CRESTONE PEAK
RESOURCES

Integrity Management Plan

Crestone Peak Resources Midstream
Pipeline System

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The purpose of this Integrity Management Plan (IMP) is to specify regular inspection, monitoring and maintenance activities for pipelines in the Crestone Peak Resources Midstream, LLC (Company) system and briefly describe the basis thereof.

1 Scope

1.1 Equipment Scope

This IMP includes all buried cross-country pipelines in the Company pipeline system, which consists of NPS 12 trunk lines, NPS 4 and NPS 6 laterals, as well as NPS 8 intermediate lines. Appendix 1 lists included pipeline segments.

1.2 Activity Scope

The activity scope of this IMP includes inspection, monitoring and maintenance activities regularly occurring during the operation of the subject pipelines. These activities aim at obtaining information on the condition of the pipelines as well as the status and effectiveness of safeguards against pipeline integrity threats. The following activities are not considered part of this IMP:

- Factory acceptance testing
- Post-construction inspection and testing
- Inspections associated with repairs and modifications (e.g. weld X-ray)

1.3 Physical Boundaries

Activities specified in this IMP relate to equipment normally considered as part of pipelines. Pipelines interface with other equipment inside facilities, including well facilities, central delivery points and customer tie-in points. The physical demarcation between pipelines and other equipment is the meter skid, including pig traps, lateral pipe connections and taps up to and including the first isolation valve, if a pig trap is installed. If a pig trap is not installed, then the physical demarcation is the first in-line pipeline isolation valve inside the facility boundary.

Mid-field equipment, such as headers and ILVs are considered part of pipelines. Other equipment also part of the pipelines includes but are not necessarily limited to corrosion coupons, CP rectifiers, anode beds and test stations, and above ground valve stations.

2 Right of Way Surveillance Regulatory Requirements

2.1 Overview

This section summarizes those regulatory requirements that relate to the routine integrity management of pipelines in the Watkins field in Colorado, to ensure that these requirements are incorporated into the IMP. There are numerous federal and state agencies that administer regulations pertaining to the safety of pipelines in general, including but not necessarily limited to the following:

- Pipeline and Hazardous Materials Safety Administration, Department of Transportation (PHMSA/DOT)
- Environmental Protection Agency (EPA)
- Occupational Safety and Health Administration (OSHA)

- Corps of Engineers (USACE)
- Colorado Oil and Gas Conservation Commission (COGCC)
- Colorado Department of Public Health and Environment (CDPHE)
- Colorado Department of Labor, Oil & Public Safety (CDOL)
- Colorado Public Utilities Commission (COPUC)
- Colorado Department of Transportation (CDOT)
- Utility Notification Center of Colorado (Colorado 811)

The regulators that are the most pertinent to pipeline integrity are the PHMSA, COPUC, and CDPHE; therefore, the remainder of this section focuses on these.

From a regulatory standpoint, all Company-operated gas pipelines are considered non-regulated onshore gathering pipelines. Gas lines are under Colorado Public Utilities Commission regulation CCR 723-4-4952(d) as Type C gathering. These pipelines are commonly referred to as non-regulated and jurisdictional pipelines. This essentially means that, among other things, the integrity management-related provisions set out in the federal regulations (Title 49 CFR Part 192 and in 723-4 of the Colorado Public Utilities Commission (COPUC) *do not* apply. However, these pipelines fall under the jurisdiction of the Colorado Public Utilities Commission.

The classification of the entire Company pipeline system is reviewed every year by the Regulatory group to identify any pipeline that is no longer in its designated class. As the Watkins field further develops, i.e. more pipelines and more civil structures are built, there is always a possibility that the classification of certain pipelines may change. Therefore, the regulatory status of these pipelines may also change, and these pipelines may fall under the federal pipeline safety regulations.

2.2 Pipeline Integrity Management Rules for Non-Regulated Pipelines

There are no federal (DOT) or state (COPUC) rules at present time that affect the routine integrity management of non-regulated pipelines. Pipeline Integrity Management under the federal and state regulations only apply to transmission pipelines that could affect a High Consequence Area (HCA).

3 Stakeholders Involved in Routine Pipeline Integrity Management

While the IMP is administered by the Facilities Engineering team, the process of making and executing the plan involves a variety of stakeholders. Table 4-1 gives an overview of the key internal stakeholders serving core and supporting functions in relation to this IMP.

Note that the overview of stakeholders and functions in this section is limited to those stakeholders who are actively involved in executing this IMP and those functions that are directly related to this IMP. In other words, most stakeholders listed below have other pipeline integrity-related functions as part of the overall integrity management program.

Name of team	Typical pipeline IMP-related core functions
Operations / Facilities Engineering & Construction	• Producing, updating and implementing the pipeline IMP[1] • Managing the chemical contractor and the execution of the chemical treatment plan • Managing corrosion monitoring activities, such as coupons and sampling • Managing pipeline inspection and survey activities, such as specialized CP surveys, ILI and coating survey • Non-destructive examination of in-service pipelines and related equipment • Engineering pipeline integrity-related modifications and retrofits (e.g. valves, pig traps) • Responding to one call tickets raised prior to performing pipeline integrity work involving ground disturbance and locating existing pipelines
Operations	• Operating pipelines within the safe operating limits • Executing regular maintenance pigging and supporting ILI • Executing ROW surveillance • Performing Company-mandated inspections • Valve maintenance • Executing regular maintenance of pipeline integrity-related equipment, such as H_2S corrosion coupons and chemical injection systems • Performing regular CP survey and maintenance • Running paraffin program maintenance activities, including pigging • Creating work orders in E-Maintenance for regularly occurring pipeline integrity activities
Facilities Engineering & Construction / GIS / Regulatory	• Providing supervision for vendor-performed pipeline integrity activities in the ROW • Executing modifications, retrofits, excavations and pipeline repairs • Providing ongoing GIS data analysis support • Information management system development • Collecting pipeline as-built data for new builds and maintaining a pipeline register • Maintaining GIS database • Periodically reassessing the regulatory status of pipelines • Flow modeling for pipeline integrity applications
Supply Chain	• Making and managing contracts with pipeline integrity product suppliers and service providers
Surface Land	• Making landowner notifications prior to performing inspection, maintenance and repair in the pipeline ROW

Table 4-1 – Overview of key internal stakeholders in the core pipeline integrity management process

4 Activity Plan

For pipelines falling under the scope of this IMP, Appendix 4 contains the schedule of inspection, monitoring and maintenance activities. The latter part of the IMP provides more detailed information on these activities.

[1] Producing and updating the IMP involves a complete cycle of activities, including but not limited to managing pipeline data, identifying integrity hazards and assessing the risks arising from these hazards, defining effective control measures, assessing the results reported from IM activities, anomaly management and assessing the overall condition of pipelines.

5 Damage Mechanisms and Mitigation

5.1 Overview

For internal corrosion, external corrosion, third-party damage and blockage, this section briefly describes the relevant damage mechanisms, the mitigation in place and the relevant inspection, monitoring and maintenance activities. All probable expected damage mechanisms are included.

Mitigation includes design features and measures that reduce the adverse effects and/or the intensity of damage mechanisms. For any integrity threat, mitigation generally includes a combination of:

- Built-in mitigation that is an integral part of the pipeline and does not require human intervention or supervision to remain effective (e.g. corrosion allowance or external coating)
- Operational mitigation that requires human intervention or supervision to some degree, otherwise they become ineffective over time (e.g. chemical treatment or impressed current cathodic protection)
- Administrative procedures that define the routine practices (e.g. chemical treatment plan review)

Inspection and monitoring activities provide information on the condition of the pipelines and the mitigation effectiveness. Maintenance activities ensure the continued effectiveness of mitigation steps. The combination of regular inspection and monitoring is an effective means of keeping time dependent damage mechanisms, such as most forms of corrosion, under control. This does not generally apply to non-time dependent damage mechanisms, such as third-party damage, as the failure occurs randomly and because Company has limited control over the actions of third parties.

Table 6-1 contains a cross-reference between the various damage mechanisms and mitigation.

Mitigation	Internal corrosion	External corrosion	3rd party damage	Blockage
Corrosion allowance	Built-in	Built-in		
Fluid Separation	Operational			
Corrosion inhibition	Operational			
Biocide	Operational			
H_2S scavenging	Operational			
Maintenance pigging	Operational			Operational
Chemical treatment review	Admin			Admin
External coating		Built-in		
CP system		Operational		
Depth of burial			Built-in	
Line markings			Operational	
One call system (811)			Admin	
Corrosion Monitoring Coupons	Operational			

Table 6-1 – Overview of mitigations

5.2 Internal Corrosion

5.2.1 Description of Damage Mechanism

Internal corrosion can occur due to a variety of damage mechanisms.

CO_2 corrosion – Carbon dioxide (CO_2) normally occurs in the produced fluid in gas phase. When CO_2 and liquid water are present together in the pipeline, they form carbonic acid, which can cause severe pitting to carbon steel.

H_2S corrosion – Similarly to carbon dioxide, hydrogen sulfide (H_2S) naturally occurs in the produced fluid in gas phase. The presence of H_2S is associated with two different phenomena, one results in gradual wall loss and the other one results in cracking; however, the two are closely related. When H_2S and liquid water are present together in the pipeline, it causes pitting to carbon steels at relatively slow rates compared to CO_2 corrosion.

Microbiologically Influenced Corrosion (MIC) – Microorganisms naturally occur in the produced fluid and can tolerate and thrive in a variety of conditions (pressures, temperatures and chemistry) commonly occurring in gathering systems, if there is water present. The microorganisms produce byproducts such as acids that are corrosive to steel.

Galvanic corrosion – Iron sulfide can form a protective layer on steel, but when that layer is damaged, the exposed steel can experience accelerated corrosion.

5.2.2 Mitigation

There is a variety of built-in, operational and administrative mitigation steps in place across the Company pipeline system to combat the damaging effects of internal corrosion.

Corrosion allowance – Corrosion allowance is part of the wall thickness that is added over and above what is required for structural strength and is intended for being consumed by corrosion over the service life of the pipeline.

Fluid Separation – The produced fluid goes through multiple stages of separation as it makes its way from the well to the point of sale. The first stage of separation occurs at the wellsite facility; the second stage occurs at the Pony Station compression site (currently for gas only). While it is essentially commercially driven, the most significant benefit of separation from an integrity management point of view is that the free water is removed from the produced fluid (both liquid and gas). Free water plays a key role in all corrosion processes described in Section 5.2.1, and its removal greatly reduces the likelihood of internal corrosion.

Corrosion inhibitor treatment – The corrosion inhibitors used in the Company pipeline system are chemical additives that are designed to adhere to the pipe wall and form a physical barrier between the steel and the conveyed fluid. As the internal corrosion issues are largely associated with the presence of water, the corrosion inhibitor products are selected in such a way that they are carried in the fluid and treat the pipe through the water. The corrosion inhibitors also help control the solid deposition in the pipelines by dispersing the solids and removing already deposited solids. Corrosion inhibitor is currently batch applied to the main trunk lines every 6 months.

Biocide – Biocide is a chemical additive designed to mitigate the presence and proliferation of microbes within the gathering systems. It is applied every 6 months in conjunction with the application of Corrosion Inhibitor Treatment.

H_2S scavenger treatment– H_2S scavenger is a chemical additive that reacts with hydrogen sulfide and converts it into a more inert molecule. H_2S scavenger is injected into the compression inlet line before the gas separation vessel at Pony Station. This operation is designed to reduce the H_2S content of the gas to 4 ppm or less per gas sales contractual standards. Currently the gathering system is at a low risk of H_2S corrosion due to the low content of H_2S present in the Niobrara and the low pressure at which the wells and gathering system operate.

Maintenance pigging – The two main purposes of using maintenance pigging for internal corrosion control purposes are (1) removing liquids and solids accumulated in the pipeline and (2) batch chemical treatment. Pigging is very effective in removing liquids from pipelines, which significantly reduces the likelihood of internal corrosion of all types. Along with the liquids, pigs also remove solids from the pipeline (depending on the type of pig and the nature and adhesion of the solids to the pipe wall), the greatest benefit of which is reducing the environment favorable for microbial activity.

Periodic chemical review – Changes occur throughout the life cycle of the wells and surface facilities that require modifications to the chemical treatment programs. Periodic chemical reviews are scheduled to provide adequate oversight of the chemical programs. This process is continuous and led by the Chemical Program Manager.

5.2.3 Inspection, Monitoring and Maintenance Activities

Internal corrosion mitigation is accompanied by a variety of inspection, monitoring and maintenance activities. For scheduling information, refer to the activity plan in Appendix 44.

Corrosion coupons – Corrosion coupons are used for obtaining information on the general and average wall loss rate over time due to internal corrosion and any pitting corrosion that may have also occurred. Corrosion coupons (typically rod type) are installed at selected strategic locations on trunk lines. After retrieving the coupons, the general corrosion rate can be inferred from the coupons' weight loss and the pitting corrosion rate can be inferred from the microscopic inspection of the coupons' surface.

Sampling and sample analysis – Taking samples from the produced liquids and analyzing the samples provides valuable information on the corrosivity of the fluid in the pipeline as well as some indication of the corrosion mechanism through corrosion byproduct identification.

H_2S content monitoring – Samples are typically taken monthly at every well and are analyzed for H_2S content of the produced fluid. Data from the sampling is held by the Chemical Program Manager and historical data is available for analysis. The primary driver for H_2S sampling and analysis is the compliance with our customers' gas quality specifications and the continuous review of the H_2S scavenger treatment program.

CO_2 content monitoring – The CO_2 content for each well is noted on the gas analysis reports which are updated at intervals dictated by either the customer, regulation or COP internal standards. While rapid changes normally do not occur, the concentration of the CO_2 for a well may change over time and the CO_2 content in the lateral lines and trunk lines may also vary accordingly.

Flow velocity monitoring – In both gas and liquid pipelines, the ability of the gas phase as well as the less dense hydrocarbon liquid to keep any liquids in motion (i.e. sweeping effect) greatly depends on the flow velocity. If the flow velocity is very low, then the condensed or carried-over liquids accumulates in low spots, which may result in increased likelihood of internal corrosion and slugging. In certain pipelines, the flow velocity could be as low as 1 ft./s.

Dead leg identification – Dead leg pipelines are those that are either temporarily (e.g. less than 90 days) or permanently taken out of service but remain physically connected to another in-service pipeline or facility.

In-line inspection – In-line inspection is covered separately in Section 6.3.

5.3 External Corrosion

5.3.1 Description of Damage Mechanism

External corrosion can occur due to a variety of damage mechanisms

Low soil resistivity – Soils typically allow the movement of electric charge to some degree, some soil more so than others. Main factors influencing the soil resistivity include composition (ion content), particle size, compactness and moisture content. Generally, soils with greater than 10,000 Ωcm resistivity are essentially non-corrosive to carbon steel and soils less than 500 Ωcm are extremely corrosive to carbon steel. Some areas in the Niobrara (sedimentary rock along riverbeds) are known to have low soil resistivity. Low-resistance soils permit the flow of electric current, and if the pipeline is part of an electrical circuit as the anode, then corrosion may occur where the current leaves the pipe. Such current flow may be driven for example by the free corrosion potential of the pipe or induced by an external CP system or AC interference.

Microbiologically Influenced Corrosion – The soil surrounding the pipe is filled with various forms of life, including microbes. To thrive, microbes need water and nutrients, such as carbon, hydrogen, oxygen, nitrogen, sulfur, phosphorus, calcium, sodium, iron, magnesium and copper. The soil normally contains plenty of these resources, especially in cultivated farmland treated with fertilizers. Microbes do not attack the steel pipe directly but produce byproducts such as acids that are corrosive to steel.

CP interference – CP interference refers to the process of transfer of CP current between two close-by buried structures, such as a pipeline crossing involving a foreign and a COP-operated pipeline. From a COP pipeline standpoint, CP interference could occur in two ways: the CP current is discharged from the foreign pipeline and enters the COP pipeline and vice versa. There does not necessarily have to be damage to the external coating to allow the current to enter and exit. However, if there is a coating defect at the current discharge point, corrosion may occur, the rate of which depends on the current density[2]. Test stations are installed at all crossings to monitor any changes in potential.

AC interference – AC power lines generate a concentric alternating electro-magnetic field. If a conductor, such as a pipeline is placed in the electro-magnetic field in such a way that it crosses the magnetic flux lines, then alternating electrical current is induced in the pipeline (the conductor). Main factors governing the strength of the induced electric current include the distance between the power line and the pipeline, the AC voltage, the magnetic permeability of the air and soil, and the length of pipe exposed to the electro-magnetic field. AC interference may become a cause of external corrosion if the induced electrical current is discharged from the pipeline into the soil, at a coating defect for example, and thus turning the pipeline

[2] Example: If 0.01 A of direct current is continuously discharged from an 8" Schedule 40 steel pipe into the soil (electrolyte) through a 1" diameter coating defect, then complete wall loss could occur in less than two weeks.

into an anode. AC interference may also cause an unsafe touch potential. AC voltages >10 V are reviewed for corrective actions.

Atmospheric corrosion – The corrosivity of the atmosphere depends on several interacting and constantly varying factors (both spatially and temporally), such as weather conditions, air pollutants (e.g. sulfur dioxide, salts), temperature (air and pipe). The Niobrara field lies in an area of the United States where the intensity of atmospheric corrosion is low compared to other areas of the USA.

5.3.2 Mitigation

External coating – Coatings have a high dielectric strength, which prevents the transfer of ions between the steel pipe and its external environment. External coatings are the primary and most effective means of protection against external corrosion. In the Company pipeline system, the external coatings for underground service include fusion-bonded epoxy (FBE) for shop-coated straight pipe, two-part epoxy for field coated girth welds and fittings, and abrasion resistant overcoat for pipe installed in bore holes. For above ground service, a multi-layer coating system is used consisting of an epoxy base coat and a polyurethane topcoat. Soil-to-air transitions have a petrolatum tape wrap (Densyl tape) or Viscotaq over the FBE base coating.

CP system –An impressed current cathodic protection system is used to protect the buried pipelines from external corrosion. Deep anode beds are connected to the pipeline through a rectifier which converts AC power to DC power. The cathodic protection is effective if the instant-off pipe to soil potential[3] is at least 850 mV or at least 100 mV more negative than the free corrosion potential of the pipe relative to a copper/copper sulfate electrode.

5.3.3 Inspection, Monitoring and Maintenance Activities

CP survey – CP survey entails measuring the pipe to soil potential relative to a copper/copper sulfate electrode by connecting one lead of a voltmeter to the pipe and the other lead to a portable copper/copper sulfate electrode while the electrode is in contact with the soil. The connection to the pipe can be made at dedicated test points or at any points where electrical contact to the pipe can be established.

Close interval potential survey (CIPS) – CP surveys provide information on the status of the CP system and the protection level of the pipe only at the test points. A pipeline that is adequately protected at the test points is not necessarily adequately protected everywhere between the test points. The purpose of the close interval potential survey is to measure the pipe to soil potential at regular intervals, typically every 3 ft. ***Transformer rectifier monitoring and maintenance*** – The cathodic protection of pipelines is dependent on the functionality and the good performance of an extensive network of transformer rectifiers, which are regularly checked to ensure that the pipelines continue to receive adequate protection.

AC interference survey – AC interference survey is relevant to those pipelines that are installed in the right of way of three-phase high-voltage overhead power lines. AC interference readings may be conducted during the annual CP survey or in between surveys if the need arises.

In-line inspection – In-line inspection is covered separately in Section 6.3.

[3] The instant-off potential is the polarized half-cell potential of an electrode taken immediately after the cathodic protection current is switched off.

5.4 Third Party Damage

5.4.1 Description of Damage Mechanism

Third-party damage refers to a variety of damage forms caused by mechanical impact, mostly unintentional, during ground disturbance work not controlled or supervised by Company. By far the most common source of the damage is the use of a mechanical excavator to remove soil during the construction of pipelines and other utilities. However, certain farming activities (e.g. deep plowing) also have the potential to cause damage to the pipe, especially in areas impacted by soil erosion. Common factors leading to third party damage include inadequately marked pipelines, starting ground disturbance without making the one call and human error during excavation.

Third party damage could result in a variety of instantaneous and time-dependent defects:

- Coating damage, which could ultimately result in external corrosion over time
- Gouge that could result in cracking and fatigue failure over time
- Dent that creates a pipe bore restriction and could also result in cracking and fatigue failure over time
- Overstress and instantaneous failure

The above damage may not only occur in isolation but in almost any combination. It should be noted that while third party damage is one of the leading causes of pipeline failures, unlike internal and external corrosion, third party damage cases are unrelated, isolated and localized, mostly dominated by factors over which the operator does not have control.

5.4.2 Mitigation

Depth of burial – Sufficient depth of cover protects the pipeline from damage that may result from common farming activities and other types of work where the ground disturbance is limited to cultivation level. All Company pipelines are originally installed to a depth that results in 4+ feet of cover.

Line markings – Line markers consist of a combination of high-visibility above ground signs installed at regular distances along the route of the pipeline and buried warning tapes installed above the pipeline for its full length. The purpose of the line markers is twofold: (1) they indicate the approximate location of the pipeline and thus give warning to anyone intending to perform ground disturbance, and (2) the above ground markers carry information about the conveyed fluid, the name of pipeline operator and its contact telephone number, which can be called before commencing ground disturbance. Line markers will be replaced when found during regular pipeline ROW reviews.

One-call system (811) – The one-call system is a damage prevention notification system designed to provide excavators with the capability of making only "one call" prior to excavation, whereby all utility companies (except water and sewer) with underground lines in the area receive notification of the planned excavation. The utility operator is then required to physically locate and mark the location of their underground lines to help the excavator avoid accidental damage. The underground pipeline damage prevention program for Colorado is regulated in CRS Title 9 1.5. One-call notifications can be made online (http://colorado811.org/) or via telephone (811). All CPRM pipelines are registered with Colorado 811.

5.4.3 Inspection, Monitoring and Maintenance Activities

There is almost no way to predict or prevent the occurrence of third-party damage. However, there are a few ways to identify the signs of third-party damage that has already occurred.

Right of way surveillance – Right of way surveillance entails visually observing the pipeline right of way on a regular basis and checking for signs of ongoing and past unreported third-party activities and leaks as well as the general condition of the ROW. When ground surveillance is performed then the condition of above ground line markers is also checked (and damaged markers are restored or replaced if needed), and a gas detector is used to enhance the leak detection.

Depth of cover survey – All Company pipelines are laid to a depth that provides 4+ feet of cover on top of the pipe. As the soils across the Niobrara field are not typically susceptible to significant erosion, there is no need for regular depth of cover surveys. However, gradual soil erosion may occur either due to environmental effects and events, such as flooding, or farming activities in certain areas. When the right of way surveillance highlights an area where soil erosion may have occurred, a depth of cover survey is performed if deemed necessary to confirm that the pipeline is sufficiently protected from third party damage.

In-line inspection – In-line inspection is covered separately in Section 6.3.

5.5 Blockage

5.5.1 Threat Description

Blockage means reduction of the pipeline bore to an extent that the throughput of the pipeline is significantly reduced (up to and including full blockage) or the passage of pigs is prevented. The first obvious operational sign of blockage is typically the increased backpressure adversely affecting the operation of the wells and separators and ultimately triggering the high-pressure alarm and causing shut-down. Blockage is primarily a flow assurance issue; it adversely affects production and it typically does not have direct safety or environmental consequences.

5.5.2 Mitigation

Paraffin Management Program – As the Watkins field transitioned from a few appraisal wells to approximately 78 producing wells, paraffin has proven to be a systemic issue. The initial steps to paraffin management include a wide variety of tools and techniques including but not limited to lab analysis of the wax-forming properties of the produced crude oil, trials of continuous injection of paraffin chemicals and batch treatments, hot water and hot oil treatment, and maintenance pigging. The approach to paraffin mitigation is expected to evolve and adapt to changing conditions with the continued development of the Watkins field.

Hydrate Management – Natural gas hydrates are solid compounds of methane trapped within a crystalline water structure and are generally formed when liquid water is condensed in the presence of methane at high pressure. Once formed hydrates can block pipeline and processing equipment. While it would be very rare for hydrates to form in CPRM pipelines due to the low operating pressure, if hydrates do form, CPRM's hydrate removal procedure will be followed.

Periodic chemical review – Chemical reviews are conducted by the Chemical Program Manager to oversee the chemical treatment program and to make sure that the types and amounts of paraffin and/or hydrate mitigation chemicals deliver the desired results.

6 Pigging

6.1 Pig Traps

All trunk lines, and some lateral lines in the Company pipeline system were designed and built to allow passage of pigs; however, not all of them currently have pig launchers and receivers. Appendix 2 contains information on the current pig trap status of each trunk line.

Currently conventional launchers and receivers are the only style of pig traps used in the Company pipeline system.

Any excess liquid in the pig trap barrel can be drained to an on-skid sump. This procedure is detailed in the pigging standard operating procedures.

6.2 Maintenance Pigging

Maintenance pigging is a very effective internal corrosion management tool. The two main areas of use include removing substances from the pipeline that may give rise to corrosion (e.g. free water, solids and microbes) and to batch treat the pipeline with chemicals (e.g. corrosion inhibitor and biocide).

Maintenance pigging is currently performed periodically as needed on all trunk lines. As the gathering system expands or conditions change, the maintenance pigging plan may change.

6.3 In-line inspection

6.3.1 Overview

Of all inspection methods, in-line inspection (smart pigging) provides the most comprehensive evaluation of pipeline integrity and damage along the entire length of the pipeline. All trunk lines were designed to accommodate smart pigs; and all of them have permanent launchers and receivers installed.

7 Leak Detection

7.1 Detection of Small Leaks

No dedicated instrumented leak detection system is currently installed for the Company pipeline system that is capable of automatically detecting small leaks. Small leaks are those that do not result in distinctive pressure drop detectable by the low-pressure alarm cause and effect logic in the SCADA system. This is the typical failure mode for corrosion pinhole defects, flange gaskets and volumetric weld defects. The detection of such leaks is currently based on regular ROW surveillance and external notifications made by the public, landowners or contractors working in the area.

This type of leak detection is discrete, opportunistic and relies on observing the direct physical manifestations of the presence of the leak, such as hydrocarbon odors, gas detectors going off and hissing sound. A FLIR camera is used to assist in detecting such leaks.

7.2 Detection of Ruptures

The detection of pipeline ruptures is based on the pressure monitoring and low-pressure alarms. The pressure in the system is monitored at every facility, including but not limited to the discharge of flowlines, separators and VRUs at the wellsite facilities and at the inlet and discharge of separators and compressors at Pony Station.

8 Pipeline Isolation

8.1 Overview

Pipeline isolation valves are important safety devices in the event of a leak or other pipeline emergency. Pipeline isolation valves also play a key role in certain operational activities, such as increasing the flow velocity for pre-pigging liquid sweeping purposes in gas pipelines.

Most pipeline isolation valves are manually operated valves and check valves; Appendix 2 gives an overview of locations where these valves are installed.

Most isolation valves are not in regular use for operational purposes; therefore, regular testing is used to verify their functionality and operability. While a leak test is the ultimate proof of a valve's ability to isolate pressure, it is generally impractical to perform leak tests for the following reasons: (1) the valve and pipeline configuration generally do not allow for measuring the pressure buildup in a small depressurized volume downstream of the valve, (2) there are no performance standards against which the results of any leak test could be assessed, and (3) leak tests disrupt production for the entire duration of the test. Therefore, the Company pipeline isolation valve testing regime is based on a combination of partial and full closure tests. Closure tests are limited to confirming the actuation of the valves without checking the integrity of the valve seat seals.

8.2 Remotely Controlled Isolation Valves

The primary purpose of remotely controlled isolation valves is to minimize the environmental and safety effects if Pony Station experiences a sudden pressure drop, fire, or other upset condition. Remotely controlled pipeline isolation valves are installed on the inlet and discharge of Pony Station. The discharge has one on both the gas and fluid lines.

- Pony Station – Inlet and discharge header to station equipped with emergency shutdown systems (ESDs).
- Well sites – Each well site facility is equipped with an ESD system and can be shut down remotely.

An oxygen (O_2) analyzer is installed at the sales meter run at each wellsite facility and the Pony Station and is set to not let the O_2 level exceed contractual limits.

8.3 Manual Isolation Valves

Manual isolation valves are necessary to those operational, maintenance and repair activities that rely isolating sources of pressure, re-routing the flow, installing pig trap isolation valves and repairing pipeline leaks. Manual isolation valves are incorporated into each pipeline at the departing header and at the facility inlet or tie-in header. For trunk lines, manual block valves are also installed in strategic mid-field locations either in an in-line or in a header configuration. Appendix 2 gives an overview of locations where these valves are installed.

8.4 Check Valves

Check valves are incorporated into each flowline to prevent backflow in the event of a catastrophic failure and the leak being fed by the downstream central facility and trunk line, and thus to limit the release size to the inventory of the failed pipeline. Check valves are installed at the Pony Station inlet header, inboard of the pipeline isolation valve downstream of the pig receivers. Note that although check valves are installed throughout the production and gathering system at other locations, this section only considers those protecting the pipelines.

8.5 Valve Testing

In addition to the maintenance activities specified in the valve manufacturers' recommended operation and maintenance manual, manually operated and remotely controlled valves are subject to regular testing. The valve testing regime is described in Appendix 44.

Regular valve testing normally entails cycling the valve back and forth once between fully open and fully closed position. While this is the desired testing method, it is permissible to perform a partial closure test if the adverse production impact of a full closure test is excessive. Cycling of valves as part of routine and planned operations may count toward testing if the valve operation is properly documented as a test. Testing of valve seat seal leakage is not regularly performed.

Appendix 1 List of Pipeline Segments

#	Line Name	Type	Pipeline description	Comment
1	Spine A	Trunk line	Spine A – North-South running trunk line originating at Tebo 4-1H and terminating at Pony Station	
2	Spine G South	Trunk line	South Spine G – North-South running Line originating at the State La Plata and terminating at the Line 6 tie-in	
3	Line 6	Trunk line	Line 6 – East-West running line Originating at the Eastern Hills Tie-in and terminating at the tie-in to Spine A.	
4	Spine G North	Trunk line	North Spine G – North-South running line originating at the termination point of South Spine G and terminating at the Line 7 interconnect.	
5	Line 7	Trunk line	Line 7 – East-West running line originating at the North Spine G tie-in and terminating at Pony Station	
6	Aspen Line	Trunk line	Aspen – North-South line originating at the Aspen well location and terminating at Line 7 tie in.	

Appendix 2 Pipeline Valve/Trap Locations

Pipeline type	Upstream end valve location	Midline valve location	Downstream end valve location
Lateral line	Gas Sales Meter Departing Well Location Pig Launcher (if in place)	None	Trunk line tie-in point (dog leg) Pig Receiver (if in place)
Trunk line	Aspen - Pig Launcher	None	Aspen - Pig Receiver
	Spine G North – Pig Launcher	#1 Spine G North Mainline Valve	Spine G North – Pig Receiver
		#2 Spine G North Mainline Valve	
		#3 Spine G North Mainline Valve	
		#4 Spine G North Mainline Valve	
		#5 Spine G North Mainline Valve	
		#6 Spine G North Mainline Valve	
		#7 Spine G North Mainline Valve	
	Line 7 – Pig Launcher	Line 7 Mainline Valve	Line 7 – Pig Receiver
	Spine G South – Pig Launcher	#1 Spine G South Mainline Valve	Spine G South – Pig Receiver
		#2 Spine G South Mainline Valve	
	Line 6 – Pig Launcher	#1 Line - 6 Mainline Valve	Line 6 – Pig Receiver
		#2 Line - 6 Mainline Valve	
		#3 Line - 6 Mainline Valve	
		#4 Line - 6 Mainline Valve	
	Spine A – Pig Launcher	#1 Spine A North Mainline Valve	Spine A – Pig Receiver
		#2 Spine A North Mainline Valve	
		#1 Spine A South Mainline Valve	
		#2 Spine A South Mainline Valve	
		#3 Spine A South Mainline Valve	
		#4 Spine A South Mainline Valve	

Appendix 3 List of Significant Pipeline Events

This appendix contains a summary of significant pipeline events, including incidents, major modifications and repairs in chronological order.

Pipeline description	Event type	Event date	IMPACT ID#	Event description
Vehicle struck pig receiver	Strike	11/24/2016	259668	Driver lost control of vehicle, ran off public road and struck the pig receiver, damaging valve gear actuator, but no loss of containment.

Examples of events to include:

- Line leak, rupture, strike
- Post ILI excavations
- Isolation valve replacements

Appendix 4 Activity Plan

A4.1 Regular External Corrosion Management Activities

Activity	Pipeline and equipment description	Location and extent of activity	Schedule	Responsible	Comment
Pipe to soil "ON" potential readings	• Trunk lines • Sales pipelines • Lateral lines	At each CP test point (includes permanent test stations at regular intervals and crossings, above ground accessible sections at pipeline start, end, valve stations and midfield headers)	Annually	Operations	
CP test station visual inspection and maintenance	• Trunk lines • Sales pipelines • Lateral lines	At each permanent CP test station including checking any permanent reference electrode installed at the test station	Annually	Operations	The visual inspection and maintenance of CP test points is preferably carried out in conjunction with the pipe to soil "ON" potential readings
Pipe to soil instant "OFF" potential readings	Trunk lines	At each CP test point	Annually	Operations	The pipe to soil instant "OFF" potential readings are preferably carried out in conjunction with the pipe to soil "ON" potential readings
Insulating flange visual inspection and electrical testing	All pipelines	At each insulating flange	Annually	Operations	Preferably done with every annual pipe to soil potential survey
Rectifier performance check	All rectifiers	Through the Remote Monitoring Units (RMUs) or at the rectifiers as applicable	Bi-Monthly	Operations	System on Bullhorns for remote monitoring.
Rectifier visual inspection, electrical testing and maintenance	All rectifiers	At each rectifier	Annually	Operations	Includes calibration check of panel meters and permanent reference electrodes
Visual inspection of above ground pipe and equipment	• Trunk lines • Sales pipelines • Lateral lines	Pig traps, headers, risers, in-line valves and air to soil interfaces	Annually	Operations	
AC Mitigation readings	• Line 6 Trunkline	Eastern Hills to Grande 12" pipeline	Annually	Operations	Conducted in conjunction with Annual CP survey

A4.2 External Corrosion Management Activities

Activity	Pipeline and equipment description	Location and extent of activity	Schedule	Responsible	Comment
CP interference survey	Pipelines whose cathodic protection is adversely affected by a foreign CP system	Location to be selected	As soon as reasonably possible after the possibility of CP interference has been identified	Operations	Pipelines that may be affected by a foreign CP system are identified from the regular CP surveys
Close interval potential survey (CIPS)	Pipelines for which the routine CP survey identifies areas of concern	Location to be selected	As determined by a CP specialist	Operations/ Facilities Engineering	The need for CIPS is determined by the CP specialist based on the assessment of other CP data

A4.3 Regular Internal Corrosion Management Activities

Activity	Scope of activity	Schedule	Responsible	Comment
Corrosion coupon retrieval and assessment	Wherever the coupons are located a retrieval and inspection will occur per the schedule.	Initially every 3 months, thereafter every 6 months, adjusted after every coupon pull depending on the previous corrosion rate.	Operations/Facilities Engineering	The complete list of corrosion coupon locations and the results from the coupon retrieval and assessment are held in a spreadsheet maintained by the Chemical Program Manager.
H_2S content monitoring	For every trunk line based on H_2S composition data from sampling at the wellhead riser	As needed	Operations	The driver for the sampling is contract specification and optimization of H_2S scavenger application
CO_2 content monitoring	For all gas pipelines based on CO_2 data from sampling at the wellhead riser	As needed	Operations/Facilities Engineering	The CO_2 content of the gas is reported as part of the yearly gas analysis for every well. The CO_2 data is cross-referenced with coupon data by the Chemical Program Manager / Facilities Engineering to identify internal corrosion trends.
Microbial enumeration	Wherever coupons are located or when fluid samples are collected for characterization	As needed	Operations	The driver for sampling frequencies is determined by both elevated counts and coupon inspection data.
Maintenance pigging	Gas trunk lines	Monthly	Operations	Maintenance pigging has been established to occur every ~30 days to properly manage liquid buildup in the gas trunk lines. Pigging interval may change based on results.
Ultrasonic wall thickness testing and internal visual inspection	All pig traps	Every 7 years	Operations/Facilities Engineering	The list of pig traps where routine ultrasonic wall thickness testing is performed are kept and maintained by Facilities Engineering.

A4.4 Ad-hoc Internal Corrosion Management Activities

Activity	Scope of activity	Schedule	Responsible	Comment
Sampling and sample analysis	As defined by the Chemical Program Manager and Facilities Engineering	As required	Operations/ Facilities Engineering	No routine sampling is currently taking place for corrosion management purposes. The sampling program for MIC and corrosion inhibitor residuals is currently under development by the Chemical Program Manager (Currently under discussion).
Flow velocity monitoring	For every pipeline using production rates	As required following an initial review	Facilities Engineering	There is a need for an initial review to identify pipelines with low flow velocity, thereafter this activity needs to be repeated when a pipeline’s throughput changes significantly
Dead leg register update	Identify pipelines taken out of service temporarily or permanently and not positively isolated from an in-service trunk line and include in the dead leg register	Based on notification	GIS / Facilities Engineering	A list of dead leg pipelines is maintained by the GIS Team and Facilities Engineering. Until such time a formal process for the identification of dead leg pipelines has been developed and implemented, the primary means of identifying dead legs is informal notifications from field-based personnel.
Non-destructive testing (ultrasonic wall thickness testing, radiography, thermography or other suitable means)	Selected above ground locations (risers and headers)	As required	Operations/ Facilities Engineering	The need for ad-hoc NDT for internal corrosion and flow-related issues is determined by the Chemical Program Manager based on coupon readings, sampling results or other sources indicating the possibility of unexpected or accelerated internal corrosion

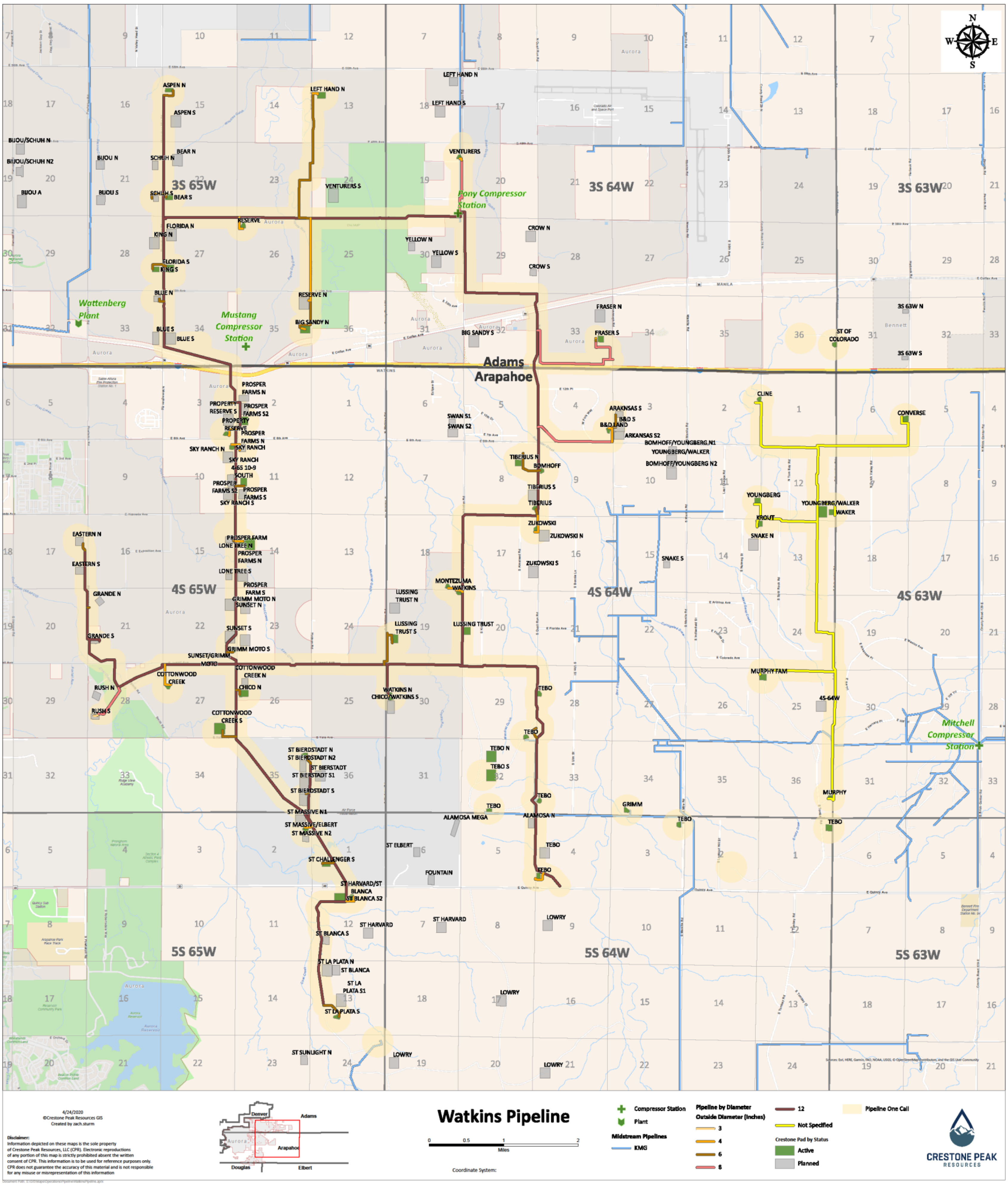
A4.5 Other Regular Activities

Activity	Pipeline and equipment description	Location and extent of activity	Schedule	Responsible	Comment
Right of way surveillance	• Trunk lines • Lateral lines • Sales lines	Full length	Monthly	Operations	Pipelines are inspected monthly and PM's are established for the main trunk lines
	Major road crossings	Crossing area	Monthly	Operations	All lines are inspected monthly.
Visual inspection and maintenance of valves	Main pipeline isolation valves (inlet and outlet), pig trap isolation valves and mid-line isolation valves in trunk lines	At each valve	Annually	Operations	A yearly PM is established for valve greasing and operation of all valves.
Regulatory status review	All pipelines	Full length	Annually	Regulatory	Part of the annual jurisdictional study

A4.6 Other Ad-hoc Activities

Activity	Pipeline and equipment description	Location and extent of activity	Schedule	Responsible	Comment
Depth of cover survey	Pipelines subject to activities or natural phenomena that may give rise to soil erosion	Areas affected by soil erosion	As required	Operations	Areas affected by soil erosion and therefore the need for depth of cover survey will be identified from the regular ROW surveillance
In-line inspection	Pipelines constructed with pigging facilities	Full length	Every 10 years	Operations/ Engineering	Each pipeline to be inspected with an ILI or direct assessment on a 10-year interval based on construction date. This will only affect pipelines under DOT jurisdiction.

Appendix 5 Company pipeline System Map



Appendix 6 Hazop Study

The Hazop Study is included as a separate document.

Revision Log			
Revision No.	**Date**	**Action**	**Reviewed By**
0	4/27/2020	Issued for Use	T.Brey
1	6/23/2020	Included Hazop Study Recommendations	T.Brey