-0028-FOR-01. Selection criteria need not be the same for each SCCDA Region, however if criteria are different, the different criteria shall be documented with justification for the differences.

6.4.4 SCCDA Indications shall be selected by evaluating superimposed data from different SCCDA tools, local environmental conditions, and physical pipeline features. When potential indications from multiple tools (and other related information) coincide, the location will be considered an SCCDA Indication. Indications shall be chosen using engineering analysis and judgment of signal relevance (e.g. CIS dips, alignment with DCVG, etc.).

6.4.5 Locations where the Indirect Inspection survey results are not consistent shall be identified. Locations where one survey identifies an indication, but others do not, shall be evaluated to determine if the discrepancies can be explained by inherent tool capabilities or specific/localized pipeline features or conditions. If discrepancies cannot be explained, additional surveys or preliminary Direct Examinations shall be considered as follows:

- Use additional complementary survey tools.
- Use an approach to decrease the physical spacing of Indirect Inspection tool readings is followed when the presence of an indication is suspected.
- Perform preliminary Direct Examinations to resolve discrepancies, provided the examinations identify a localized and isolated cause of the discrepancy.
- If the above do not resolve the discrepancies, SCCDA feasibility may be reassessed. In addition, additional Direct Examinations may be considered, or the location may be prioritized as for Immediate action required on Direct Examination step.

6.4.6 While SCCDA is suited for detecting Stress Corrosion Cracking, it is capable of detecting other threats to the pipeline. Data that have been integrated from other sources shall be considered when identifying indications. Other sources include operational or incident data, encroachment records, "one call" records, or data showing close proximity of foreign structures. If an indication from the SCCDA process detects an Anomaly where another integrity threat may exist, for example a location where third-party damage may have occurred, these locations may be considered for Direct Examination.

6.5 Classification of Indication Severity

6.5.1 The Integrity Engineer shall define and apply severity classification criteria for identified SCCDA Indications based on the likelihood of Corrosion Activity. The Integrity Engineer shall be responsible for ensuring that the criteria are documented. The final criteria shall be attached to OPS-STD-0028-FOR-01. The final criteria shall also be approved by the Regional Corrosion Control Team Lead or Engineer. The criteria shall take into account the specific conditions along the pipeline during the survey. The following classifications shall be used at a minimum:

- **Severe -** Indications that are considered as having the highest likelihood of Corrosion Activity.
- **Moderate -** Indications that are considered as having possible Corrosion Activity.
- **Minor -** Indications that are considered Inactive or have the lowest likelihood of Corrosion Activity.

6.5.2 More detailed criteria may be used if necessary. Table 5 provides general guidelines of indication classification. A weighted algorithm shall be used to determine the indication classification. The algorithm applies a numerical value for each survey result and then factors are applied to these numerical values to provide more significance to the results deemed most likely to be associated with Corrosion Activity.

Table 5 General Guidelines for Indication Classifications

Tool/Environment	Minor	Moderate	Severe
CIS, aerated, moist soil	Small dips with on and off potentials above CP criteria	Medium dips or off potentials below CP criteria	Large dips or on and off potentials below CP criteria
DCVG survey, similar conditions	Low voltage drop; cathodic conditions at indication when CP is on and off	Medium voltage drop and/or neutral conditions at indication when CP is off	High voltage drop and/or anodic conditions when CP is on or off
ACVG or Pearson survey, similar conditions	Low voltage drop	Medium voltage drop	High voltage drop
Soil Resistivity	Mildly Corrosive Soil	Corrosive Soil	Very Corrosive Soil
ACCA Survey	Small increase in attenuation per unit length	Moderate increase in attenuation per unit length	Large increase in attenuation per unit length

6.5.3 Table 6 provides an example methodology for determining a numerical value score for each survey result. The determination criteria provided in Table 6 may be used as a default, altered by the Integrity Engineer, if necessary, to meet the needs of each individual project. Any alteration to the numerical weighting shall be approved by the Regional Corrosion Control Team Lead or Engineer. This process also applies for cased piping; however, a different algorithm should be utilized based on a numerical score assigned to each survey result used to analyze the cased piping. The numerical weight applied to each variable is based on the confidence of the data collected and the increased likelihood of Corrosion based on the survey finding. A higher calculated weighting factor (W), see Equation 1, is a result of the severity of the individual indications based on the accuracy of the indirect tool. As such, more Severe Indications coupled with a less accurate survey technique result in a more conservative and thus higher priority ranking for Direct Examination classifications.

Table 6 Criteria for Classifying Indications with Numerical Rankings

Variable	Tool/Environment	Minor	Moderate	Severe
		0.5 Score	1.5 Score	2.5 Score
A1	CIS, aerated, moist soil - CP Meets Protection Criteria	Off doesn't meet -0.85 V criterion but meets 100 mV criterion	On meets -0.85 V criterion, Off doesn't meet -0.85 V criterion or100 mV criterion	On & Off doesn't meet -0.85 V criterion or 100 mV criterion, or reverse potential shift
B1	DCVG survey, similar conditions	<15% IR	16 to 35 % IR	> 35 % IR
B2	CIS, aerated, moist soil – Potential Dips	<50 mV dip	50 – 100 mV dip or < Criteria	>100 mV dip or < Criteria
B3	Wenner 4-pin	> 10,000 Ohm-cm	1000-10000 Ohm-cm	< 1000 Ohm-cm
B4	ACVG or Pearson survey, similar conditions	Low voltage drop	Medium voltage drop	High voltage drop
B5	ACCA survey	Low signal loss	Medium signal loss	Large signal loss
B6	Carrier Structure-to-Electrolyte and Casing-to-Electrolyte Potential Test	Potential difference greater than 100 mV	Potential difference between 100 mV and 5 mV	Potential difference smaller than 5 mV

6.5.4 An example weighting algorithm for combining indirect survey results and determining the severity classification is as follows:

$$W = 3A_1 + 2B_{(1 \text{ or } 4 \text{ or } 5)} + B_{(2 \text{ or } 3 \text{ or } 6)} \quad (1)$$

Where:

A1 = The numerical score of the CIS survey results (CP Meets Protection Criteria) where anomalies are identified.

B1 = The numerical score of the DCVG survey results where anomalies are identified.

B4 = The numerical score of the ACVG or Pearson survey results where anomalies are identified.

B5 = The numerical score of the current attenuation survey results where anomalies are identified.

B2 = The numerical score of the CIS survey results (Potential Dips) where anomalies are identified.

B3 = The numerical score of the Soil Resistivity results where potentially corrosive environments are identified.

B6 = The numerical score of the Carrier Structure-to-Electrolyte and Casing-to-Electrolyte Potential Test.

6.5.5 Final classification of the SCCDA Indications based on the weighted algorithm could then be determined based on the ranges provided in Table 7.

Table 7 Indications Severity Classification Range

Indication Severity Classification	Weighting Algorithm (W) Range
Severe	$12 \leq W \leq 15$
Moderate	$6 \leq W < 12$
Minor	$0.5 \leq W < 6$

6.5.6 The classification ranges presented in Table 7 may be used as a default; however, the Integrity Engineer may consider the use of a different weighting algorithm based on the specific pipeline conditions. The Regional Corrosion Control Team Lead or Engineer shall approve the weighted algorithm used. The indication severity classification algorithm shall be documented.

6.5.7 The indication severity for identified indications shall be documented in OPS-STD-0027-FOR-05 by the Integrity Engineer. This information shall be approved by the Regional Corrosion Control Team Lead or Engineer.

6.6 Site Selection

6.6.1 The Integrity Engineer, in consultation with the Regional Corrosion Control Team Lead or Engineer, is responsible for selecting SCCDA Direct Examination sites. SCCDA Direct Examination sites are based on an analysis of the coating, stresses, soil, drainage, topography, and Cathodic Protection performance (current and historical) along the line. As part of this data integration, a loading analysis shall be conducted. The loading analysis should characterize the stresses along the pipeline, including cyclic and secondary stresses, and identify locations where stresses are high or otherwise elevated.

6.6.2 The Integrity Engineer shall select more Direct Examination sites than required to provide extras in the event a site is inaccessible or not otherwise suitable for excavation.

6.6.3 Table 8 summarizes factors that shall be considered in selecting sites. For additional information, see the SCC Management Program information in LO-18.001-STD.

Table 8 Summary of Excavation Selection Criteria for SCCDA

Factor	Consider
SCC has been previously found on or near the line	Similar locations
Coating type	• Coal Tar: High pH SCC • Polyethylene tape or Asphalt: Near neutral pH SCC
Coating condition	Areas of disbonded and/or damaged coating
Cathodic protection	Areas that have exhibited dips in Cathodic Protection levels and in areas that are difficult to protect (e.g., near ends of casings)
Operating stress (high pH SCC)	Highest stress areas, locations over 60% SMYS
Locally elevated stresses (near neutral pH SCC)	Near the long seam, dents, near bends, including overbends and sagbends
Age	Older segments

Temperature (high pH SCC)	Locations with historic or current operating temperatures over 100 degrees Fahrenheit
Other Factors	See the SCC Management Program information in LO-18.001-STD.

7.0 DIRECT EXAMINATION

7.1 Purpose

7.1.1 The purpose of the Direct Examination step is to look for SCC and assess whether conditions suitable for SCC to develop are present. Conditions suitable for SCC include large areas of disbonded or damaged coating, signs of ineffective Cathodic Protection, and Electrolyte pH in the range needed for cracking (10 to 12 for high pH SCC and 5 to 7 for near neutral pH SCC).

7.1.2 If SCC is detected, the presence, extent, type, and severity of the SCC shall be assessed. Depending on the severity of the SCC found, additional Direct Examinations and/or other integrity assessments may be required. All pipelines on which SCC is found shall be managed in accordance with the SCC Management Program information in LO-18.001-STD.

7.1.3 Sites selected for Direct Examination require exposure of the pipeline and coating surface so that a detailed inspection and examination can be performed. The Direct Examination step includes the following activities:

- Site prioritization.
- Minimum number of excavations.
- Minimum excavation lengths.
- Scheduling of excavations.
- Excavation and initial data collection.
- Coating damage and external metal loss data collection.
- SCC-related data collection.
- Cracking severity evaluation.

7.2 Site Prioritization

7.2.1 The Integrity Engineer, in consultation with the Regional Corrosion Control Team Lead or Engineer, is responsible for prioritizing sites for excavation and inspection. In general, prioritization should be in order of perceived susceptibility to SCC. The SCC Management Program information in LO-18.001-STD contains additional information on susceptibility.

7.2.2 If previous excavations have been performed due to any reason for Direct Examination, the results of the Direct Examinations of those excavations shall be taken into account in prioritizing sites. The year-round conditions around a pipeline shall also be considered in setting the excavation priority. This includes physical characteristics of each SCCDA Region. In addition, consideration shall be given to prior Cathodic Protection history, stresses on the pipe, and the pipe's strength and ability to withstand cracking without failure.

7.3 Minimum Number of Excavations

7.3.1 The Integrity Engineer shall be responsible for selecting the number of sites for Direct Examination. The minimum number of Direct Examinations shall be determined according to the SCC Management Program information in LO-18.001-STD and the guidelines given below. Additional sites may be required if SCC or conditions suitable for SCC are found.

7.3.2 The minimum number of Direct Examinations is no less than:

- Two excavations in the SCCDA Region deemed most susceptible and
- One excavation in the next most susceptible SCCDA Region.

7.3.3 Note that when linear indications or conditions suitable for SCC are found at an excavation site, additional digs or mitigation shall be required.

7.3.4 The Integrity Engineer, in consultation with the Regional Corrosion Control Team Lead or Engineer, shall determine the number of additional digs and/or mitigation.

7.3.5 Previous excavations may be substituted for SCCDA digs if

- All necessary data has been collected,
- The location has a susceptibility at least as high as the location for which it is being substituted, and
- The excavation was performed within the previous 12 months.

7.3.6 Previous excavations may be substituted for no more than half of the required minimum number of digs.

7.4 Minimum Excavation Lengths

7.4.1 The Integrity Engineer shall be responsible for defining the length of each SCC investigative excavation based on information from Close-Interval Surveys, terrain condition, etc. The following guidelines apply:

- Except when an excavation site is selected to investigate locally elevated stresses (e.g., near welds, dents, bends, etc.), consideration shall be given to excavating/inspecting the entire pipe joint and 10 feet of the upstream and downstream pipe joints.
- When an excavation site is selected to investigate near welds and dents, consideration shall be given to excavating/inspecting at least two feet on either side of the weld or dent.
- When an excavation site is selected to investigate near bends or other features, consideration shall be given to excavating/inspecting the entire pipe joint.

7.5 Scheduling

7.5.1 The Integrity Engineer shall be responsible for establishing a schedule for conducting Direct Examinations at all of the selected based on the excavation priorities and the number of excavations to be conducted. The excavation schedule shall be developed within 30 days after a determination has been made that a line segment is susceptible to SCC. In determining a schedule, the Integrity Engineer shall consider issues such as:

- Permitting.
- Right-of-way access.
- Time needed to ensure that adequate inspection equipment is available.

- Time needed to ensure that appropriate crews are available.
- The schedule may recognize that, for example, permitting in a public area has been applied for but not approved by the correspondent authority.

7.6 Excavations and Initial Data Collection

7.6.1 A qualified representative of MPLX shall be present during all excavations. Qualified representatives include the Integrity Engineer, , Regional Corrosion Control Team Lead or Engineer, or an individual deemed acceptable by approved individuals. The representative shall be responsible for ensuring all work is performed as per MPLX procedures during excavations and data collection. Care shall be taken during the excavation to avoid damaging the pipeline coating and removing any Corrosion or protective products that are critical to the overall analysis.

7.6.2 The Integrity Engineer shall be responsible for ensuring that appropriate NDT techniques are applied at excavation sites. Consideration should be given to inspecting the entire exposed area. At a minimum, wet MPI with a contrast coating shall be performed at the following locations which are indicative of coating breakdown:

- Corrosion and/or cathodic deposits are present.
- Coating is disbonded or damaged.
- Moisture (Electrolyte) is present.
- Within 6 inches of all welds and within 2 feet of all stress risers.

7.6.3 Dig photographs (with an appropriate ruler or scale) at all SCC excavation sites shall be documented. Each detected Cluster shall be given a unique identifier and the location of the center of the Colony shall be identified relative to a reference point, such as a weld and a clock position. Following completion of the wet MPI, each detected crack Cluster shall be photo documented and evaluated as described below.

7.6.4 An Inspector (per Table 2) is responsible for data collection during the Direct Examinations. Data collected during each Direct Examination shall be documented using the OPS-STD-0027-FOR-06 form. Data collected shall be verified and approved by the Integrity Engineer. One form shall be completed per Direct Examination. Relevant data listed on the form shall be collected.

7.6.5 The Integrity Engineer shall verify that the number of digs performed is in accordance with the required number of Direct Examinations. The Integrity Engineer shall also record the final date of completion of the Direct Examinations.

7.7 Coating Damage and External Metal Loss Data Collection

7.7.1 Examination of the coating surface shall be performed and recorded in the OPS-STD-0027-FOR-06 form. The following guidelines shall be adhered to during coating and pipe surface examination:

- If products are present on the pipe surface, the products shall be analyzed with field chemical testing for pH and specific ions (iron, carbonates, and sulfides).
- The coating condition shall be recorded. The coating condition evaluation includes such observations as blistering and lack of adhesion. The area of any pipeline with no coating, loosely adhered coating and Disbonded

Coating shall be estimated. Viable qualitative adhesion tests shall be performed. The coating shall also be inspected for the presence of Holidays and coating thickness. All coating conditions, observations, and measurements shall be documented.

- A coating sample shall be obtained carefully using a clean knife to expose the steel beneath the coating, if possible. Coating samples shall be placed in sealed plastic bags identified by dig location, sample location, date, and person gathering the samples. No coating samples will be needed if the coating is intact and well adhered to the pipe surface.
- If liquid or moisture is present on the pipe surface, the pH of the liquid shall be measured. However, in case of no liquid or moisture, the addition of deionized water shall be used to measure the pH on the pipe surface.
- In case of any coating damage or coating Holiday, the coating shall be removed in order to perform pipe wall examination. Correlation of any possible relationship between coating and pipeline surface damages shall be documented.
- Structure-to-Electrolyte polarized potentials shall be taken at both the upstream and downstream ends of the excavation.
- Pipe wall thickness measurements, at all four quadrants (3, 6, 9 and 12 o'clock) and at upstream and downstream ends, shall be measured to obtain reliable and actual wall thickness.
    - o If the ends are underneath well adhered coating, wall thickness readings shall only be made at the indication location.
- The presence of any external metal loss and mechanical damage shall be documented. The external metal loss will be characterized as general, localized, or pitting. Data collection for external metal loss shall be in accordance with LO-18.001-STD. At a minimum, the length, width, and depth of the external metal loss, as defined in LO-18.001-STD, shall be recorded.

7.7.2 Photographs of examination findings shall be collected. This includes finding the pipe exposed in good condition and/or free of anomalies.

7.8 SCC-Related Data Collection

7.8.1 Per NACE SP0204, the types of SCCDA data to be considered for collection are included in Table 3. All items listed as 'Required Element for SCCDA' shall be collected. Additional data collection for SCCDA is described in the SCC Management Program information in LO-18.001-STD.

Table 9 Data Collected at a Dig Site in an SCCDA Program and Relative Importance

Data Element	When Collected	Use and Interpretation of Results	Ranking*
Structure-to-Electrolyte potential (IR-free)	Prior to coating removal.	Useful for comparison with ground surface structure-to-Electrolyte potential (IR-free) measurements.	D

Data Element	When Collected	Use and Interpretation of Results	Ranking*
Soil resistivity	Prior to coating removal.	Related to soil corrosiveness and soluble cation concentration of soil. Useful for comparison with results of soil and groundwater analyses.	C
Soil samples	Prior to coating removal.	Useful in confirming Terrain Conditions. Soil analysis results can be trended in predictive model.	B
Groundwater samples	Prior to coating removal.	Chemistry results can be trended in predictive model.	B
Coating system	Prior to coating removal.	Required element. Used for field site verification and in predictive model development.	A
Coating condition	Prior to coating removal.	Can be related to extent of SCC found.	C
Measurement of coating disbondment	Prior to coating removal.	Locations of disbondment can be related to presence of cracking and other measured data.	C
Electrolyte	Prior to coating removal.	Useful in establishing type of cracking. Can be related to groundwater chemistry.	C
Photograph of dig site	Prior to coating removal.	Useful in confirming Terrain Conditions, coating system, and coating condition.	D
Data for other integrity analyses	Before and after coating removal.	Data for other analyses (e.g., dent measurements) may be related to occurrence of SCC.	C, D
Deposit description and photograph	After coating removal.	Useful in establishing type of cracking.	C
Deposit analysis	After coating removal.	Useful in establishing type of cracking.	C
Identification and measurement of Corrosion Defects	After coating removal.	Used for integrity assessment of Corrosion Defects. Also used in establishing type of SCC, if present.	A, D
Photograph of Corrosion Defects	After coating removal.	Used in integrity assessments.	D
Identify weld seam type	After coating removal.	Required element. Used in field site verification.	A
MPI	After coating removal.	Required element for SCCDA. Establishes whether SCC is present.	A
Location and size of each Cluster	After coating removal.	Required element for SCCDA. Used to establish correlation of location with other parameters measured.	A
Crack length and depth measurements	After coating removal.	Required element for SCCDA. Used to establish significance of cracking	A

Data Element	When Collected	Use and Interpretation of Results	Ranking*
		and determine whether there is an immediate integrity concern.	
In situ metallography	After coating removal.	Used to establish type of SCC.	B
Photograph Clusters	After coating removal.	Required element for SCCDA. Used to confirm crack measurements.	A
Wall thickness measurements	After coating removal.	Required element. Used in integrity assessments and field site verification.	A, D
Measure pipe diameter	After coating removal.	Required element. Used in integrity assessments and field site verification.	A, D

* The relative importance of each data element (indicated in last column) is:

A: Required Element for SCCDA.

B: Optional (likely useful in SCCDA model development).

C: Optional (might be useful in SCCDA model development).

D: Useful background information or information used in other analyses.

7.9 Classification of Cracking

7.9.1 When linear indications are observed during the nondestructive inspections, the Integrity Engineer shall ensure that the following information is collected. Where practical, this information shall be collected for each individual crack Cluster. The Integrity Engineer shall consult with the Regional Corrosion Control Team Lead or Engineer before, during, and after data collection, as appropriate.

7.9.2 **Colony Dimensions -** The Colony length is the total length of the Colony in the axial direction. The Colony width is the total width of the Colony in the circumferential direction. The maximum length is the longest axial extent of the Colony, which might be different from the Colony length or width, depending on the Colony orientation. The maximum width is the dimension of the Colony perpendicular to the length direction. Figure 1 defines these dimensions.

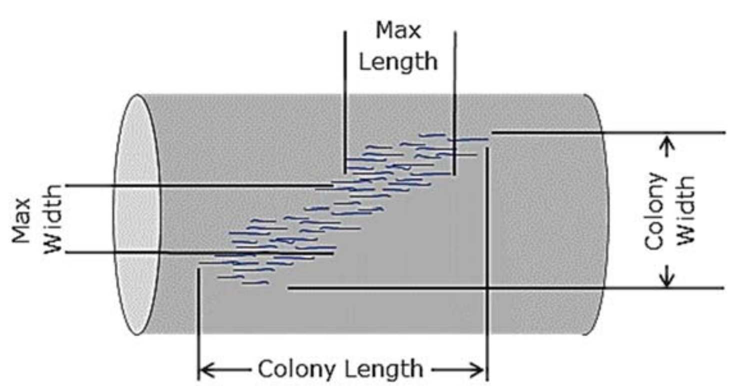


Figure 1 Colony Dimensions

7.9.3 **Interlinking of Cracks -** Cracks are defined to have interlinked if they physically have joined (coalesced) to form one longer crack (Figure 2).

7.9.4 **Interacting of Cracks -** Crack interaction depends on the circumferential and axial separation between individual cracks and is calculated as follows (Figure 3).

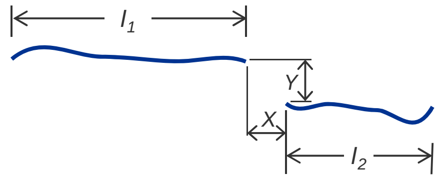


Figure 3 Interaction of Cracks

7.9.4.1 Two neighboring cracks are defined as interacting if their

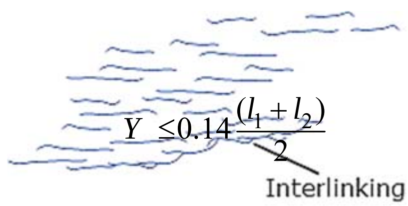


Figure 2 Interlinking of Cracks

circumferential spacing, Y, is less than 14% of the average crack length:

7.9.4.2 Two neighboring cracks are defined as interacting if their axial spacing is less than 25% of the average crack length, where l1 and l2 are the individual crack lengths:

$$X < 0.25 \frac{(l_1 + l_2)}{2}$$

7.9.5 **Maximum Interacting Crack Length -** Determine the maximum crack length, including interlinking and interacting cracks. The maximum interlinked crack length is the total length of the longest interacting and interlinking cracks, as defined above (Figure 4).

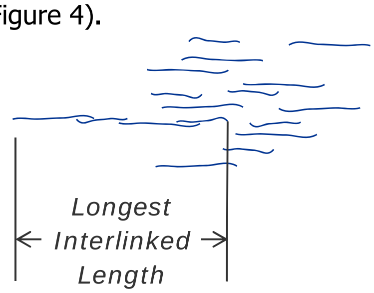


Figure 4 Maximum Interacting Crack Length

7.9.6 **Crack Depth -** Determine the maximum crack depth for evaluating crack severity and estimating the failure pressure. Since typically the longer cracks are also deeper, grinding should be performed on them first. If grinding is to be performed on a pressurized line, the initial wall thickness shall be determined by Ultrasonic Testing (UT), and a safe wall thickness shall be maintained at all times during grinding. Consideration shall be given to a pressure reduction before grinding.

7.9.7 **Crack Density -** Determine whether the cracking is dense (crack spacing less than 20% of the wall thickness) or sparse (crack spacing greater than or equal to 20% of the wall thickness).

7.9.8 **Location of SCC with Respect to Stress Risers -** Determine the position of the SCC in relationship to welds (e.g. at the weld toe, in base metal adjacent to the weld, in weld metal, or away from the weld). For dents, determine whether the cracking is at the shoulder, the maximum depth, or elsewhere. Also determine the crack location relative to any metal loss in or around the dent.

7.9.9 **Type of SCC -** If practical, document factors that could be related to the type of cracking. Typical factors are shown in Table 10.

7.9.9.1 In situ metallography may be performed to determine the crack path of the SCC (intergranular versus transgranular) and establish the type of SCC (High-pH SCC [intergranular] versus Near-Neutral-pH SCC [transgranular]). It can also help determine if the indication is a crack, sliver, lamination, etc. Removal of metal samples for destructive analysis may provide improved data on crack morphology, origin, and propagation.

Table 10 Factors for Identifying High pH SCC and Near neutral pH SCC

Near-neutral-pH SCC	High-pH SCC
Frequently associated with light surface Corrosion of the pipe.	Usually not associated with obvious External Corrosion.
Generally has poor Cathodic Protection	Generally well protected with Cathodic Protection
Tends to be wider than High-pH SCC; is sometimes visible to the naked eye.	Tends to be narrower than Near-Neutral-pH SCC; is rarely visible to the naked eye
Often associated with local stress risers, such as dents, welds, and transitions	Sometimes associated with welds and dents but can occur anywhere on the pipe
More common under tape and asphalt coatings	More common under coal tar coating
Electrolyte pH in the range of 5.5 to 7.5	Electrolyte pH in the range of 9 to 11 (or higher)
Can occur anywhere along the length of a Pipeline Segment	More commonly found within 20 miles of pump stations

7.9.10 **Cracking Severity Evaluation -** Where linear indications are found, the Integrity Engineer, in consultation with the Regional Corrosion Control Team Lead or Engineer, shall ensure that the severity of representative individual and interlinked cracks are determined using a suitable fracture mechanics analysis. The severity is defined by the SCC Management Program information in LO-18.001-STD.

8.0 POST-ASSESSMENT

8.1 Purpose

8.1.1 The purpose of the Post-Assessment is to determine if SCC mitigation is required, and assess the effectiveness of the SCCDA direct assessment process, and define re-assessment intervals. The Post-Assessment step includes the following activities:

- Determining mitigation.
- Assessment of SCCDA effectiveness.
- Definition of re-assessment intervals.
- Feedback for continuous improvement.

8.1.2 Upon completion of the project, the Integrity Engineer shall be responsible for compiling and submitting a final report to the Regional Corrosion Control Team Lead summarizing all phases of the project. The report shall also include all supporting documentation.

8.1.3 Upon receipt of the report, the Regional Corrosion Control Team Lead shall review the report and create an action plan for addressing any un-resolved issues. Any action plans are included in the final report. This action plan and the report shall be submitted to the Regional Corrosion Control Team Lead or Engineer for approval.

8.1.4 If SCC is found, the Integrity Engineer, in consultation with the Regional Corrosion Control Team Lead or Engineer, shall be responsible for identifying all other locations within the Pipeline Segment where similar conditions may exist. If similar conditions exist, these locations shall be evaluated.

8.2 Determining Mitigation

8.2.1 For SCCDA, guidance for mitigation on pipelines is provided in Part A3 of ASME B31.8S and in the SCC Management Program information in LO-18.001-STD. When applying B31.8S to liquids pipelines, the characteristics of the Pipeline Segment shall be considered. Additional guidance for pipelines subject to near neutral pH SCC is provided in the CEPA Stress Corrosion Cracking Recommended Practices. When applying guidance found in these documents to liquids pipelines, the potential for fatigue and or Corrosion fatigue shall be considered in order to establish appropriate intervals for inspection and mitigation activities.

8.2.2 The Integrity Engineer, in conjunction with the Regional Corrosion Control Team Lead or Engineer, is responsible for determining the need for mitigation and remedial action. Mitigation and/or remedial action is required if Category 1, 2, 3, or 4 SCC is found.

8.3 Definition of Re-Assessment Interval

8.3.1 The Regional Corrosion Control Team Lead or Engineer, in consultation with the Regional Corrosion Control Team Lead or Engineer, shall establish the re-assessment intervals based on information such as:

- The extent and severity of the SCC detected during the original investigation.
- The estimated rate of propagation of the crack Clusters and remaining life of the pipe containing the Clusters.

- The total length of the pipe segment.
- The total length of potentially susceptible pipe within the segment.
- The potential consequences of a failure within a given segment.

8.3.2 The re-assessment interval justification shall be documented using the OPS-STD-0028-FOR-04 form.

8.4 SCCDA Effectiveness

8.4.1 Process Validation

8.4.2.1 Additional process validation excavations are optional as part of the Post-Assessment. While data from these excavations would be analyzed separately, the validation excavations may be planned as part of the Direct Examinations as all excavations will likely occur within the same timeframe.

8.4.2.2 At least one (1) additional Direct Examination in the Pipeline Segment may be considered at a random location to validate the process, especially if this is the first time SCCDA is applied to the Pipeline Segment. Additional validation Direct Examinations should be documented in the OPS-STD-0027-FOR-06 form.

8.4.2 Long Term Effectiveness

8.4.2.1 Criteria should be used to determine the long-term effectiveness of the SCCDA process. Performance measures can include the following:

- The total number of lines subjected to SCCDA
  - o Whether ECDA was concurrently conducted
  - o The number of SCCDA Direct Examinations (digs)
- A tally of the number and severity of SCC found (in or outside the SCCDA program)
- The number of in-service and hydrotest releases attributed to SCC
  - o Whether the line was subjected to SCCDA
  - o If so, findings from the SCCDA program, including the proximity of the releases to Direct Examination sites
- The number and types of escalations (e.g., moving a line from SCCDA to a hydrostatic pressure (re)testing or In-Line Inspection program based on SCCDA findings)

8.4.3 The Regional Corrosion Control Team Lead or Engineer shall be responsible for ensuring that criteria are used to evaluate SCCDA effectiveness. If the evaluation does not show improvement between applications, measures should be taken to re-evaluate the SCCDA application process or consider alternative methods. The completion and outcome of the validation study and any specific comments shall be documented in the Final Report. The process validation shall be completed by the Integrity Engineer and the Regional Corrosion Control Team Lead or Engineer shall verify and approve the findings.

8.4.4 See the SCC Management Program information in LO-18.001-STD for more details.

8.5 Feedback and Continuous Improvement

8.5.1 The Regional Corrosion Control Team Lead or Engineer shall be responsible for ensuring that actions are taken to continuously improve the application of the SCCDA process through a timely and quality-oriented feedback. The following types of feedback are considered:

- Data collection methods and effectiveness.
- Remaining strength evaluation.
- Mitigation.
- Additional Direct Examinations for process validation.
- Additional criteria for assessing the SCCDA effectiveness.
- Proper scheduling and monitoring of the re-assessment intervals for ensuring the long-term effectiveness of the SCCDA process.
- Lessons learned.

8.5.2 The Integrity Engineer shall be responsible for summarizing feedback and continuous comments for each project. These findings shall be verified and approved by the Regional Corrosion Control Team Lead or Engineer. All feedback or continuous improvement suggestions shall be documented by the Integrity Engineer as part of the final report.

8.5.3 The Regional Corrosion Control Team Lead or Engineer is responsible for tracking changes to the plan as a result of the feedback and for informing project teams of the changes between projects. During projects, it is the responsibility of the Regional Corrosion Control Team Lead or Engineer to inform team members of changes to the SCCDA process.

9.0 SURVEY RECORD KEEPING

9.1 In accordance with this plan, the Integrity Engineer shall be responsible for documenting forms, reports, and supporting data. This includes the approval of the SCCDA process. Approval of this SCCDA process is located in LO-18.001-STD. This documentation shall be submitted to the Regional Corrosion Control Team Lead or Engineer for verification and approval. This shall be completed following each of the four steps of the SCCDA process.

9.2 Following the verification of all forms and reports, the Regional Corrosion Control Team Lead or Engineer shall be responsible for storing all documentation and forwarding the final report to the Regional Corrosion Control Team Lead or Engineer. Documentation has required signatures prior to storage. All documentation for an SCCDA project shall be stored in the Documents folder located on the Logistics network drive and maintained for the life of the asset. Below is a summary of the data, forms, and reports that shall be documented throughout the process.

9.1.1 Project

- SCCDA Process Form:
  - o To act as a supplement to the Integrity Assessment Form .
  - o Used for approval of the project and a guide throughout the process.
  - o This form also acts a checklist for the process to ensure all activities are completed and documented.

9.1.2 Pre-Assessment

- SCCDA Data Collection Form.
- Indirect Inspection Tool Selection Form.
- SCCDA Region Analysis Form.
- Indirect Inspection Plan.
- Pre-Assessment data collected.
    - Includes assumptions made about data elements.
    - Technical justification used during tool selection.

9.1.3 Indirect Inspection

- Raw Survey Data.
- Aligned Survey Data.

9.1.4 Direct Examination

- Indication Severity Classification Form (Prioritization Column).
    - Documentation of criteria used with supporting justification.
- Excavation Summary.
- Field Data Collected.

9.1.5 Post-Assessment

- Final Report.
    - Summary of Pre-Assessment.
    - Summary of Indirect Inspection.
    - Summary of Direct Examination.
    - Mitigation.
    - Re-Assessment Interval.
    - SCCDA Effectiveness.
    - Feedback for continuous improvement.
    - Recommendations.

APPENDIX A – SCCDA PROCESS FLOW CHARTS

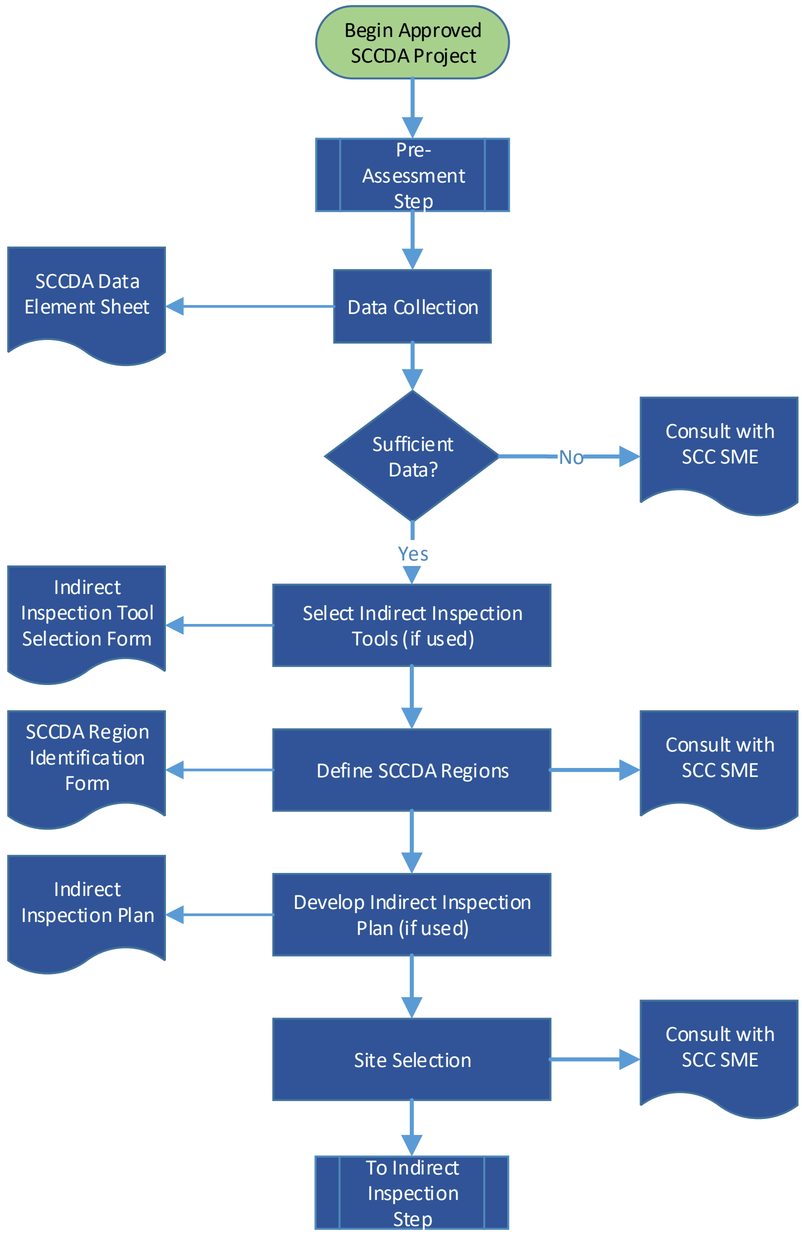


Figure 5 SCCDA Pre-Assessment Step Flow Chart

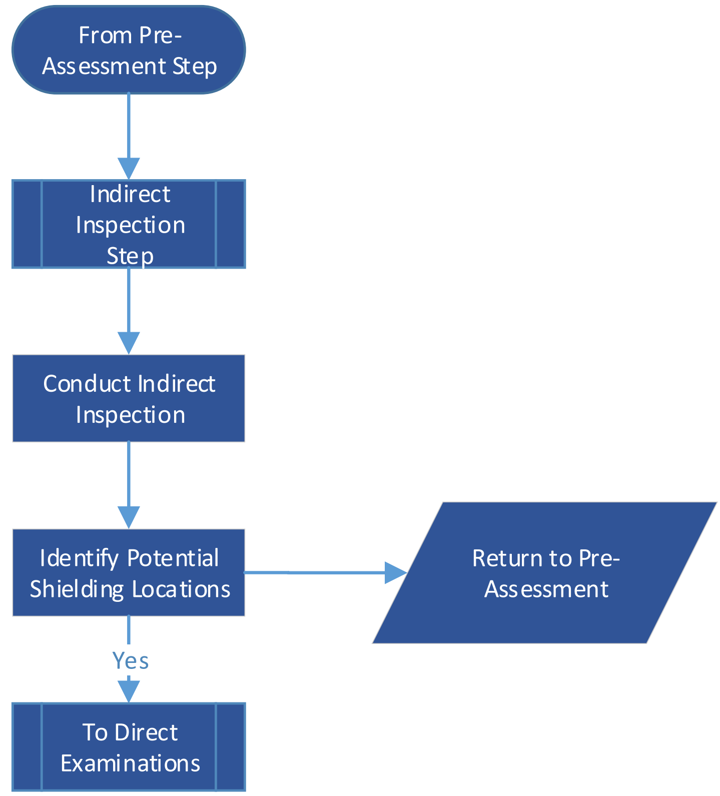


Figure 6 SCCDA Indirect Inspection Step Flow Chart

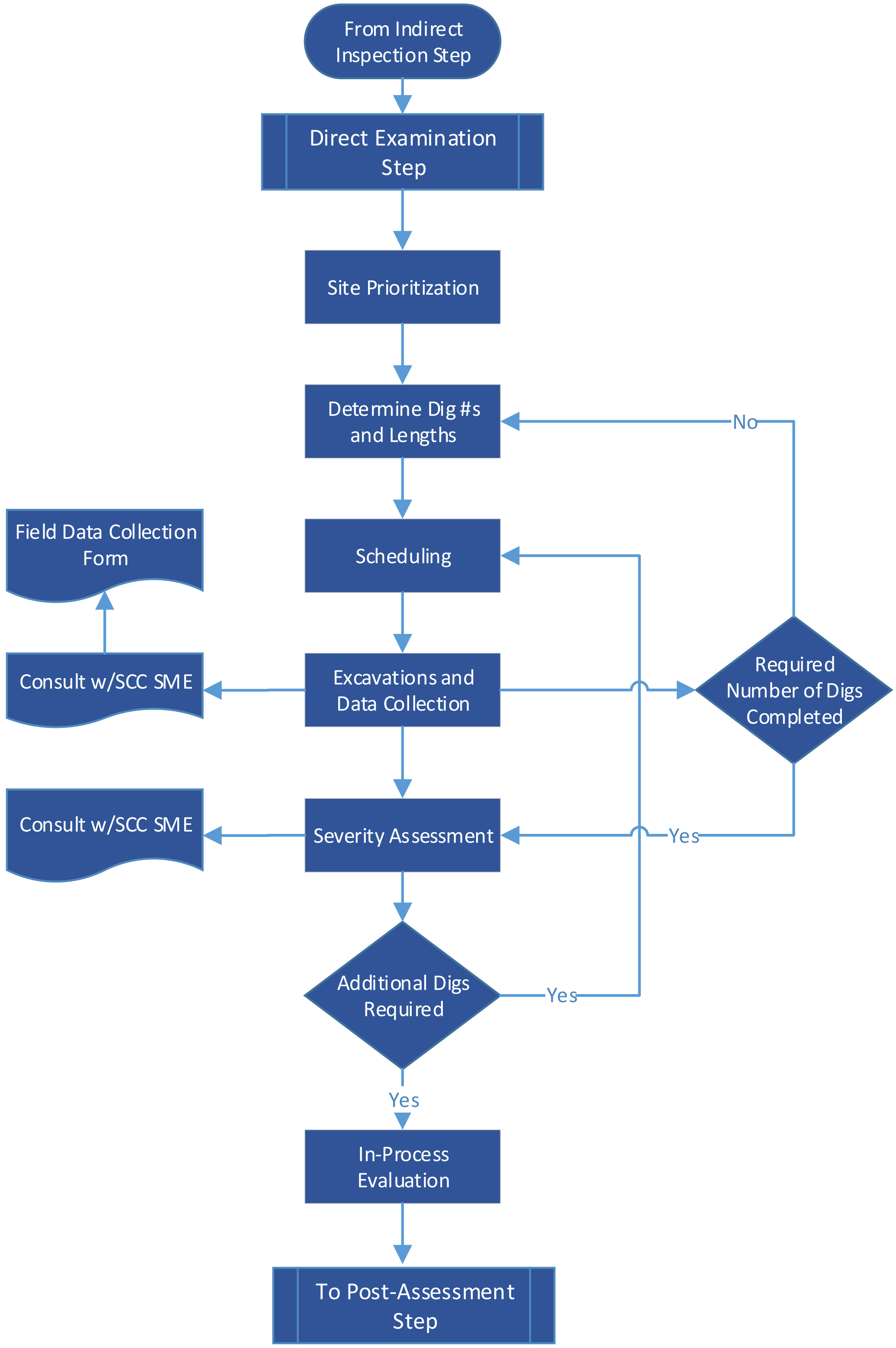


Figure 7 SCCDA Direct Examination Step Flow Chart

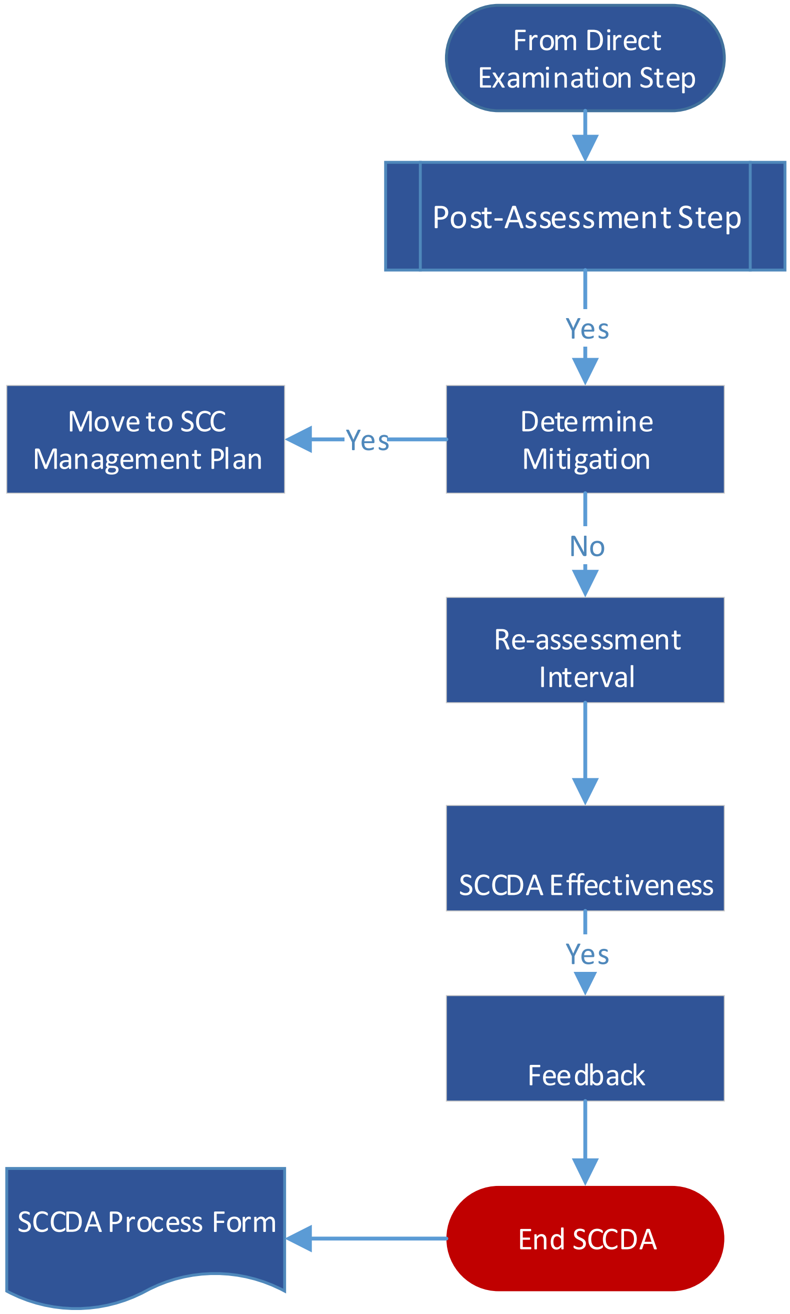


Figure 8 SCCDA Post-Assessment Step Flow Chart

	ECDA Data Element	OPS-STD-0027-FOR-02	
	FORM	Page 1 of 17	
		DATE: 4/1/2021	Rev: 0

ECDA Project Information
ECDA Project Identification:
Pipeline Identification:
Segment Identification:

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
Pipe Related					
Pipe Grade	Required	Needed for determining critical flaw sizes and remaining life.	None	Assume Grade A	
Diameter	Required	Needed for determining critical flaw sizes and remaining life.	Minor effect on survey performance and cathodic protection currents.	Do not assume, take field measurements	
Wall thickness	Required	Needed for determining critical flaw sizes and remaining life.	None	Do not assume, take field (UT) measurements	
Pipe manufacturing year	Optional	(See installation year)	Can sometimes provide an indication of the seam weld type.	None	

	ECDA Data Element	OPS-STD-0027-FOR-02	
MPLX	FORM	Page 2 of 17	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
Seam type	Desired	Tenting over long seam welds can affect survey performance; Some weld types can be susceptible to preferential corrosion.	At excavations, check for tenting and preferential corrosion.	Field identification	
Construction Related					
Installation year	Desired	Sometimes used as basis for estimating corrosion growth rates and/or coating degradation.	Sometimes used to identify typical construction techniques (see below).	None	
Route changes or modifications	Desired	May indicate where prior corrosion problems have occurred.	Significant changes (e.g., coating type) requires separate ECDA regions.	Field observations	
Route maps, aerial photos	Required	Needed to identify pipe route.	May help define boundaries for ECDA regions.	Field Notes	
Construction practices	Optional	Some trenching and backfill practices could damage the coating and/or affect survey performance.	May influence natural shielding in rocky areas and coating damage.	Field notes during excavation	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
Locations of valves and other pipeline features	Required	Major components and connections influence cathodic protection.	Uncoated components can make confuse signal interpretation.	Field notes	
Locations of casings	Required	Often requires a separate assessment.	May require operator to extrapolate nearby results.	Field notes	
Locations of bends, including miter bends and wrinkle bends.	Desired	Coatings may not match mainline pipe. Wrinkles and other geometric discontinuities can be sites for preferential corrosion.	Some components could justify separate ECDA regions.	Field notes	
Proximity to other pipelines, structures, high voltage electric transmission lines, and rail crossings	Desired	Needed to identify sources of stray or other influencing currents.	Additional surveys may be needed to identify and quantify interference.	None	
Sleeves or composite repairs	Desired	May preclude some indirect inspection tools.	May affect interpretation of results.	Field notes during excavations	
Soils and Environmental					
Pipeline Accessibility	Desired	Difficult to access areas may make surveys and	Alternate techniques, such as long wave	Field notes	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		excavations problematic.	ultrasonic or radio waves may be necessary for short pipe sections under barriers.		
Depth of cover	Required	Deep burial restricts the use of some indirect inspection techniques.	May impact current flow and interpretation of survey results.	Field measurements	
Soil characteristics/ types	Required	Some soil characteristics reduce the accuracy of various indirect inspection techniques.	Influences corrosion rates and remaining life assessment.	None	
Drainage	Optional	None	Influences corrosion rates and remaining life assessment.	None	
Topography	Required	Conditions such as rocky areas can make indirect inspections difficult or impossible.	None	None	
Type of cover	Required	Changes in cover often requires changes in survey methods and/or their application.	May reduce tool sensitivity and/or require specialized application techniques.	Field notes	
Underwater sections; river crossings	Required	Often requires a separate assessment when two survey tools	Affects interpretation of results; may require	Field notes	

	ECDA Data Element	OPS-STD-0027-FOR-02	
MPLX	FORM	Page 5 of 17	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		cannot be performed over pipeline.	alternative assessment.		
Location of river weights and anchors	Desired	Can affect survey results and/or produce spurious indications.	Affects interpretation of results.	Field notes	
Frozen ground	Optional	May impact applicability and effectiveness of some surveys.	Influences current flow and interpretation of results.	Field notes	
Corrosion Control					
CP system type (anodes, rectifiers, and locations)	Required	Detailed information needed for most surveys.	None	Do not assume, perform field investigations	
Stray current sources or locations	Desired	Needed if stray currents significantly affect survey readings or produce interference locations.	Identifying stray currents can be difficult in complicated rights of way.	Additional indirect inspection surveys to identify potential interference sites.	
Test point locations (or pipe access points)	Desired	Generally used to relate survey results to prior cathodic protection conditions.	Historic readings may demonstrate CP is stable.	None	
Prior CP surveys	Desired	Can help identify locations where prior CP is problematic.	Useful in post-assessment analysis.	Test point and rectifier records	

MPLX	ECDA Data Element	OPS-STD-0027-FOR-02	
	FORM	Page 6 of 17	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
CP maintenance history	Desired	Coating condition indicator.	Can be useful in interpreting results.	Test point and rectifier records	
Years without cathodic protection applied	Required/ Desired	Provides insight into prior corrosion.	Negatively affects ability to estimate corrosion rates and make remaining life predictions.	Assume no CP from date of first CP records.	
Years of questionable CP	Desired	None	Negatively affects ability to estimate corrosion rates and make remaining life predictions.	None	
Coating type – pipe	Required	Tape and other coatings with high dielectric constants can preclude ECDA.	Coating type may influence time at which corrosion begins and estimates of corrosion growth rate.	Do not assume, perform field investigations	
Coating type – joints	Desired	Potential for shielding exists.	Shielding due to certain joint coatings may lead to requirements for other assessment activities.	Field notes	
Coating condition	Desired	ECDA may be difficult to apply with severely degraded coatings.	None	Field notes	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
CP current demand	Desired	Increasing current demand can indicate areas where coating degradation is leading to more exposed pipe surface area.	None	Rectifier readings	
Operational					
Pipe operating temperature	Optional	Not typically important unless high.	High temperatures can locally influence coating degradation rates.	Field measurements	
Maximum Allowable Operating Stress	Required	Needed for critical flaw size calculations.	None	None	
Operating stress levels and fluctuations	Optional	Can be important when corrosion is associated with other threats (e.g., SCC, low frequency ERW).	Impacts critical flaw size and remaining life predictions.	Station records	
Monitoring programs (coupons, patrol, leak surveys, etc.)	Optional	None	May impact repair; remediation, replacement schedules.	None	

MPLX	ECDA Data Element	OPS-STD-0027-FOR-02	
	FORM	Page 8 of 17	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
Pipe inspection reports – excavation	Optional	None	Provides information on coating degradation.	Direct examinations	
Repair history/ records – such as steel/composite repair sleeves, repair locations, etc.	Required	Could introduce spurious survey indications; can identify locations with prior corrosion concerns.	Provides useful data for post-assessment analysis such as interpreting data near repairs.	Field notes	
Leak/rupture history (external corrosion)	Required	Important for identifying prior problem zones.	Pipeline with prior leaks and ruptures may be difficult to assess with ECDA.	None	
Evidence of external MIC	Desired	MIC may accelerate external corrosion rates.	None	Field measurements	
Type/frequency – third party damage	Optional	High third-party damage areas may have increased indirect inspection coating fault detects.	None	None	
Hydrotest dates/pressures	Required	Can provide basis for maximum remaining flaw size.	Influences inspection intervals.	Assume no prior Hydrotest	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
In-line inspection data	Required	Provides valuable information that complements ECDA results.	Useful post-assessment data.	None	
Casing Related					
Carrier pipe coating	Desired	Cased pipe with coatings that tend to shield cathodic protection (CP) is placed in a separate region. All other coatings that do not tend to shield CP may be placed in the same cased region. Operators may use as many regions as there are types of coatings. Carrier pipe that is bare must also be placed in a separate region.	It is envisioned that there will be two main groups of carrier pipe coatings, shielding type coatings and non-shielding type. Operators can segregate coating into additional groups if they desire.	None	
Casing materials and design	Optional	Cased pipe with problematic casing materials and designs that are known to cause or promote external corrosion require separate regions.	There are several types of casing designs and materials that behave differently from others. Among these are split sleeve type, nested type,	None	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		These may include such things as wooden spacers, metal band/runner type spacers, corrugated casings, and casings with extremely oversized or undersized annuli. Coated casings require separate regions, since they can significantly impact the resolution and interpretation of the indirect inspection data. Additionally, casings that are too long to be fully inspected by a guided wave inspection as part of ECDA step 3 (indirect assessment) are evaluated in the pre-assessment to determine if ECDA is feasible. All data gathered and analyzed as part of the pre-assessment must be	coated type and those that are only tack welded. Each requires a separate region. In addition, the centralizer design can be critical to the behavior of the casing. Certain types present more problems than others: wooden, all metal, metal banded, and directly attached can create shorted conditions if the coating fails because of age or initial method of installation. Additional design issues are end seal design, space between the carrier pipe and the casing, the likelihood of stress on the carrier pipe at the entry point, etc.		

MPLX	ECDA Data Element	OPS-STD-0027-FOR-02	
	FORM	Page 11 of 17	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		utilized in the decision process.			
Corrosion history on adjacent buried pipe segments	Desired	Casings that are in a pipe segment with known corrosion problems and are influenced by the same CP system are placed in a separate cased region.	Corrosion history on a pipe segment may be an excellent indicator for corrosion in a casing if there is a short or an electrolytic contact. Per NACE RP 0502, Table 1, these need to be in separate regions from areas that do not promote corrosion. Leak and rupture history can be dependent on corrosion history, which according to NACE RP 0502 need to be identical for each ECDA region.	None	
Each carrier pipe must have a similar cathodic protection maintenance history	Desired	Cased crossings that reside in areas that are found during the Pre-Assessment to have had intermittent or inadequate cathodic protection must be	Cathodic protection maintenance histories are important to determine the susceptibility of the carrier pipe to external corrosion and may provide additional	None	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		considered for a specific cased region.	information on the likelihood of past, present and future corrosion.		
Past knowledge of metallic or electrolytic contacts	Desired	Casings that are found to have been metallically shorted or with electrolytic current path in the past (even seasonally) and have not passed a Subpart O integrity assessment are placed in a separate cased region.	Cased crossing with metallic shorts or electrolytic contacts may have undergone external corrosion in the past and may be susceptible to external corrosion in the present and future and thus must be in separate regions.	None	
Each carrier pipe must have similar exposure to microbiologically influenced corrosion (MIC)	Desired	If the cased crossing is in an area of the operator's system that is known to have a high rate of MIC related corrosion, then the casing must be placed in a separate region.	MIC can cause the corrosion growth rate to be accelerated and may require a higher level of CP. Areas that are prone to MIC must be in a separate region.	None	
Casing construction techniques	Optional	Different construction techniques that result in changes in construction crews/contractors and installation procedures	Some construction techniques and crews may produce poor quality construction or specific construction	None	

MPLX	ECDA Data Element	OPS-STD-0027-FOR-02	
	FORM	Page 13 of 17	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		may require separate cased regions.	deficiencies, e.g., pushing centralizers together, damaging the pipe coating, etc.		
Each carrier pipe may have a similar time in service	Desired	Different pipe vintages may require different regions. Operators may rely on their experience and follow the protocols established in their ECDA procedures for buried pipe.	Time in service may be an indication of the extent of atmospheric corrosion or corrosion from shorted conditions and electrolytic contacts. Date of installation can also assist in determining construction techniques used.	None	
Casing and carrier pipe environment	Desired	Different environments surrounding the casing may require designation as separate regions, which may be consistent with the operator's ECDA procedure for buried pipe. A separate region is needed for each area with similar drainage characteristics and each area with similar soil	The environment may play a large role if there are electrolytic contact issues and shorted conditions. Some environments are more prone to causing shorts than others. Environments may play a significant role in corrosion growth rates.	None	

MPLX	ECDA Data Element	OPS-STD-0027-FOR-02	
	FORM	Page 14 of 17	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		corrosiveness properties.			
Carrier pipe stress level	Optional	The operating stress levels (e.g., 20% as compared to 72%) must be considered when establishing regions.	The stress on a carrier pipe can determine the consequence of a failure. Low stress carrier pipes will tend to leak rather than rupture while the converse is true for high stress pipes. Pipe stress levels must be considered when determining casing regions.	None	
Carrier pipe seam	Optional	Operators may follow their ECDA procedure for buried pipelines.	Selective seam corrosion can be a threat to some older pipelines with specific seam types, and thus may be in a separate region.	None	
Land use	Optional	Areas where the land use may increase corrosion due to the corrosiveness of the environment (such as processing plants) may	Land use can impact the threat of external corrosion to the carrier pipe within the casing. For example, cased crossings near	None	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		be considered for a separate region.	major highways that have snow and ice could be subject to salt contamination, i.e., low resistivity of the surrounding ground. There are other areas which could subject the pipeline to large soil loads from above, etc.		
Protection system of carrier pipe	Desired	Operators may consider the type of CP system used on the cased pipe and follow their ECDA procedure for buries pipelines	Galvanic and impressed current CP systems will behave differently and cased crossings may have the same type of CP systems in the same region	None	
Stray current and induced AC on carrier pipe	Required / Desired	Operators may follow their ECDA procedure for buried pipelines regarding stray current and induced AC history.	Stray currents, either DC or AC, can accelerate corrosion or cause corrosion, and thus cased crossing with potential stray current issues may be in separate regions.	None	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
Temperature on carrier pipe	Optional	Different operating temperatures may require separate regions, especially if high operating temperatures, coupled with moist environments, could cause degraded coatings by creating a streaming effect or causing moisture to condense in the annulus. Additionally, high operating temperatures that can accelerate corrosion may be considered when establishing cased regions.	High temperatures can accelerate atmospheric corrosion by allowing additional moisture and humidity to permeate the casing annular space. Additionally, fluctuations in temperature can cause condensation which could cause atmospheric corrosion to form on the carrier pipe.	None	
Carrier pipe exposure to humid/dry air	Desired	If the casing resides in an area that the operator has identified as an atmospheric corrosion monitoring area, such as salt marine environments, the casing may be	See the above guidance material. Cased crossing in dry air regions may be less prone to atmospheric corrosion and thus be in a separate region.	None	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		placed in a separate region.			
Carrier pipe design	Optional	Operators may follow their ECDA procedure for buried pipelines. Each carrier pipe may have a similar type pipe design; maximum allowable operating pressure, diameter, class location, end loading stresses and other design factors.	Dissimilar designs with regard to piping design, MAOP, diameter and other issues can affect both the likelihood and consequence of failure and thus may be in separate regions.	None	

Integrity Engineer: *Compiled Data.*	
Signature:	Date:
Regional Corrosion Control Team Lead or Engineer: *Reviewed and Verified.*	
Signature:	Date:

MPLX	ECDA Regional Analysis	OPS-STD-0027-FOR-04	
	FORM	Page 1 of 3	
		DATE: 4/1/2021	Rev: 0

ECDA Project Information

ECDA Project Identification:
Pipeline Identification:
Segment Identification:

Section	Uncased / Cased Pipe	Location	Start Station	End Station	Length (Feet)	Assigned Region #
1						
2						
3						
4						
5						
6						

Item #	Attribute	Separate Region Required?	Comments	Additional Guidance Material	Section 1	2	3	4	5	6
Uncased Pipe										
1	Age	Maybe	Sometimes used as basis for estimating corrosion growth rates and/or coating degradation.	Sometimes used to identify typical construction techniques.						
2	Coating	Maybe	Tape and other coatings with high dielectric constants can preclude ECDA.	Coating type may influence time at which corrosion begins and estimates of corrosion growth rate.						

	ECDA Regional Analysis	OPS-STD-0027-FOR-04	
	FORM	Page 2 of 3	
		DATE: 4/1/2021	Rev: 0

Item #	Attribute	Separate Region Required?	Comments	Additional Guidance Material	Section 1	2	3	4	5	6
3	CP Type	Maybe	Detailed information needed for most surveys.	CP type may influence protection level or type of surveys.						
4	Soil	Maybe	May have an impact on the corrosion rate.	Sandy soils may have different corrosion rates than clay soils						
5	Drainage	Maybe	May have an impact on the corrosion rate.	None						
6	Slope	Maybe	May have an impact on the corrosion rates based on seasonal changes.	None						
7	Special Conditions	Maybe	Presence of stray current or other conditions may impact survey tool selection or corrosion rates.	None						
Cased Pipe										
8	Corrosion history on adjacent pipe	Maybe	Casings that are in a pipe segment with known corrosion problems and are influenced by the same CP system are placed in a separate cased region.	Corrosion history on adjacent pipe						
9	Metallic or electrolytic contacts	Yes	Casings that are found to have been metallically shorted or with electrolytic current path in the past (even seasonally) and have not passed a Subpart O integrity assessment are placed in a separate cased region	Metallic or electrolytic contacts						

Item #	Attribute	Separate Region Required?	Comments	Additional Guidance Material	Section 1	2	3	4	5	6
10	Exposure to MIC	Yes	If the cased crossing is in an area of the operator's system that is known to have a high rate of MIC related corrosion, then the casing must be placed in a separate region.	Exposure to MIC						
11	Carrier Pipe Exposure to Humid/Dry Air	Maybe	If the casing resides in an area that the operator has identified as an atmospheric corrosion monitoring area, such as salt marine environments, the casing may be placed in a separate region.	Carrier Pipe Exposure to Humid/Dry Air						

Integrity Engineer: *Compiled Data.*	
Signature:	Date:
Regional Corrosion Control Team Lead or Engineer: *Reviewed and Verified.*	
Signature:	Date:

MPLX	ECDA/SSCDA Dig Data Collection	OPS-STD-0027-FOR-06	
	FORM	Page 1 of 11	
		DATE: 4/1/2021	Rev: 0

ECDA/SCCDA Project Information

ECDA/SSCDA Project Identification:
Pipeline Identification:
Segment Identification:

(1) Project Information	
Project Number:	Date:
Line Name/Number:	Contractor/Inspector:
ECDA/SCCDA Region #:	Dig Site Number #:
(2) Site Location Information	
Alignment Sheet Number:	GPS Latitude:
US/DS Reference Description:	GPS Longitude:
US/DS Reference Inventory Number:	Location of Examination (City/County, State):
(3) Specified Pipe Information	
Pipe Outside Diameter:	Reference Girth Weld (RGW) Number:
Nominal Wall Thickness:	Joint Length:
Pipe Seam Type:	Clock Position of L-Seam:
Pipe Manufacturer (if known):	
Material Specification:	
Coating Type ☐ Asphalt ☐ Tape ☐ Coal Tar ☐ Liquid Epoxy ☐ FBE ☐ Wax ☐ Extruded PE ☐ Other:	
Girth Weld Coating ☐ Tape ☐ Cold Mastic ☐ Hot Mastic ☐ Liquid Epoxy ☐ Wax ☐ Other:	
Outer Wrap: ☐ Yes, Type: ☐ No	
Cathodic Protection System: ☐ Impressed ☐ Galvanic ☐ None Date Installed:	
Additional Notes:	

MPLX	ECDA/SSCDA Dig Data Collection	OPS-STD-0027-FOR-06	
	FORM	Page 2 of 11	
		DATE: 4/1/2021	Rev: 0

(4) Dig Site Information

Reference Feature: | Distance to Feature:

Length of Pipe Exposed: feet inches | Depth of Cover: feet inches

Terrain Conditions

☐ Inclined ☐ Level ☐ Ridged ☐ Depressed ☐ Undulating ☐ Side Slope

Soil Type

☐ Fluvial ☐ Till Deposits ☐ Organic ☐ Lacustrine ☐ Rock ☐ Alluvial ☐ Clay ☐ Sand

Soil Condition: ☐ Wet ☐ Moist ☐ Dry ☐ Frozen ☐ Other | Soil pH:

Drainage: ☐ Very Poor ☐ Poor ☐ Imperfect to Poor ☐ Good ☐ Not Identified

Soil Sample Taken: ☐ Yes ☐ No | Sample ID(s):

Soil Resistivity Performed: ☐ Wenner 4-Pin ☐ Soil Box ☐ Single Probe ☐ No

Wenner 4-Pin Method: ☐ Parallel to Pipe ☐ Perpendicular to Pipe Distance from Pipe (feet):

Pin Separation (feet)	Dial Reading	Multiplier	Resistance (ohms)	Resistivity (ohm-cm)

Weather Conditions: | Ambient Temperature (°F):

Additional Notes:

MPLX	ECDA/SSCDA Dig Data Collection	OPS-STD-0027-FOR-06	
	FORM	Page 3 of 11	
		DATE: 4/1/2021	Rev: 0

(5) Observed Coating

Coating Type

☐ Asphalt ☐ Tape ☐ Coal Tar ☐ Liquid Epoxy ☐ FBE ☐ Wax ☐ Extruded PE ☐ Other:

Girth Weld Coating

☐ Tape ☐ Cold Mastic ☐ Hot Mastic ☐ Liquid Epoxy ☐ Wax ☐ Other:

Outer Wrap: ☐ Yes, Type: ☐ No

Coating Thickness (mils): 12 o'clock: 3 o'clock: 6 o'clock: 9 o'clock:

Coating Thickness Location:

Additional Notes:

(6) Coating Condition

Condition: ☐ Excellent ☐ Good ☐ Fair ☐ Poor ☐ Very Poor

Bonding Adhesion: ☐ Good ☐ Fair ☐ Poor | Test Type:

Moisture Underneath Coating: ☐ Yes ☐ No | Moisture pH: | Pipe Surface pH:

Type of Coating Damage

☐ Wrinkles ☐ Cuts ☐ Holidays ☐ Blisters ☐ Dents ☐ Test Bar Marks ☐ Disbondment ☐ Other:

Coating Sample Taken: ☐ Yes ☐ No | Sample ID:

Additional Notes:

	EDCA/SCCDA Dig Data Collection	OPS-STD-0027-FOR-06	
MARATHON	FORM	Page 4 of 11	
		DATE: 4/1/2021	Rev: 0

(6a) Coating Damage Listing

Damaged Area No.	Distance from Reference (ft, in)	Upstream or Downstream	Pipe Orientation	Length (in)	Width (in)	Diameter (in)	Moisture Underneath Coating?	pH	Bonding Adhesion	Type of Damage	Notes	Photograph Taken?
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												

MARATHON	EDCA/SCCDA Dig Data Collection	OPS-STD-0027-FOR-06
	FORM	Page 5 of 11
		DATE: 4/1/2021 | Rev: 0

(6b) Coating Damage Sketch	☐ None

	EDCA/SCCDA Dig Data Collection	OPS-STD-0027-FOR-06	
	FORM	Page 6 of 11	
		DATE: 4/1/2021	Rev: 0

(7) External Metal Loss/Mechanical Damage

External Metal Loss Observed

☐ Uniform ☐ Localized ☐ Scattered ☐ Pitting ☐ Isolated Pit ☐ None

Products/Deposits Observed

☐ Pipe Surface ☐ Coating Surface ☐ Other Location: ☐ None

Description of Products/Deposits

Location	Description	Color	Texture	Bonding	pH

Product Sample Taken: ☐ Yes ☐ No Sample ID:

Field Chemical Tests

Sample			CO_3^{2-}	S^{2-}	Fe^{2+}	Fe^{3+}	Ca^{2+}	pH
ID	Description	Location						

Mechanical Damage Observed

☐ Dent ☐ Gouge ☐ Linear Indication ☐ Welding Related ☐ Other: ☐ None

Wall Thickness (inches): 12 o'clock: 3 o'clock: 6 o'clock: 9 o'clock:

Longitudinal Seam: O'clock Position ☐ None

Additional Notes:

MARATHON	EDCA/SCCDA Dig Data Collection	OPS-STD-0027-FOR-06	
	FORM	Page 7 of 11	
		DATE: 4/1/2021	Rev: 0

(8) Casing Information				☐ N/A
Diameter (inches):	Wall Thickness (inches):	Coated: ☐ Yes ☐ No		
Casing Vents: ☐ 2 ☐ 1 ☐ None	Condition:			
End Seals: ☐ Yes ☐ No	Upstream Condition:	Downstream Condition:		
Test Leads: ☐ Upstream ☐ Downstream ☐ None	C/S On Potential (VDC):			
Annulus Space Electrolyte Present in Upstream End: ☐ Completely Full ☐ Half Full ☐ End with Some ☐ None Electrolyte Present in Downstream End: ☐ Completely Full ☐ Half Full ☐ End with Some ☐ None				
Electrolyte Sample Taken: ☐ Yes ☐ No	Sample ID:			
Casing Thickness (inches):	12 o'clock:	3 o'clock:	6 o'clock:	9 o'clock:
Additional Notes:				

(9) SCC Investigation Results				☐ N/A
Pipe Preparation Method:	☐ Grit Blasting	☐ Water Blasting	☐ Walnut Shells	☐ Wire Wheel
MPI Method:	☐ Dry	☐ Wet Visual	☐ Wet Fluorescent	☐ Black on White
Electrolyte Under Coating:	☐ Yes, pH:	☐ No		
Additional Notes:				

MARATHON	ECDA/SCCDA Dig Data Collection	OPS-STD-0027-FOR-06	
	FORM	Page 8 of 11	
		DATE: 4/1/2021	Rev: 0

(10) SCC Investigation Details

☐ N/A

ID #	Axial Start (in)	Circum-ferential Start (O'clock)	Axial Length (in)	Circum-ferential Width (in)	Maximum Interlinked Length (in)	Seam Weld (O'clock)	Wall Thickness (in)	Depth (in)	Method Used to Estimate Depth	Proximity to Stress Risers	Comments

	ECDA/SCCDA Dig Data Collection	OPS-STD-0027-FOR-06	
	FORM	Page 9 of 11	
		DATE: 4/1/2021	Rev: 0

(11) Pipe Condition Sketch

MARATHON	EDCA/SCCDA Dig Data Collection	OPS-STD-0027-FOR-06	
	FORM	Page 10 of 11	
		DATE: 4/1/2021	Rev: 0

(12) Structure-to-Electrolyte Potentials

Cathodic Protection System Status

☐ On ☐ Off ☐ Interrupting ☐ Polarizing ☐ Depolarizing ☐ Information Unavailable

Structure-to-Electrolyte (P/S) Potential Data at Dig Site	
AC P/S Potential (VAC CSE):	
DC "On" P/S Potential (-VDC CSE):	DC "Interrupted" P/S Potential (-VDC CSE):
Structure-to-Electrolyte (P/S) Potential Data at Nearest Test Station	
Test Station Distance from Dig Site (ft):	AC P/S Potential (VAC CSE):
DC "On" P/S Potential (-VDC CSE):	DC "Interrupted" P/S Potential (-VDC CSE):
Additional Notes:	

(13) Remedial Action

Reinforcing Sleeve:	☐ Type A	☐ Type B	☐ Other:	☐ None
☐ Cut-Out	Material Specification for Replacement:			
☐ Recoat	Coating Used:			
Actual Station Where Repair was Completed:				
Additional Notes:				

MARATHON	EDCA/SCCDA Dig Data Collection	OPS-STD-0027-FOR-06
	FORM	Page 11 of 11 DATE: 4/1/2021 Rev: 0

(14) Summary of Photographs

Direct Examination:	Casing Features, if applicable:	SCC Colonies, if applicable:	Other Photographs:
▪ Excavation Site ▪ Reference Feature ▪ Adjacent Appurtenances ▪ Terrain Conditions ▪ Soil Profile ▪ Coating Condition ▪ Products ▪ Pipe Surface Before Surface Preparation	▪ Crossing ▪ Casing Vent(s) ▪ Casing Condition ▪ End Seal Condition ▪ End Seal Condition ▪ Annulus Space (upstream) ▪ Annulus Space (downstream)	▪ SCC 1 Colony ▪ SCC 2 Colony ▪ SCC 3 Colony ▪ SCC 4 Colony ▪ SCC 5 Colony ▪ SCC 6 Colony ▪ SCC 7 Colony ▪ SCC 8 Colony ▪ SCC 9 Colony ▪ SCC 10 Colony ▪ More	▪ Other: ▪ Other: ▪ Other: ▪ Other: ▪ Other: ▪ Other: ▪ Other: ▪ Other: ▪ Other: ▪ Other: ▪ Other:

Integrity Engineer: *Compiled Data.*	
Signature:	Date:
Regional Corrosion Control Team Lead: *Reviewed and Verified.*	
Signature:	Date:

MPLX	ECDA Re-Assessment Interval	OPS-STD-0027-FOR-07	
	FORM	Page 1 of 3	
		DATE: 4/1/2021	Rev: 0

ECDA Project Information
ECDA Project Identification:
Pipeline Identification:
Segment Identification:

Region #	Dig Site #	NPS	Pipe OD (in)	t (in)	Pipe Steel Grade	MOP (psi)	Yield Pressure, YP (psi)	MAOP (psi)	Burst Pressure, BP (psi)	FoS (Pf/MOP)	% SYMS	MPR	RPR	SM [RPR-MPR]	GR (mpy)	Remaining Life – TF (years)	Remaining Life – TL (years)	Re-Assessment Interval Based on RL (years)	Re-Assessment Interval	Comments

[1] If Category 4, reduce pressure or shut down and conduct an integrity assessment within 90 days.
[1] If Category 3, reduce pressure until hydrotest or in-line inspection is completed (within 2 years)
[1] If Category 2, consider a pressure reduction until hydrotest or in-line inspection is completed (within 2 years)
[1] If Category 1, conduct a minimum of two additional direct examinations, then follow category of any SCC found

MARATHON	ECDA Re-Assessment Interval	OPS-STD-0027-FOR-07	
	FORM	Page 2 of 3	
		DATE: 4/1/2021	Rev: 0

Region #	Dig Site #	NPS	Pipe OD (in)	t (in)	Pipe Steel Grade	MOP (psi)	Yield Pressure, YP (psi)	MAOP (psi)	Burst Pressure, BP (psi)	FoS (Pf/MOP)	% SYMS	MPR	RPR	SM [RPR-MPR]	GR (mpy)	Remaining Life – TF (years)	Remaining Life – TL (years)	Re-Assessment Interval Based on RL (years)	Re-Assessment Interval	Comments

Region #	Dig Site #	NPS	Pipe OD (in)	t (in)	Pipe Steel Grade	MOP (psi)	Yield Pressure, YP (psi)	MAOP (psi)	Burst Pressure, BP (psi)	FoS (Pf/MOP)	% SYMS	MPR	RPR	SM [RPR-MPR]	GR (mpy)	Remaining Life – TF (years)	Remaining Life – TL (years)	Re-Assessment Interval Based on RL (years)	Re-Assessment Interval	Comments

Integrity Engineer: *Compiled Data.*	
Signature:	Date:
Regional Corrosion Control Team Lead or Engineer: *Reviewed and Verified.*	
Signature:	Date:

	SCCDA Process	OPS-STD-0028-FOR-01	
	FORM	Page 1 of 5	
		DATE: 4/1/2021	Rev: 0

SCCDA Project Information
SCCDA Project Identification:
Pipeline Identification:
Segment Identification:

This form is to be used as a supplement to the Integrity Assessment Form (LIM/GIM030-F1). The form includes a section for each step of the SCCDA process. Each section contains a list of activities for each step, a list of required forms and documentation, a section to enter what criteria has been used for a first-time application project, and a verification section for the responsible individuals.

Form Sections:

1. Pre-Assessment Step
2. Indirect Inspection Step
3. Direct Examination Step
4. Post-Assessment Step

MPLX	SCCDA Process	OPS-STD-0028-FOR-01	
	FORM	Page 2 of 5	
		DATE: 4/1/2021	Rev: 0

1) Pre-Assessment Step

Step Activities

The Pre-Assessment Step includes the following activities:

- Data collection
- Identification of SCCDA regions
- Development of an Indirect Inspection Plan
- Preliminary selection of SCCDA direct examination sites

Forms and Documentation

The Pre-Assessment Step Requires the following documentation:

- ☐ SCCDA Data Elements Form
- ☐ SCCDA Region Identification Form
- ☐ Indirect Inspection Plan
- ☐ SCCDA Site Selection Form

Verification and Approval

Integrity Engineer: *All required items have been documented.*

Signature:	Date:

Regional Corrosion Control Team Lead or Engineer:
Documentation, Forms, and Conclusions have been verified.

Signature:	Date:

2) Indirect Inspection Step

Step Activities

The Indirect Inspection Step includes the following activities:

- Conducting the indirect inspections
- Data alignment

Forms and Documentation

The Indirect Inspection Step Requires the following documentation:

- □ Indirect inspection survey data
- □ Aligned data

Verification and Approval

Integrity Engineer: *All required items have been documented.*	
Signature:	Date:
Regional Corrosion Control Team Lead or Engineer: *Documentation, Forms, and Conclusions have been verified.*	
Signature:	Date:

3) Direct Examination Step

Step Activities

The Direct Examination Step includes the following activities:

- Scheduling excavations
- Excavation and data collection
- SCC damage and data collection
- Remaining strength evaluation

Forms and Documentation

The Direct Examination Step Requires the following documentation:

- ☐ Excavation Summary Form
- ☐ Excavation Data Collection Form(s)

Verification and Approval

Integrity Engineer: *All required items have been documented.*	
Signature:	Date:
Regional Corrosion Control Team Lead or Engineer: *Documentation, Forms, and Conclusions have been verified.*	
Signature:	Date:

MPLX	SCCDA Process	OPS-STD-0028-FOR-01	
	FORM	Page 5 of 5	
		DATE: 4/1/2021	Rev: 0

4) Post-Assessment Step

Step Activities

The Post-Assessment Step includes the following activities:

- Determining mitigation
- Definition of re-assessment intervals
- Feedback for continuous improvement

Forms and Documentation

The Post-Assessment Step Requires the following documentation, will are included in a single final report:

- ☐ Mitigative activities
- ☐ Remaining Strength Form
- ☐ Define re-assessment interval
- ☐ Feedback
- ☐ Recommendations
- ☐ Summary of each SCCDA step
- ☐ Integrity Assessment Form (LIM/GIM030-F1)

Verification and Approval

Integrity Engineer: *All required items have been documented.*

Signature:	Date:

Regional Corrosion Control Team Lead or Engineer:
Documentation, Forms, and Conclusions have been verified. Approval of Re-Assessment Interval.

Signature:	Date:

	SCCDA Data Element	OPS-STD-0028-FOR-02	
MPLX	FORM	Page 1 of 12	
		DATE: 4/1/2021	Rev: 0

SCCDA Project Information

SCCDA Project Identification:
Pipeline Identification:
Segment Identification:

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
Pipe Related					
Pipe grade	Required	Needed for determining nominal hoop stress level, critical flaw sizes and estimated failure pressure	None	Assume most likely grade for stress level determinations; Assume Grade A or B for failure pressure calculations	
Diameter	Required	Needed for determining nominal hoop stress, critical flaw sizes, and estimated failure pressure	None	Do not assume, take field measurements	
Wall thickness	Required	Needed for determining nominal hoop stress, critical flaw sizes, and estimated failure pressure	None	Do not assume, take field (UT) measurements	
Pipe manufacturer	Optional	Near neutral pH SCC found preferentially on Youngstown Sheet and	None	None	

MPLX	SCCDA Data Element	OPS-STD-0028-FOR-02	
	FORM	Page 2 of 12	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		Tube ERW pipe in the 1950s. Reported to be a significant predictor for one pipeline system			
Seam type	Desired	Near neutral pH SCC found preferentially in the HAZ of some ERW pipe	None	Field identification	
Coating surface preparation	Required	Shot peening or grit blasting can be beneficial by introducing compressive residual stresses at the surface, inhibiting crack initiation, and by removing mill scale, making it difficult to hold the potential in the critical range for high-pH SCC.	None	None	
Shop coating type	Required	To date, SCC has not been reported for pipe with undamaged FBE coating or with extruded polyethylene coating	None	Do not assume, perform field investigations	
Bare pipe	Desired	SCC has been observed on bare pipe in high-resistivity soils.	None	None	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
Hard spots	Desired	There have been instances in which near-neutral-pH SCC has occurred preferentially in hard spots, which can be located by ILI that measures residual magnetism.	None	None	
Construction Related					
Installation year	Required	Sometimes used as basis for estimating SCC growth rates and/or coating degradation	Sometimes used to identify typical construction techniques (see below)	None	
Route changes or modifications	Desired	May indicate locations where local stresses are elevated and/or where coating application may be different from surrounding pipe.	Significant changes could require separate SCCDA regions	Field observations	
Route maps, aerial photos	Desired	Needed to identify pipe route	May help define boundaries for SCCDA regions	Field Notes	
Construction practices	Desired	Some trenching and backfill practices could damage the coating and/or affect survey	May influence natural shielding in rocky areas and coating damage	Field notes during excavation	

	SCCDA Data Element	OPS-STD-0028-FOR-02	
	FORM	Page 4 of 12	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		performance; presence of rock in the backfill can introduce dents and locally elevated stresses; time between burying pipe and installation of cathodic protection might be important			
Surface preparation for field coating	Required	Mill scale promotes potential in critical range for high-pH SCC	None	None	
Field coating type	Required	High-pH SCC found under coal tar, asphalt, and tape. Near-neutral-pH SCC most prevalent under tape but also found under asphalt. Weather conditions during construction also may be important in affecting coating condition.	None	None	
Locations of weights and anchors	Desired	Near-neutral-pH SCC has been found under buoyancy-control weights			

	SCCDA Data Element	OPS-STD-0028-FOR-02	
MPLX	FORM	Page 5 of 12	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
Locations of valves and other pipeline features	Optional	Can influence cathodic protection	None	Field notes	
Locations of casings.	Desired	CP shielding and coating damage more likely within casings	May be important for accurately locating and characterizing each site.	Field notes	
Locations of bends, including miter bends and wrinkle bends.	Desired	Coatings may not match mainline pipe. May indicate unusual residual and secondary stresses	Some components could justify separate SCCDA regions	Field notes	
Locations of dents	Desired	May indicate locations of residual stresses	None	None	
Soils and Environmental					
Soil characteristics/types	Desired	No known correlation between soil type and high-pH SCC, except for some evidence that high sodium or potassium levels might promote development of concentrated carbonate/bicarbonate solutions under disbonded coatings. Some success has been	Might be important, especially for near neutral pH SCC	None	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		experienced in correlating near-neutral-pH SCC with specific soil types			
Drainage	Desired	Has been correlated with both high-pH and near-neutral-pH SCC	None	None	
Topography	Desired	Has been correlated with both high-pH and near-neutral-pH SCC, possibly related to effect on drainage. Also, circumferential near-neutral-pH SCC has been observed on slopes where soil movement has occurred.	None	None	
Land use (current/past)	Desired	No obvious correlations have been found, but use of fertilizer might affect soil chemistry as related to trapped water under disbonded coatings.	None	Field notes	
Groundwater	Desired	Groundwater conductivity affects the	None	Field measurements	

MPLX	SCCDA Data Element	OPS-STD-0028-FOR-02	
	FORM	Page 7 of 12	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		throwing power of CP systems.			
Locations of river crossings	Desired	Affects soil moisture/drainage	None	Field notes	
Soil carbon dioxide	Desired	Reasonable to expect that probability of cracking increases with rate of CO_2 generation. Rate of CO_2 generation increases with increasing temperature and soil moisture content.	None	Field measurements	
Transitional environmental conditions	Optional	SCC is often associated with sites where the environmental conditions change, either seasonally or along the length or circumference of the pipe	None	Field notes	
Corrosion Control					
CP system type (anodes, rectifiers, and locations)	Desired	Adequate CP can prevent SCC if it reaches under disbonded coatings	None	Do not assume, perform field investigations	

	SCCDA Data Element	OPS-STD-0028-FOR-02	
	FORM	Page 8 of 12	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
CP Evaluation criteria	Optional	Adequate CP can prevent SCC if it reaches under disbonded coatings	None	Field investigations	
CP shielding	Desired	Commonly associated with near neutral pH SCC	None	None	
CP maintenance history	Optional	Adequate CP can prevent SCC if it reaches under disbonded coatings	None	None	
Years without CP applied	Desired	For high-pH SCC, absence of CP might allow harmful oxides to form on pipe surface. For near-neutral-pH SCC occurring at or near the open-circuit potential, absence of CP could allow SCC to proceed.	None	None	
CIS and test station information	Desired	Although high-pH SCC occurs in a narrow range of potentials (typically between –575 and –825 mV vs. copper/copper sulfate [Cu/CuSO4] depending on temperature and	Important factor to consider for both high-pH and near-neutral-pH SCC	None	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		solution composition), it has been observed on pipe that appeared to be adequately cathodically protected, because the actual potential at the pipe surface can be less negative than the aboveground measurements because of shielding by disbonded coatings. Nevertheless, locations of cracks might correlate with CP history, especially if problems had been encountered in the past			
Coating fault survey information	Desired	Because SCC requires coating faults, indications of coating condition might help locate probable areas	None	None	
Coating system and condition	Required	The coating system (coating type, surface condition, etc.) is an important factor in determining SCC	None	None	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		susceptibility and the type of SCC that occurs. Because SCC requires coating faults, indications of coating condition might help locate probable areas			
Operational					
Pipe operating temperature	Required	Elevated temperatures have strong accelerating effect on high-pH SCC. For near-neutral-pH SCC, temperature probably has little effect on crack growth rate, but elevated temperatures can contribute to coating deterioration.	Important, especially for high-pH SCC.	None	
Operating stress levels and fluctuations	Required	Stress must be above a certain threshold for SCC to occur. Fluctuating stresses can significantly reduce the threshold stress.	Impacts SCC initiation, critical flaw size, and remaining life predictions.	None	
Specific types of pressure fluctuations	Optional	Certain types of pressure fluctuations, such as unload/reload	Locations with an increased number of such cycles may be	None	

MPLX	SCCDA Data Element	OPS-STD-0028-FOR-02	
	FORM	Page 11 of 12	
		DATE: 4/1/2021	Rev: 0

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
		cycles, high frequency fluctuations, variable load and frequency cycles, underload and overload cycles, are associated with near-neutral pH SCC. Conversely, the absence of such types of pressure fluctuation can result in crack dormancy.	more susceptible to near-neutral pH SCC. May be useful for excluding the possibility of high-pH SCC on liquid lines		
Leak/rupture history (SCC)	Required	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	None	None	
Direct inspection and repair history	Required	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	None	None	
Hydrostatic retest history	Required	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	None	None	

Data Element	Need	Rationale	Other Considerations	Alternative (if data not readily available)	Available Data
ILI data from crack-detecting pig	Required	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	None	None	
ILI data from metal-loss pig	Desired	If a metal-loss pig indicates corrosion on a tape-coated pipe where there is no apparent indication of a holiday, the coating is probably disbonded and shielding the pipe from CP, a condition in which SCC, especially near-neutral-pH SCC, has been observed.	None	None	

Integrity Engineer: *Compiled Data.*	
Signature:	Date:
Regional Corrosion Control Team Lead or Engineer: *Reviewed and Verified.*	
Signature:	Date:

MPLX	SCCDA Regional Analysis	OPS-STD-0028-FOR-03	
	FORM	Page 1 of 3	
		DATE: 4/1/2021	Rev: 0

SCCDA Project Information

SCCDA Project Information
SCCDA Project Identification:
Pipeline Identification:
Segment Identification:

Section	Location	Start Station	End Station	Length (Feet)	Assigned Region #
1					
2					
3					
4					
5					
6					

Item #	Attribute	Separate Region Required?	Comments	Additional Guidance Material	Section					
					1	2	3	4	5	6
1	Prior SCC	Yes	Region should be defined based on conditions similar to those at the location(s) where SCC has been found.	Important parameters to consider are all of the following.						

MPLX	SCCDA Regional Analysis	OPS-STD-0028-FOR-03	
	FORM	Page 2 of 3	
		DATE: 4/1/2021	Rev: 0

Item #	Attribute	Separate Region Required?	Comments	Additional Guidance Material	Section 1	2	3	4	5	6
2	Coating Type	Yes	Different types of coatings correspond to different SCC susceptibilities. See SCC Management Program (LIM031).	None						
3	Terrain Conditions	Maybe	See SCC Management Program (LIM031), which references the CEPA guidance; locations that do not match the CEPA categories may be given a separate region (and considered low likelihood).	Different susceptible conditions apply for different coating types.						
4	Operating Stress/Wall Thickness	Yes	Areas over 60% SMYS should have a separate region; significant changes in wall thickness may have a separate region.	Applies more to high pH SCC than near neutral pH SCC.						
5	Locally Elevated Stresses	Maybe	Correlated with near neutral pH SCC.	Examples include dents and bends.						
6	Temperature	Yes	Locations with historic or current operating temperatures over 100 degrees F should have a separate region.	High pH SCC only						

Item #	Attribute	Separate Region Required?	Comments	Additional Guidance Material	Section 1	2	3	4	5	6
7	Age	Maybe	None	None						
8	Evidence of cathodic protection shielding	Yes	Shielded areas should be in a separate region.	None						

Integrity Engineer: *Compiled Data.*	
Signature:	Date:
Regional Corrosion Control Team Lead or Engineer: *Reviewed and Verified.*	
Signature:	Date:

MPLX	SCCDA Re-Assessment Interval	OPS-STD-0028-FOR-04	
	FORM	Page 1 of 3	
		DATE: 4/1/2021	Rev: 0

SCCDA Project Information

SCCDA Project Identification:

Pipeline Identification:

Segment Identification:

Region #	Dig Site #	Pipe OD (in)	t (in)	Pipe Steel Grade	MOP (psi)	Yield Pressure, YP (psi)	MAOP (psi)	Burst Pressure, BP (psi)	Method Used to Calculate Burst Pressure	BP/YP	Is BP ≤ 110% MOP (Category 4)?	Is BP > 110% and ≤ 125% MOP (Category 3)?	Is BP > 125% MOP and ≤ 110% YP (Category 2)?	Is BP>110% YP (Category 1)?	Is d<10% WT and L < 2 inches (Category 0)?	Move to Hydrotest/ILI Program (Category 2, 3 and 4)?	Type of Repair Made	Re-Assessment Interval	Comments

[1] If Category 4, reduce pressure or shut down and conduct an integrity assessment within 90 days.
[1] If Category 3, reduce pressure until hydrotest or in-line inspection is completed (within 2 years)
[1] If Category 2, consider a pressure reduction until hydrotest or in-line inspection is completed (within 2 years)
[1] If Category 1, conduct a minimum of two additional direct examinations, then follow category of any SCC found

MARATHON	SCCDA Re-Assessment Interval	OPS-STD-0028-FOR-01	
	FORM	Page 2 of 3	
		DATE: 4/1/2021	Rev: 0

Region #	Dig Site #	Pipe OD (in)	t (in)	Pipe Steel Grade	MOP (psi)	Yield Pressure, YP (psi)	MAOP (psi)	Burst Pressure, BP (psi)	Method Used to Calculate Burst Pressure	BP/YP	Is BP VI 110% MOP (Category 4)?	Is BP > 110% and VI 125% MOP (Category 3)?	Is BP > 125% MOP and VI 110% YP (Category 2)?	Is BP>110% YP (Category 1)?	Is d<10% WT and L < 2 inches (Category 0)?	Move to Hydrotest/ILI Program (Category 2, 3 and 4)?	Type of Repair Made	Re-Assessment Interval	Comments

Region #	Dig Site #	Pipe OD (in)	t (in)	Pipe Steel Grade	MOP (psi)	Yield Pressure, YP (psi)	MAOP (psi)	Burst Pressure, BP (psi)	Method Used to Calculate Burst Pressure	BP/YP	Is BP VI 110% MOP (Category 4)?	Is BP > 110% and VI 125% MOP (Category 3)?	Is BP > 125% MOP and VI 110% YP (Category 2)?	Is BP>110% YP (Category 1)?	Is d<10% WT and L < 2 inches (Category 0)?	Move to Hydrotest / ILI Program (Category 2, 3 and 4)?	Type of Repair Made	Re-Assessment Interval	Comments

Integrity Engineer: *Compiled Data.*	
Signature:	Date:
Regional Corrosion Control Team Lead or Engineer: *Reviewed and Verified.*	
Signature:	Date:

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

QUESTIONS

Action 95282

QUESTIONS

Operator: MarkWest Energy West Texas Gas Company, L.L.C 1515 Arapahoe Street Denver, CO 80202	OGRID: 329252
	Action Number: 95282
	Action Type: [NGGS] NGGS Operations Plan (NGGS-OP)

QUESTIONS

Verification	
Does the operator own the selected facility	Yes
Is the selected facility a natural gas gathering system	Yes

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

ACKNOWLEDGMENTS

Action 95282

ACKNOWLEDGMENTS

Operator: MarkWest Energy West Texas Gas Company, L.L.C 1515 Arapahoe Street Denver, CO 80202	OGRID: 329252
	Action Number: 95282
	Action Type: [NGGS] NGGS Operations Plan (NGGS-OP)

ACKNOWLEDGMENTS

☑	I certify that, after reasonable inquiry, the statements in and attached to this Natural Gas Gathering System Operations Plan are true and correct to the best of my knowledge and acknowledge that a false statement may be subject to civil and criminal penalties under the Oil and Gas Act.