ARPEL Reference Manual for Pipelines Integrity Management

2nd Edition - 2015

REGIONAL ASSOCIATION OF OIL, GAS AND BIOFUELS SECTOR COMPANIES IN LATIN AMERICA AND THE CARIBBEAN

ARPEL Reference Manual for Pipelines Integrity Management

2nd edition

Pipelines and Terminals Committee

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1. Introduction and Purpose

The integrity of an equipment or facility is its ability to perform the function for which it was designed safely and reliably, without affecting the security of people or the environment. Pipeline integrity management is a set of coordinated actions whose objective is to maintain the performance of a pipeline and its facilities as they were designed during their useful life, while efficiently managing the risks related to potential threats and the consequences of any failure as regards the environment, health, safety, corporate image, customers, economic losses and physical security, within the social responsibility, health, safety and environmental policies of the operating companies.

This document was developed to provide a general guideline to ARPEL Member Companies and other oil and gas sector operators so that they may check their own management and/or apply the best practices to ensure the integrity of gas, liquid hydrocarbon and biofuel pipelines in order to achieve excellence in its socially and environmentally responsible operational management. The guidelines and practices established in this document are indicative and not mandatory. This document does not reflect the legal requirements of specific jurisdictions. The companies shall be aware of the corresponding requirements applicable to their respective jurisdictions.

This Manual is accompanied by an Excel™ file with checklists for identification of pipeline baseline and for each threat (internal corrosion, external corrosion, third-party actions, forces of nature and operational errors) with the purpose of facilitating the review and compilation of the information required to support the assessment of the probability and consequences of failure during the risk analysis exercise. Although these checklists are described in this Manual, the electronic file allows the user to print it for fieldwork purposes as well as to include comments and to distribute it electronically among the professionals responsible for the integrity program of the company.

This Manual is used as a base tool for courses promoted by ARPEL and its Member Companies in order to expand the knowledge base and training of experts among their technicians and professionals.

2. Scope

This Manual provides ARPEL Member Companies with a set of referential instructions and procedures that may be modified to adapt them to the specific situation of each company and to the applicable legal or corporate regulations. The Manual:

- Covers the main issues to be included in a pipeline integrity management program
- Includes underground, submarine and aerial operating pipelines, as well as internal segments to production fields, refineries or terminals, even if the specific characteristics of these segments require additional considerations beyond the recommendations of this Manual
- Is a reference to study the basic elements recommended to be included in an integrity plan, without limiting the degree of deepness and development required in each particular case
- Analyzes thoroughly the failure modes and risk assessment and management, with a priority on prevention within the problems to be faced in order to ensure the continuous and safe operation of the pipelines
- Provides elements for management indicators to companies, which allow them to evaluate their pipeline integrity programs, and
- Provides the main reference regulations and bibliography to develop a pipeline integrity plan

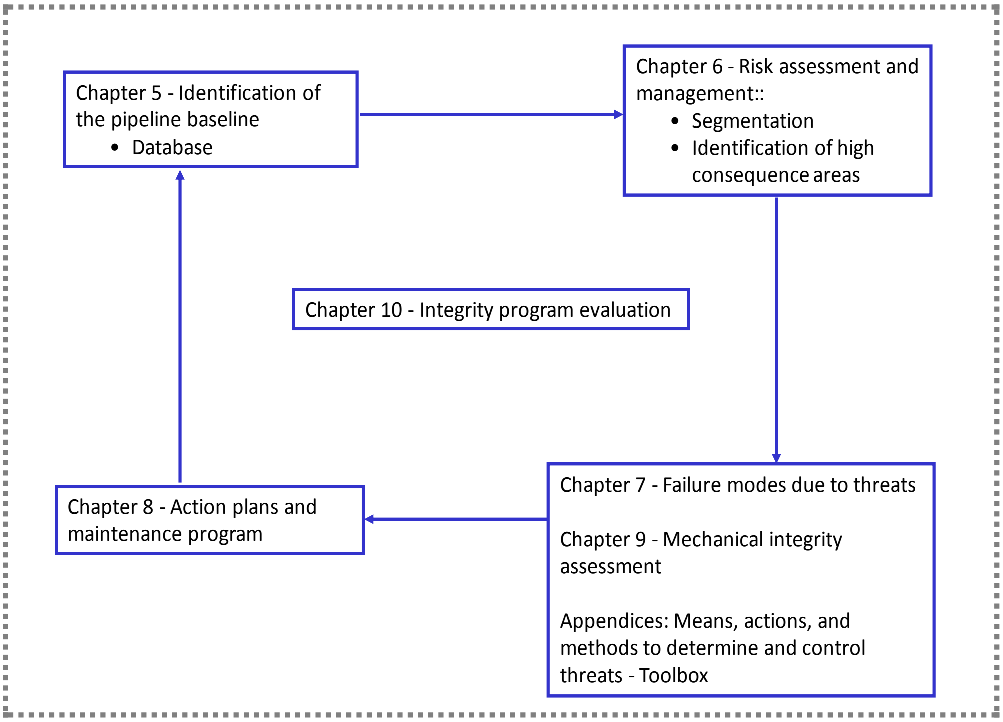


Figure 1: Basic elements of ARPEL Integrity Management Plan

This Manual covers the following elements of an integrity plan:

1. Identification of pipeline baseline: characterization, design and construction of the pipeline, signaling and georeferencing, and history of maintenance and inspection

2. Risk assessment and management:
   - Risk levels
   - Pipeline segmentation
   - Threats (probability of failure)
   - Consequences (population, environment, economy, image and external and internal clients)
   - Mitigation (minimum required to mitigate a risk, plan of action in high consequence areas - environment, populations, water bodies or others - and sensitivity maps)

3. Failure mode:
   - Total failure or rupture
   - Partial failure or leakage

4. Failure mechanisms due to threats:
   - By internal corrosion
   - By external corrosion
   - By forces of nature
   - By third-party actions
   - By operational errors
   - By fatigue

5. Integrity program evaluation:
   - Indicators
   - Audits
   - Continuous improvement

ARPEL has adopted a model of the Integral Environment, Health and Safety Management System (SIGAS&SI). It helps as a reference for companies to adopt it or adapt it according to the management system they use to develop their business efficiently. The SIGAS&SI is also the framework of the integrity management elements described in this Manual (see Figure 2).

Figure 2: Integral Environment, Health and Safety Management System (SIGAS&SI) – The system has three components (human factor, methods and facilities) and 18 elements.

This Manual focuses mostly on the application of best practices regarding element 17 (mechanic integrity) to apply to the additional pipelines and facilities composing the fixed and permanent facilities of the pipelines transportation system according to Figure 3[1], in order to forecast, minimize or avoid in a timely manner any hazardous condition and consequent undesired event in the operation of these systems:

a) Between the gathering pipeline of an exploitation concession plant and the oil treatment plant outside it
b) Between the crude oil treatment plant and the tank farm
c) Between tank farms
d) From refineries to distribution terminals
e) Between pumping stations
f) From the tank yard at the terminal to the oil buoy or to loading and unloading piers, or
g) Other points of product distribution and receipt

Consequently, the facilities within the scope of this Manual are the following:

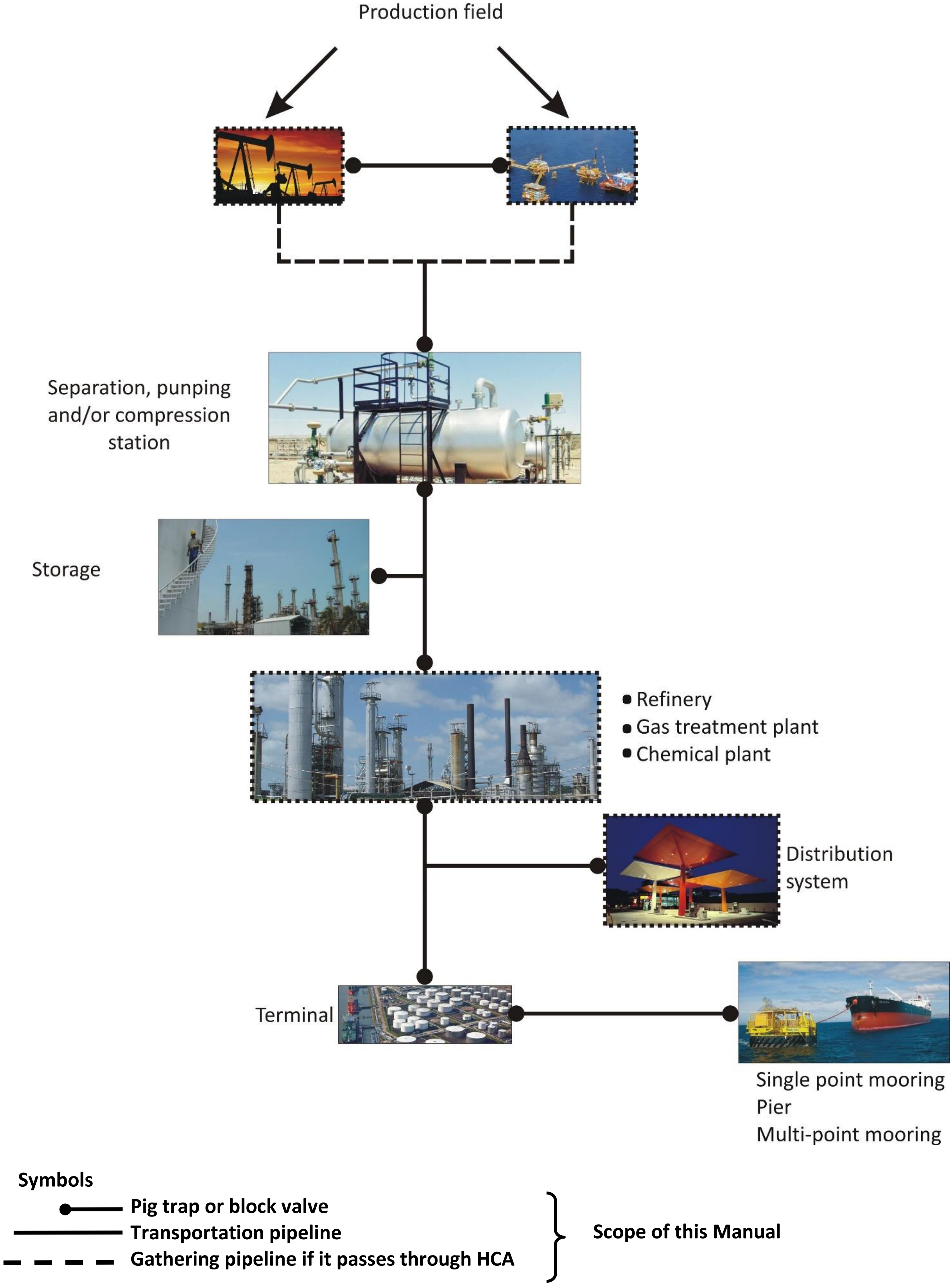
a) Main pipeline among pipeline terminals (marine, railroad and trucks), pumping stations, pressure reduction stations and measuring stations, including scraper traps and testing loops
b) Interconnection pipelines between storage tanks and shipping tanks for pipeline operation
c) Submarine pipelines connected to piers, buoy charts or single point mooring buoys
d) Capturing pipelines – transportation of untreated liquid hydrocarbons, outside commercial specifications – beyond the boundaries of exploitation concessions

This manual does NOT include the following facilities:

a) Auxiliary pipelines, such as water, air, vapor, lub oil and fuel gas pipelines
b) Pressure containers, heat exchangers, pumps, meters and other auxiliary circuit equipment
c) Pipelines designed for internal pressure:
    - Below 15 psi (1 bar), regardless of temperature
    - Above 15 psi (1 bar) if the design temperature is below –30°C (-22°F) or above 120° C (248°F)
d) Pipes or pipelines used in oil wells, mounting of wellheads, gathering pipelines (except if they pass through HCA), oil and gas separators, oil production tanks, or other production facilities and interconnection pipelines of such facilities inside the area of the exploitation concession
e) Internal pipelines of crude oil treatment plants, storage plants, gas and gasoline processing plants and petroleum refineries
f) Pipelines for distribution of natural gas
g) Internal pipelines for refinery operations
h) Submarine pipelines of offshore facilities other than those included in item c) of the scope of this Manual.

[1] The document will be periodically reviewed by ARPEL Member Companies. Besides, there are other important elements to manage pipeline integrity that are not discussed in detail in this document.

Figure 3: Scope of the Manual



3. Background

The oil industry operates equipment and products entailing certain risk due to their nature and characteristics. One of its multiple operations is fuel transportation through pipelines and internal distribution lines. This operation shall comply with technical and legal requirements which are increasingly stricter in the world. Failure to comply with such requirements may affect the assets of the companies, the environment and the communities related to the facilities, either those close to them or those depending on the supply. Therefore, the operational safety of these systems is crucial.

Environmental care is a key concern for ARPEL Member Companies, both regarding the countries and locations where they develop their activities and the rest of the world, as set forth in the Statement of Commitments of ARPEL (2005), the Reaffirmation of Commitments of ARPEL (2015), and in their own social responsibility, health, safety and environmental policies. Furthermore, one of the priorities of the companies is to further the improvement in the quality of life of the population, preventing pollution and developing the activities of the oil and gas sector with the lowest possible adverse effect.

The efficient work in each activity field requires care for the assets of the companies and the optimization of their facilities. This gives rise to the need to establish a common work basis which allows ARPEL Member Companies to apply the best practices for pipeline integrity management in order to achieve excellence in the socially and environmentally responsible operational management of their assets.

ARPEL Member Companies have already made important progress to establish pipeline integrity plans and have agreed to develop this Manual for Pipeline Integrity Management in accordance with their responsibilities. This Manual will contribute to establishing common criteria and to exchanging valuable experiences to support the operational, environmental and social excellence of pipeline operations, as well as to strengthen their bonds.

4. Glossary of Terms

A

ACVG
Alternating Current Voltage Gradient - Technique to identify major or small defects in the coating of a pipeline section.

Adjacent location
Contiguous properties or physical structures which in some cases share a common space.

Aerial / buried pipeline interface
In this context, it is the section of pipes in the pipeline that changes from surface or aerial to buried or submerged, and vice versa, where the susceptibility to damage by corrosion due to differential aeration is high.

Anode
Metal surface from which the current flows out of the metal into the solution, i.e., the area where metal corrosion or dissolution takes place.

Anode bed
Anodic system of several sacrifice anodes which are placed according to the quantity, depth and diameter required by design specifications.

Anthropic
Actions, events and physical structures carried out by man, which to some extent alter or modify the natural conditions of the landscape and the earth surface.

Arc burn
Indentation or tear of metal produced on the pipeline surface by dragging the electrode or due to the perforation of the bevel root in the electric arc welding process.

Assembly
Structural component manufactured through welding and/or flanged from pipes and pipeline accessories.

B

Bank or talus slope
Mass of detritus or rocky fragments at the base of a hillside.

Baseline
For purposes of this Manual, this term refers to the initial information available on the characteristics of the pipeline, its condition and the condition of the systems to control the different threats and mitigation of consequences. It involves information on its design, construction, maintenance and operation. This information is the basis for the initial risk assessment exercise in each segment of the pipeline.

BSCB
Balanced Scorecard - Used to follow up compliance with action plans for risk mitigation through indicators.

Bathymetry or bathymetric method
Implies survey and graph-drafting of the channel of a water current, river, lake or seabed using conventional topography methods and instruments that may be combined with the use of echosounding equipment in deeper waters.

Bypass
Bypass conduit.

C

Carstic erosion
Erosion produced by indirect dissolution of the calcium carbonate in calcareous rocks due to the action of slightly acid water. The water acidifies when its carbon dioxide content is high, for example, when it runs through a certain soil and reacts to carbonate forming bicarbonate, which is soluble.

Cathode
Metal surface where the current flows out of the solution and into the metal. There is no metal dissolution at the cathode.

Cathodic protection
Technique for protection against corrosion whereby the metal is converted to protect the cathode of an electrochemical cell. Cathodic protection is achieved through galvanic anodes or impressed current system to protect metal structures, such as equipment or pipelines buried or submerged in watersheds against corrosion.

Check valve
Device installed in the pipeline to block only one way of the flow of the product transported to any system section. The block valve enables total blocking of flow in both ways.

CIPS
Close Interval Potential Survey - Measurement of the potential at close intervals. Technique used to measure the potential of a buried pipeline, with the purpose of verifying the performance of the cathodic protection system.

Consequence of failure
Impact on the functions of a system (pipeline or plant). It can be classified according to the following categories: people safety, impact on the environment or the corporate image, and economic loss.

Consignment
Delivery of part of a pipeline or its equipment by the Operating Sector to the Maintenance Sector for the latter's intervention in order to ensure conditions that guarantee the absence of risks to health, safety and/or the environment, and preserve pipeline integrity. Example: control of absence of liquids/gases, denergization, independence of pipeline from operating lines, temporary modification of operational procedures, etc. (See "Deconsignment").

Corrective maintenance
Planned or unplanned actions or works to repair damage or failures in a pipeline with the direct purpose of restoring its operation after a rupture.

Corrosion
Electrochemical process through which the refined metals tend to form thermodynamically stable compounds (oxides, hydroxides, etc.) due to the interaction with the environment.

Corrosion rate
Estimated percentage of metal loss for a structure exposed to a corrosive medium during certain period of time.

CPR
Cathodic Protection Rectifier - Consists of an AC-DC current rectifier, an anode bed, a connection to the structure to be protected, and a transformer or generator.

D

DCVG
Direct Current Voltage Gradient - Technique to assess the status of buried pipelines coating. In cathodic protection systems, when the current flows through a steel-resisting soil exposed in the protective coating imperfections, a voltage gradient is generated in the soil. The greater the defect, the higher the current flow, and therefore, the voltage gradient. This is used as a prioritization technique when repairing defects. The voltage gradient is checked by measuring the difference between two reference electrodes with a specifically designed mili-voltimeter.

When both electrodes are 1.5 m away in the ground of a gradient produced by a defect in the coating, one of the electrodes adopts a more positive voltage than the other. This allows knowing the direction of the current flow and, therefore, locating the defect.

In order to simplify the interpretation of the defect location, the cathodic protection applied is separated from other direct current influences, such as telluric movements, direct current tractions, etc., through an *On/Off* switch for cathodic protection with asymmetric temporary response. This direct current switch may come from the cathodic protection system of the pipeline or from an independent direct current source, such as a portable generator or batteries using a temporary anodic bed transmitting current to the pipeline system.

Dead legs
Refers to those pipeline bypasses that may or may not contain trapped fluids, whose characteristic is their being blocked and, therefore, not having the flow present. Connections in the lower part of the pipeline that facilitate the deposit of sediments, water and/or bacteria, favoring the internal corrosion processes in the pipeline. Bypasses that cannot be subject to pigging (internal cleaning with scrapers) are also considered dead legs.

Deconsignment
Operation of part of a pipeline or its equipment after an intervention by the Maintenance Sector in order to ensure the conditions that guarantee the absence of risks to health, safety and/or the environment, and preserve pipeline integrity. For example: checking completion of a task (caps, bolts), correct filling of liquids and draining of pipes, setup of instruments, cancellation of contingency operational procedures, etc.

Delimit
To set the limits of an area or specific space. Scope of delimitation may be two-dimensional or volumetric.

Delivery connection
Mechanical facilities that are not underground, used to join the pipeline with the transported product receiving system located along the pipeline.

Dent
Depression or hollow in the pipeline surface produced by an external agent, either by impact, scratch or external pressure.

Derate
To set a safe operating pressure for a pipeline while making the repairs that limit its maximum operating capacity, according to its design.

Dielectric oil
Oil with physical and chemical properties enabling electric insulation and cooling of electrical equipment, such as transformers and cathodic protection rectifiers.

E

ECDA
External Corrosion Direct Assessment - Structured methodology that combines pre-assessment, indirect inspection, direct examination and post-assessment, in order to assess pipeline integrity due to the threat of external corrosion.

Electrolyte
Chemical substance, or a mixture thereof, either liquid or solid, containing ions that migrate due to the action of an electric field.

ERW
Electric Resistance Welding - Used to manufacture pipelines with longitudinal seam weld.

F

Failure mechanism
Physical, chemical or other process which leads to a failure.

Failure mode
Observed effect or geometric configuration of a structure when it fails. It is the result of a chain of causes and effects that ultimately produces a failure (elastic or plastic deformation, ductile or fragile rupture, fatigue, corrosion, wear, impact, etc.).

FBE
Fusion Bonded Epoxy - Type of protective coating to protect buried pipelines from external corrosion, based on thermoset resin (based on phenolic epoxy or on epoxy of any other type) applied electrostatically as dust in plant or in construction (for welded joints) on the surface of the pipeline, which is blasted and heated at around 220 °C, according to the required characteristics and specifications. It is available as stand-alone coating and as two-layer coating. The latter is applied when mechanical protection is required apart from corrosion protection, or for managing fluids transported at high temperatures (higher than 80

°C). It is also used as a component of the three layer polyethylene (TPE) and three layer polypropylene (TPP) systems. It is currently used as interior coating for pipelines managing corrosive fluids.

Flash point
The lowest temperature of a liquid at which its vapors form an ignitable mixture with air.

Flow
Amount or volume of the flow of a water current, river, stream or transportation system during a period of time at a specific point or section. It is generally measured in m^3/second in the case of water currents, and in m^3/hours in the case of transportation systems.

Flush
Tangential probe or mass loss coupon of tangential insertion to the internal wall of the pipeline.

G

Galvanic cells
Electrochemical system transforming chemical energy into electric energy. They usually consist in two different electrodes joined electrically and submerged in an electrolyte. The union of two electrodes of the same nature submerged in different electrolytes is also considered galvanic cells. In the latter case, the ionic union between the solutions is required.

Galvanic pair
Electrical connection between two different metallic elements in which, due to their nature, one acts as the anode and the other as the cathode.

Geodynamical assessment
Estimate, definition or calculation of the characteristics, mechanisms, magnitude and scope of the geodynamic, geological and hydrodynamic processes, their real or potential risks and their effects on a certain physical structure or sector of the land.

Geological fault
Fracture of soil or rock massif involving vertical and/or horizontally sliding of one side or part with respect to the other, which causes discontinuity. It may be generated by tectonic forces or seismic or volcanic activity.

Geomorphology
Study of landforms of a specific area, considering their origin, nature of rocks and soils, climate and different external and internal forces involved.

Geotechnics
Discipline that studies the geologic, geotechnical and geodynamic processes that may cause the external and internal forces of the Earth in a certain area in order to determine the actual or potential risk for works or physical structures and/or the planning, calculation and design of reinforcement or construction systems that may guarantee, within reliable limits, their safety and stability.

GIS
Geographic Information System - Integration of hardware, software, geographic data, cartography, images and personnel, designed to capture, store, manage, analyze and present in any form the data that refers to a location in order to solve complex planning and management problems. It may also be defined as a model of a part of the reality referred to a system of earth coordinates built to meet specific information needs.

Gully
From the metallurgical viewpoint, it is the mark or pitting produced by bacterial corrosion. From the geological viewpoint, it is the ditch cut on earth surface by runoff water. It develops mostly in arid areas with heavy occasional rainfalls, as a ditched surface with grooves - in general shallow grooves - separated by steep watersheds. They have a stronger impact on soft and incompact materials, such as clayish and loamy soils.

H

HAZ
Heat-Affected Zone - Used in electric arc welding processes. It is the portion of base metal that has been melted, but whose mechanical properties have been altered by the heat of the welding. Metal base adjacent to weld metal which is not melted in the welding process, but that reaches the steel transformation heat (723º C), generating hard structures susceptible to corrosion and cracking.

HAZOP
HAZard and Operability - The functional operability analysis is an operating risk identification technique based on the premise that operability risks, accidents or problems result from a deviation of the process variables with respect to the normal operation parameters in a specific system and at a specific stage. Therefore, whether applied in the design stage or in the operation stage, the systematic approach consists in evaluating, in all lines and in all systems, the consequences of possible deviations in all the units of the process, be it continuous or discontinuous. The technique consists in systematically analyzing the causes and consequences of some deviations in the process parameters through “guidewords."

HCA
High Consequence Area - Those locations where a pipeline release may have a significant adverse effect on a sensitive area (the environment or natural resources of a community), a permanently populated area or an occasionally populated area. It may also be referred to as Major Accident Area (MAA) or as each country may designate it according to its government regulations or to the social and environmental responsibility policy of each company, in absence of the former.

Height clearance
Minimum height at which the platform of a bridge or aerial structure shall be located in the maximum channel of a current or river.

Historical geology
Study, interpretation and characterization of geologic processes over time, which have resulted in the currently existing model in a determined area or region of the Earth.

I

ICDA
Internal Corrosion Direct Assessment - Refers to a structured inspection methodology to localize, characterize and evaluate the internal corrosion of the pipeline.

ILI
In-Line Inspection - Consists in the use of instrumented tools (smart pigs), ultrasound principles, magnetic flux, video or mechanical devices that travel through the interior of the pipeline propelled by the fluid transported or by other different mechanisms or means (for example: wire cables/umbilical cables), and enable determining the geometrical condition, metal losses, mechanical damage, stress and/or georeferenced pipeline location.

Impressed current
System by which the current required for the cathodic protection of a metallic structure originates in an external source. This external source can be a rectifier that, powered by alternating current, offers a direct current suitable for the protection of the structure, or alternative sources powered by solar energy or heat energy (thermogenerators). The external current available is impressed in the circuit consisting of the structure to protect, and the anode bed (scrap iron, silicon cast iron, titanium oxide, lead-silver, graphite, etc.). The dispersion of the electric current in the electrolyte is performed with inert anodes whose characteristics and application depend on the electrolyte. The positive terminal from the source shall always be connected to the anode bed, in order to force the discharge of protective current into the structure.

Indentation
For purposes of this Manual, indentation refers to the mechanical damage on the pipe surface and its coating produced by hard objects, such as rocks and other structures, leaving the pipe material exposed to the corrosion of the environment where it is located.

Infrastructure
Integrated services or elements (highways, potable water, schools, populations, crops, etc.) which enable the adequate operation of an economy.

Initial boiling point
According to ASTMD 86, the recorded temperature when the first drop of liquid falls from the end of the condenser.

Interference current
Electrical current disseminated in an electrolyte that flows down a circuit other than its own electrical circuit. It is particularly found in soils from sources such as cathodic protection, trams, electric trains, welding, electrostatic precipitators or telluric current. This current is also called stray current, erratic current, leakage current, etc.

J

Joints
Area of the pipeline where two independent segments of the pipeline (pipes) have been welded during the construction process to avoid release of the fluid they contain. Joint by heating, with or without another

material to manufacture pipes (longitudinal joint) or to form the pipeline (circumferential joint between pipes).

K

Karl-Fischer
The Karl-Fischer method is widely used in different industrial sector interested in determining water content in their products due to possible deterioration reactions and/or quality specifications.

L

Landmark
Permanent signal placed to establish or indicate the pipeline route, the boundary lines and the limits of estates. Signal placed in an uninhabited area to serve as a guide.

Land register
Detailed textual and graphical census of the characteristics, and technical and legal conditions of urban and rural estate. It may include public works, such as roads, channels, electricity lines, etc. This is complemented with a specific register of each unit or property.

LI
Langelier Index - Indicates the saturation of calcium carbonate in water, which is based on the pH, alkalinity and hardness. If the index is negative, it indicates that the water is corrosive; however, if the Langelier index is positive, the calcium carbonate may precipitate and form scales or tartar in the container or water pipes. It is an index that reflects the pH balance of water with respect to calcium and alkalinity; it is used in water stabilization to control both the corrosion and the scale of deposition.

M

MAA
Major Accident Areas.

Magnitude
In the case of earthquakes: measure or range of the energy released in the event; in the case of geodynamic processes: scope and destructive effects generated by the event on the physical infrastructure or area where it occurred.

Mass loss coupon
Metal probe of a known weight (corrosion coupon) exposed to the corrosive environment to be analyzed and monitored to determine the weight loss suffered during a specific period, after eliminating the corrosion products using adequate techniques.

Metallurgic notch
Stress concentrator consisting of a localized change in a metallurgic steel surface (hardening) produced by the effect of sudden and concentrated heat, such as the heat generated by the electric arc when the electrode jumps across the pipeline surface.

MFL
Magnetic Flux Leakage - Very common inspection technique to measure the loss of wall thickness and to detect defects such as circumferential cracks, pits and grooves.

It consists in the passage of a pig through the pipeline, which generates a magnetic field in the axial or longitudinal direction of the pipeline. The walls of the pipeline are magnetized in a uniform manner. Any irregularity transversal to the magnetic field produces a variation in the same; this variation is recorded by the sensors of the tool.

With this information, the tool quantifies the depth proportionally to the thickness of the pipeline, determines the width and length, and finally registers the odometric position and the hour position of the detected anomaly.

It is necessary to know the limitations of the MFL technique to be able to decide between the tool with circumferential or longitudinal magnetic field. For example, the tool with axial field has restrictions to detect narrow anomalies longitudinally oriented. Moreover, as the technique requires that the anomaly have volume, it does not detect cracks either. It is advisable to check the range of validity of the tool with the service provider, and supplement it with other techniques if necessary.

MIC
Microbiologically Influenced Corrosion.

N

NAEC
Narrow Axial External Corrosion - Narrow, deep corrosion axially oriented, preferably along a longitudinal welding seam.

NDT
Nondestructive testing.

Nital
Solution of white nitric acid: 1-5 ml methyl or ethyl alcohol (98% or absolute), or amylic alcohol (100 ml). Substance used in metallographic studies.

Notch
Mechanical or metallurgical damage of a metal surface. Stress concentrator facilitating the fatigue process of the pipe material.

O

On-Off technique
Technique used to check the cathodic protection systems by impressed current whereby the structure potential is measured with respect to the soil with a reference electrode (copper/copper sulfate electrodes are used in onshore pipelines) with the protection current *on,* and at the time of interrupting the electric supply in the source of the cathodic protection system.

Operations

a. Incidental operation

All runoff situations that are not part of the normal operation and can produce pressure above the MOP of the pipeline, (with or without performance of protective devices), such as improper block (partial or total), failure of the pressure control system (PCV), fall of the pumping system, etc.

Note: Special operations, which are not part of the operational routine of the pipeline, such as displacement with nitrogen, water injection for hydrostatic test, displacement by heating products recooled in the pipeline, etc., shall be the subject of specific study, and the resulting specific peak pressures shall be limited to the MAOP of the pipeline.

b. Normal operation

All runoff situations that are part of the normal operation of the pipeline, including: steady state conditions, change of operational organization, change in products, batching and startup and shutdown operations.

P

Passivation

Material or chemical inhibitors added through the fluid in the pipeline in order to reduce the corrosion rate.

Passivation film

Film on the metal surface formed by corrosion product where the corrosion rate has very low values and offers protection and barrier properties to the metal substrate. An example is stainless steel.

Patch

Application of a patch-type repairing device to eliminate a leak from a pipe during the repair process. Rounded patch whose chemical and mechanical characteristics are similar to those of the pipeline steel. It is applied by welding and used to repair local damage or damage in a small area, such as leaks due to pitting.

Pearson

Pipeline inspection technique to measure susceptibility of pipelines to corrosion and the condition of coating.

P&ID

Piping and instrumentation Diagram.

PCM

Pipe Current Mapper - Consists of a radiodetection system which enables the evaluation of the pipeline coating and its cathodic protection and the analysis of the level of protection of the pipeline against corrosion. PCM is a pipeline inspection technique to measures susceptibility to corrosion.

PIG

Piping Instrument Gauge - Also called scrapper. Gauge used to clean the interior of a pipeline or to separate two liquids transported along the pipeline. There are also instrumented pigs designed for in-line inspection (ILI), diagnosis of the mechanical condition of the pipeline, and georeferencing of its axis. It is inserted in the pipeline through launching traps and is dragged by the hydrocarbon flow (oil or gas), and received in the other trap at the end of the run. There are also bidirectional pigs that may be returned to the launching trap inverting the flow direction.

Pig or scraper launching or receiving trap
Mechanical device to introduce, launch and receive internal cleaning tools, product separation and in-line inspection of pipelines in full operation. It may also be called launching, distribution or receiving trap.

Piggable pipeline
A pipeline that has been designed with the elements required to allow the pig to run, as for example the pig trap, or with internal diameter variations smaller than those tolerable for inspection pigs.

Pipeline
Transportation system through pipes, including components such as valves, flanges, cathodic protection, data communication and/or transmission lines, and safety or relief devices. Liquid hydrocarbons and gases are transported through these pipes, and they are generally located underground, in dry, humid soils or under water currents. In some sectors, in order to overcome depression of the soil they are located in aerial structures.

Pipes
Pipe segments, approximately 6-m and 12-m long, manufactured of low-alloy carbon steel, with or without longitudinal seam, in various diameters, widths and material grades, used in the construction of pipelines.

Predictive maintenance
- Technique to forecast the future point of failure of a segment or section of the pipeline to be addressed before failure, minimizing the downtime of the pipeline and maximizing its useful life.
- Maintenance mainly based on the detection of failures before they occur to allow time to correct them without affecting the service or stopping production, etc.

Pressures:
1. Maximum Operating Pressure (MOP)
Maximum pressure to which each point along a pipeline is subject under normal conditions. It is limited by the MAOP of the pipeline. The MOP is the result of the composition of[2] the following pressure fractions along the pipeline:
a) Pressure in steady state conditions;
b) Pressure in transient, non incidental conditions;
c) Pressure developed during startup and shutdown (MSSP)
d) Pressure at static conditions (pipeline shut) (SP)

2. Maximum Allowable Operating Pressure (MAOP)
Maximum pressure at which each point along a pipeline can be operated in accordance with the standard adopted for the specific project and construction, depending on the project pressure or on the hydrostatic test performed, or determined upon verification of the structural integrity or alteration of pressure class of the accessories installed. This pressure shall be between the MOP and the project pressure.

3. Nominal Pressure (PN)
Internal pressure calculated based on the nominal thickness, corresponding to a pressure affected by a project or design factor (for example, 72%) of the runoff limit of the material (Barlow).

[2] "Pressure composition" is the determination of the maximum pressures developed along each point of the pipeline for each planned operation.

4. Hydrostatic Test Pressure (HTP)
Hydrostatic test pressure at the test point or pressure at any point of the section tested. The km/spot height of the tested point shall be reported.

5. Maximum Incidental Pressure (MIP)
Maximum pressure to which each point along a pipeline is subjected during incidental operation. It is limited to 1.1 x MAOP of the pipeline.

6. Maximum Startup and Shutdown Pressure (MSSP)
Maximum pressure to which each point along a pipeline is subject during normal startup and shutdown procedures. Despite its short length (transient), it occurs with high frequency and shall be limited by the MAOP of the pipeline.

7. Minimum Structural Pressure Required (Preq)
Minimum structural pressure required for each point along a pipeline, depending on normal or incidental conditions of operation, and considering the control and protection devices and protection installed. The Preq is the result of the composition of the maximum values between the MOP and the MIP/1.1, that is to say: Preq = Max (MOP; MIP/1.1), and represents the minimum pressure that every point along the pipeline shall withstand, according to the standard adopted for the specific project and construction.

8. Project/design pressure
Pressure adopted for mechanic dimensioning of the pipe and other pipeline components, in accordance with the applicable standards.

9. Partial pressure
Pressure of a gas on a liquid which is in equilibrium with the solution. In a mixture of gases, the partial pressure of a gas is as many times the total pressure of the fraction of gas in the mixture (by volume or number of molecules).

Preventive maintenance
Planned actions or works to avoid the occurrence of failures, keeping the pipeline in good condition and continuous operation and correcting in a timely manner any anomaly detected during inspections or technical control and monitoring checkups previously performed.

Probability of failure
Probability of occurrence of a leak or failure in the system at a particular period of time. It can also be defined as the level of susceptibility of occurrence of damage or loss of integrity for every potential threat in the system.

Prospection
Excavation or vertical well, not very deep and covering a small area, from whose bottom or walls material samples are extracted for identification and/or laboratory testing. This is also referred to as “test drilling.”

R

Ratio
Relation, proportion.

RBI

Risk-Based Inspection - Methodology to establish, from the risk assessment in a static equipment (pipeline, tank, container, furnace, boiler or others), the threats and failure modes that said equipment may present in order to define the methods and techniques, frequency and scope, required to make them evident. Monitoring and inspection programs, and mitigation actions, both of threats and consequences, are defined based on the RBI.

RCA

Root Cause Analysis. Methodology to identify physical, human and latent causes of any type of failure or incident that occurs once or several times, in order to adopt the predictive, preventive and/or corrective actions required to prevent its repetition or occurrence, and thus, reduce the costs of the process life cycle, improve safety and increase business reliability.

It is a systematic and structured process that analyses in detail the chain of events and conditions (causes and effects) resulting from a "primary effect", with the exclusive purpose of finding optimal solutions that in the future will prevent, mitigate or eliminate the consequences of the "primary effect."

Generally, this "primary effect" is directly related to problems identified or sudden failures of equipment or processes.

Therefore, the development of this process allows making proper decisions regarding technical, management and economic aspects, ensuring effective solutions according to the corporate guidelines.

Residual life

Period of time remaining until the end of the useful life of a component or facility, which ends when the capacity to provide a service under acceptable technical, safety and financial standards reaches a limit.

Return period

Period of time, generally expressed in years, when a natural event may occur or repeat itself, such as earthquake, flood, rain, swell, etc. It may be estimated for a certain event or calculated assuming its magnitude and interrelating the data and corresponding historical information.

Right of way (RoW)

Strip of land where the pipeline or other components of the system (valves, signage, power supply, etc.) are located. It is established in the construction and operation stages.

Risk

Ratio between the probability and the consequence of a failure. This ratio is arithmetic when the risk assessment methodology is quantitative, and may be a matrix combination when the risk assessment is qualitative.

It may also be defined as the measurement of probability and severity (consequence) of the destructive or adverse effects generated by the occurrence of a process or threat to the life and health of people, stability of physical structures and/or impact on the environment. It is quantified as the product of occurrence probability by consequences, i.e., the combination of probability (frequency of occurrence) and the consequences (severity) of a risk, confined to an environment or area, during a specific period of time.

Risk estimation or assessment

Process used to measure the level of risks on life, health, the environment or property, including an analysis of frequency or probability of failure for each threat, an analysis of the consequences and their integration.

Judgment and values, either explicitly or implicitly including considerations regarding the importance or severity of the estimated risks, as well as the related social, physical, environmental and economic consequences, play a role in the decision-making process for risk estimation and assessment with the purpose of identifying alternatives for risk mitigation or reliable management.

RMU
Remote Monitoring Unit - Used for real-time visualization of the operating conditions of Cathodic Protection Rectifiers (CPRs).

Rocky massif
Descriptive term to indicate that certain space is occupied or formed by rocky material with physical characteristics from solid and continuous to fractured and meteorized rocks, where the presence of soils is not significant.

Root cause
Circumstance associated with the design, manufacture, installation, use and maintenance, which led to a failure.

S

Sacrifice anodes
Metal with a normal oxidation potential higher than that of the metal structure to be protected, thus consumed when emitting protective current. It is used in cathodic protection systems where the metal acting as anode is sacrificed (disintegrated) favoring the cathodic metal. In this type of installation, the anodic material is consumed depending on the demand of the protective current of the structure to be protected, the electrolyte resistance and the resistance of the anodic material during the consumption process.

S&W
Sediment and water. Material that coexists with a hydrocarbon liquid but is different from it, and that requires a separate measurement for reasons such as sales accounting. The material can include free water and sediment (FW&S) and emulsified or suspended water and sediment (SW&S).

SCADA
Supervisory Control and Data Acquisition.

SCC
Stress Corrosion Cracking - Cracking of a material by the combined action of corrosion and tensile stress, which may be residual, as the one in the zone affected by welding heat, or applied, as the one produced by the internal pressure of the pipeline or by external loads.

Sediments
Rocky material residues of diverse sizes that eventually divide into smaller fragments. Gravity and transport by the action of water or wind deposit and accumulate them in the lowest areas of the soil relief.

When referring to pipeline corrosion, it is the water and particulate matter that accumulates inside the pipes causing flow restrictions and promoting the internal pipeline corrosion.

Segment
Action of dividing a pipeline into segments, depending on the HCA or MAA, and on its construction characteristics (diameter, thickness, material grade, pipeline age, coating condition, coating type, aerial and buried sections, block valves, scraper launching and receiving traps, or others) to facilitate the risk assessment exercise.

Site clearing
Cutting and pruning or green areas (with vegetation). Action of removing vegetation (bushes, grass and trees about to fall) from the right of way or the strip of the pipeline to enable visual inspection, patrolling and maintenance activities.

Slope
Inclined surface or grade of steepness of the ground with respect to its length; it is measured by the angle it forms with the horizontal line or by the number of units of rise per each 100 units of length. Example: slope of 3:100. Other terms: hillside, bank.

Soil resistivity
Specific electric resistance of the soil, expressed in ohm-cm.

Spot height
Height or elevation of a point in the ground or sea with reference to the sea level or to a predefined and duly marked reference level.

SRB
Sulfate reducing bacteria.

Steady state conditions
The hydraulic conditions of the pipeline under which all the operational parameters remain approximately constant over a period of time.

Subsidence
Results of the erosion caused by water. Subsidence may be general or localized.

Survey
Preliminary study to gather information on specific or predetermined areas, characterize them and define their risk level and vulnerability with respect to any structure or work located therein.

Susceptibility
Easy occurrence of a natural geodynamic process based on the local conditions and characteristics of the soil. The susceptibility of occurrence of a triggering factor, such as rain or earthquake, is not considered. Susceptibility may be evaluated in the following ways:

I. **Experience system** Using direct information on the characteristics of the soil and rocks, the geomorphology of the area, the experience or knowledge of the mechanisms that generate these processes and the geotechnical history of the area. These data are inter-related to characterize and estimate the scope, inherent or actual risk, and the magnitude of occurrence of an event, and

II. **Theoretical system** The greatest number of factors in the problem area that are deemed to be involved in the occurrence of a natural process are mapped and dimensioned. These data are processed by software to determine the number of probabilities and failure conditions.

For the other threats to which the pipeline is subject, it is also the highest or the lowest probability of occurrence of damage or deterioration of the pipe.

T

Talweg
The deepest part or line of a water current or river where the current speed is higher. It also defines the deepest part of a valley.

Test drilling
Boring by percussion or in general rotatory boring to extract samples for identification of crossed materials and/or laboratory tests. Usually, special instruments may be adapted or installed to perform different types of on-site geomechanical and hydraulic tests. Scope in depth depends on the type of equipment and/or the characteristics of the soil under study and the purpose of the project.

Threat
Environmental, operating, natural or anthropic condition, related or unrelated to the weather, which might cause deterioration in pipeline integrity and even pipeline failure. Alternatively, it is the probability of its occurrence in a certain period of time or the susceptibility of occurrence of pipeline damage

Trial pit
Excavation performed in the soil to determine the existence of minerals or the nature of the subsoil.

W

Water content
Percentage of water in a solution.

Wire cable or sling
Device used to lift or carry load.

5. Identification of Pipeline Baseline

The integrity of pipeline systems shall be considered from its initial planning stage and during design and construction. Pipeline integrity management begins with adequate system design and construction. The design specifications, the pipeline construction conditions and the records kept during this stage provide information to establish the baseline of an integrity management system.

The integration of such information is key to manage an integrity system. Key elements of the integrity management structure are the registration, compilation and integral management of all the information available. This allows the pipeline operator to determine where the highest incident risks are and to take the corresponding proactive actions to mitigate them.

Risk assessment as the basis of a pipeline integrity program is an analytical process involving the integration and analysis of information about design, construction, operation, maintenance, assays, testing, monitoring, drawings, right of way and areas where the pipeline extends.

The assessment of risks related to pipeline integrity is a continuous process, so the operator shall periodically gather additional information generated from its experience in the operation of the systems. This information, classified by factors, and according to its importance and quality, shall allow the operator to perform the risk assessment and adjust the integrity plan, which may result in changes in frequency or inspection methods, and even in pipeline changes.

The first step that the operation shall take to address potential threats that might affect pipeline integration, at any point along the pipeline, is to compile information to determine the risks to which the pipeline transportation system could be subject. At this stage, the operator compiles checks and integrates the data required to know and understand the actual pipeline condition, to identify and locate the specific threats to integrity, and to measure the level of the consequences of pipeline failure. The factors or type of data required to support risk assessment include information about operation, maintenance, pipeline design, operation history, failure modes and history, inspection report, tests, monitoring of corrosion control systems, and populations and sensitive areas that may be affected by the spill, fire and/or explosion of the transported product.

The compilation of data to identify the pipeline baseline and to support the subsequent risk assessment exercise shall not only consider the damage mechanisms that the operator may identify as currently affecting the pipeline. It is also advisable to consider if there are other potential threats that have not evidenced themselves in the system yet.

Anyway, in order to facilitate the users of this Manual the identification of a pipeline baseline, following are some sources and types of information that are essential to collect in order to establish a pipeline integrity management program.

5.1. Pipe Material Records

It is necessary to determine whether the pipeline has a seam or not (seam welding), the steel grade, the nominal pipeline diameter, the nominal and current thickness (if possible), the manufacturing year and the manufacturer of the pipeline. It is also necessary to establish material certification records, purchase documents containing technical specifications, reports on manufacturing process control and records of certification of pneumatic or hydrostatic test. This information shall allow determining the design pressure and the safe operating pressure, valuing the effect of external loads, identifying potential failure modes to which some pipelines may be more susceptible, tracing any failures related to pipe quality and establishing the correlation of failures of other pipelines as regards the pipeline manufacturer, and identifying the most suitable inspection methods to determine different failure modes. The standard used for pipeline specifications, as well as its issue number, shall also be recorded.

5.2. Pipeline Construction Records

Information shall be available to establish the type and the process of the circumferential welding used, the type and conditions of the anticorrosive coating applied to the pipe and the circumferential joints, the type of filling material, the pipeline depth, and the arrangement of the pipes along all the pipeline (diameter, thickness, grade, longitude, curves). This information may be obtained from design and construction standards or procedures applied during pipeline assembly, quality control records on field welding, construction control records, welding records (WPS and PQR), manufacturer's records if the pipe coating was applied in the manufacturer's plant or applicator's records if it was applied in the applicator's plant or in the field, records on whether the pipe was purchased stripped and construction sketches. This information shall allow checking pipeline compliance with good design and construction practices in order to determine any failure mode to which the pipeline may be susceptible at any point, and to support segmentation to facilitate the risk assessment exercise.

5.3. Infrastructure Records

It is necessary to have information about the location of block valves and check valves, crossing of other pipes or structures, crossing of roads, railroads, channels or rivers (and whether these are cased or not), crossings or parallelisms with high tension lines, aerial or buried pipelines sections and interfaces with aerial or buried pipelines. It is also necessary to know the type of support for aerial sections, the location of crossings or parallelisms with direct current lines of trams or subways, the pipe sections susceptible to external load due to heavy traffic, the location of launching and receiving traps for internal cleaning tools, the location of dead legs or segments with no flow or stagnation of water and/or sediments, and the location of filtering systems. This information may be obtained from the pipeline construction drawings and the monitoring reports of maintenance and safety personnel, and will allow identifying different threats and damage mechanisms on the pipeline, as well as pipeline segmentation, thus facilitating the risk assessment exercise. All this information shall be available in a GIS database.

5.4. Records Related to Aggressiveness of the Medium (Fluids and Soil)

It is important to know the type of transported fluid and fluid characteristics (molecular weight, initial boiling point, flash point) based on a laboratory quality certificate. Information is also required about the characteristics of water or sediments that may be present in the transported product or drained from pipelines or tanks supplying the product to be transported, by means of physical, chemical and microbiological analyses. Similarly, it is important to know the aquatic environment and soil resistivity profile and the soil classification in terms of its configuration; and to establish the level of carbonates, sulfates, bicarbonate, chloride, pH and bacteria by means of physical, chemical and microbiological analyses.

It is also important to keep records on the physical and chemical analyses of the residues obtained during pigging, and on the results of corrosion coupons and probes.

This information will allow establishing pipeline susceptibility to internal and external corrosion, thus facilitating the risk assessment exercise and the establishment of action plans to determine and mitigate such risks.

5.5. Right-of-Way or Easement Records

Geological studies, geotechnical analyses and reports on strip of right of ways will allow having information on the susceptibility of pipelines to be affected by threats related to natural forces.

This research is reported in a geotechnical and geological report containing the following information, among other data: soil type and characteristics; intersection and location of water currents, urban infrastructure, roads, etc.; location and boundaries of segments with potential risk from natural forces (geotechnical zoning); and, in pipelines segments under instability conditions and risk from natural forces that cannot be avoided due to topographic or hydrographic constraints, monitoring reports and/or reports on stabilization or strengthening works recommended during construction and maintenance of the right of way.

Apart from determining the type, characteristics and conditions of the soil along the pipeline strip of land, it is important to know the method to determine easement, the legal procedures followed and the location of such records. This information allows establishing the susceptibility of local populations regarding the pipeline.

5.6. Coating Records

Apart from the information regarding the type, characteristics and conditions of the coating applied during pipeline assembly and construction, it is important to have information regarding coating age, thermal insulation and current conditions. It is also important to know the conditions of the thermal insulation applied to some pipelines operating with hot products, and the concrete coating applied to submarine pipelines located under lakes, rivers, marshes and sea. This information allows establishing the susceptibility of the pipeline to external corrosion and the action plans to mitigate it.

This information may be obtained from pipeline construction records, records on DCVG, Pearson, ACVG or PCM inspection procedures, or in-line inspection reports.

5.7. Cathodic Protection System Records

It is necessary to know the type of cathodic protection installed (impressed current or galvanic protection), its location, the anode bed characteristics and whether a remote monitoring unit is available. It is also necessary to have information about the condition of the electric insulation among pipelines and plants and delivery points, aerial crossings, aerial pipelines and location of potential measuring points. This information will allow determining whether an adequate cathodic protection system has been implemented according to the coating type and condition, and therefore, the susceptibility of the pipeline to external corrosion. This information may be obtained from pipeline construction records and from periodic inspections performed to the CPRs.

5.8. Preventive Maintenance Records

It is important to determine the cathodic protection level, the coating condition, the pipeline condition, the types and rates of internal corrosion, the chemical treatment and its effectiveness, the levels of stress due to external load, the condition of prevention signs, the condition of the right of way (floods, landslides, gullies, subsidence, forest fires), aerial and sub-fluvial crossing condition, level of activity on right of way, populations, high-sensitivity areas. This information may be obtained with techniques such as CIPS, DCVG, PCM, ILI, internal corrosion monitoring, pipeline load or displacement monitoring, inspections and patrolling of right of way. It will allow determining the susceptibility to threats, such as internal corrosion, external corrosion, third-party damage and natural forces, as well as the effectiveness of mitigation actions and an assessment of the consequences in case of failure.

5.9. Operation Records

Operational data and operational and control procedures are necessary to establish the maximum operating pressure, the pressure fluctuation during service, the characteristics of the transported product, the operating temperatures, the control systems used for flow and pressure variables, the relief and cutoff systems, the communication, management and control of infrastructure and operational process changes, the failures arising from inadequate operation, the in-line leak detection systems, and the training and skills of system operators. This information supports the assessment of the threats related to internal corrosion and inadequate operations and the extent of the effects or consequences in case of pipeline failure. This information may be obtained from operation manuals, operator's duties and responsibilities manuals, HAZOP studies, failure historical data, historical records on operational variables, P&ID sketches, audit report on the quality management system, and incidents and accidents report.

5.10. Historical Failure Records

This information is very important to reveal proved damage mechanisms and determine the level of impact on spill areas in real situations. In some cases, it also allows extrapolating these damage mechanisms, the remediation actions taken and their effectiveness for other pipelines, and, of course, also to know the effectiveness of the contingency plans of the company and the contingency plans for pipelines located in a strip of land containing pipelines of more than one operator. The historical failure information shall cover the failure cause: pipe manufacturing defects, internal corrosion, external corrosion, SCC, flanged joints, illegal connections, attacks, involuntary third-party damage, operational errors and natural forces. The historical failure information shall also contain data on spilled volumes, affected areas, damage to people, infrastructure and the environment, and the costs related to the event management. It is also important to keep historical records on inspection and maintenance created for the pipeline, mostly on those segments next to the incident or accident.

5.11. Corrective Maintenance Records

This information shall include the results of pressure tests, pipeline replacement segments, construction of bypasses, mechanical pipeline repairs, anti-corrosive coating replacement, thermal insulation replacement, cathodic protection reinforcement, reinstatement of coating in aerial or buried pipeline sections, reblocking of aerial pipelines, updated pipeline drawings and condition of electric insulation in stations, delivery points, aerial crossings and support of aerial pipelines. Information on maintenance is necessary to determine which events have caused such actions, their effectiveness and their application to other pipelines. It also enables to know the pipeline integrity level. It directly supports the risk assessment exercise. Information on maintenance may be obtained from maintenance management systems, bypass construction reports, records on replacement and/or reinstatement of pipeline segments, records on lessons learned and reports on pipeline inspections performed by maintenance and safety staff.

5.12. Records Related to High Consequence Areas and Mitigation of Consequences

This information allows establishing which pipeline segments may affect, in case of a failure, high consequence areas on which pipeline operators shall focus their attention. It may be obtained from contingency plans, environmental management plans, environmental agencies and regulatory agencies in each particular country. It includes the location of especially sensitive areas and populations where the communities may be affected by a spill, such as marshes, rivers, lakes, animal and plant reserves, watersheds for human consumption, recreation and tourist areas, commercially navigable waterways, historical or archaeological sites and any other sector which the operator, according to the regulations of each particular country or its own social responsibility and environmental policies, might consider fit to include in the risk assessment exercise. During pipeline maintenance or construction, any discovery of historical or archaeological sites shall be notified to the competent authorities or entities.

In the case of gas pipelines, it is important to know the wind condition mapping of the strip of land. In the case of underwater pipelines, it is important to know the current and wind conditions, as well as the effect of erosion.

In the case of old pipelines, the fact of not having all the information on the above-mentioned items is not an obstacle for the operator to perform an initial risk assessment exercise and develop action plans to maintain the integrity of its pipelines. Not knowing the condition of the pipeline may result in a high initial risk, which requires monitoring, tests and inspections to confirm or to reduce such risk level. Information may improve in quality and quantity as the methodology presented in this Manual is implemented, thus leading to a higher level of confidence in pipeline integrity management.

5.13. Checklist for Identification of Pipeline Baseline

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST IDENTIFICATION OF PIPELINE BASELINE TRANSPORTATION SYSTEM							
#	Aspect / Item / Characteristic	Required		Available		Location of data	Comments
		Yes	No	Yes	No		
1.	**Are there any pipe records?** Type of pipe, material grade, nominal and actual thickness, manufacturing year, manufacturer's certificate						
2.	**Are there any records on welding, assembly, construction and installation of the pipeline and on hydraulic tests?** Welding process (WPS and PQR), type of coating, type of filling, type of mechanical protection, pipeline depth, pipeline arrangement (diameters, grades, thicknesses, longitudes, curves), hydrostatic text, installation year.						
3.	**Are there any infrastructure records?** Location of block valves and check valves, crossing of other pipes or structures, crossings of roads, railroads, channels or rivers (and whether these are cased or not), crossing or parallelism with high tension lines, aerial or buried pipelines sections, interfaces with aerial or buried pipelines, type of support for aerial sections, crossing or parallelism with direct current lines of trams or subways, pipe sections susceptible to external load due to heavy traffic, location of launching and receiving traps for internal cleaning tools, location of dead legs or segments with no flow or stagnant water and/or sediments and filtering systems, and information on access roads to valves and crossings of rivers, roads and railroads.						
4.	**Are there any records related to aggressiveness of the medium (fluids and soil)?** Type of transported fluid; fluid characteristics (molecular weight, initial boiling point, flash point), characteristics of water or sediments that may be present in the transported product; soil resistivity profile; classification of soils according to configuration; and determination of the level of carbonates, sulfates, bicarbonates, chlorides, pH and bacteria.						
5.	**Are there any right-of-way or easement records?** Geological studies, geotechnical analyses, reports on strip of right-of-ways, reports on right-of-way maintenance, reports on geotechnical stability monitoring, tenure or easement negotiation documents.						
6.	**Are there any coating records?** Age, type, characteristics and conditions of current anti-corrosive coating and thermal insulation.						
7.	**Are there any cathodic protection system records?** Type of cathodic protection installed (impressed current or galvanic protection), CPR location, anode bed features, remote control units, electric insulation among pipelines and plants and delivery points, aerial crossings, aerial pipelines and location of potential measuring point and points of interconnection or electrical bridge circuit.						

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST IDENTIFICATION OF PIPELINE BASELINE TRANSPORTATION SYSTEM							
#	Aspect / Item / Characteristic	Required		Available		Location of data	Comments
		Yes	No	Yes	No		
8.	**Are there any preventive maintenance records?** Cathodic protection levels, coating condition, coating depth, mechanical condition of pipeline, types and rates of internal corrosion, chemical treatment and its effectiveness, levels of stress due to external load, condition of prevention signs, condition of the right-of-ways (floods, landslides, gullies, subsidence, forest fires), condition and maintenance of pipeline relief valves and block valves, maintenance of pig launching and receiving traps, aerial and sub-fluvial crossing condition.						
9.	**Are there any operation records?** Operational data, operational and control procedures, pressure fluctuation during service, characteristics of the transported product, traceability of batches in the pipeline, operating temperature, control systems used, relief and cutoff systems, communication, management and control of infrastructure and operational process changes, failures arising from inadequate operation, in-line leak detection systems, and training and skills of system operators.						
10.	**Are there any historical failure records?** The historical failure information shall cover the failure cause and be classified according to: pipe manufacturing defects, internal corrosion, external corrosion, SCC, flanged joints, check valves and block valves, illegal connections, attacks, involuntary third-party damage, operational errors and natural forces. The historical failure information shall also contain data on spilled volumes, affected areas, infrastructure and people, and the costs related to the event management.						
11.	**Are there any corrective maintenance records?** Results of pressure tests, pipeline replacement segments, construction of bypasses, mechanical pipeline repairs, anti-corrosive coating replacement, thermal insulation replacement, cathodic protection reinforcement, reinstatement of coating in aerial or buried pipeline sections, reblocking of aerial pipelines, updated pipeline drawings, condition of electric insulation in stations, delivery points, aerial crossings and support of aerial pipelines, maintenance of aerial and sub-fluvial crossings, maintenance of pig launching and receiving traps and maintenance of relief valves, check valves and block valves.						
12.	**Are there any records related to high consequence areas and mitigation of consequences?** Contingency plans, environmental management plans, mutual aid plans, agreements on shared right-of-ways, maps of environmental organizations and regulatory state agencies of each country, location of especially sensitive populations and areas: marshes, rivers, lakes, animal and plant reserves, watersheds for human consumption, recreation and tourist areas, commercially navigable waterways and historical or archaeological sites.						

Table 1: Checklist for identification of pipeline baseline

6. Risk Assessment and Management

Integrity management based on risks shall be considered a comprehensive and continuous process that includes: risk assessment, monitoring, inspection and mitigation (maintenance), data integration, periodic risk reassessment and definition and adjustment of action plans, establishment and measurement of management indicators, and change control.

Risk assessment is the estimation of risk for decision-making purposes. In risk assessment, information is usually computerized to facilitate understanding of the nature and location of risks along the pipeline. Experienced staff with good knowledge of pipelines (operation and maintenance), as well as experts in the different threats to which the pipeline may be subject, shall participate in the risk assessment exercise so that the data, assumptions and results from such assessment are checked with proper criteria and the assessment and the corresponding action plan for mitigation of such risks are reliable.

The definition of the action plan, its application, the measurement of its effectiveness, its adjustment and the change control are continuous processes, and each operator shall define the frequency of such reviews.

6.1. Definition of Risk

The methodology to implement an integrity program is supported by risk assessment. Risk is mathematically defined as the product of the probability of occurrence of a failure and the consequences of occurrence, as follows:

R = PoF * CoF

Where:
- R: risk
- PoF: Probability of failure.
- CoF: Consequences of failure.

The probability of failure derives from the assessment of each threat considered and described in Chapter 7, Failure Mechanisms Due to Threats, of this Manual.

The consequences of failure imply the need to establish high consequence areas or major accident areas, as stated in Chapter 5, Identification of Pipeline Baseline, records related to high consequence areas or major accident areas and mitigation of consequences.

The HCA or MAA are those sites where a leakage or spill of a hazardous substance may occur and the workers, the population or the environment become exposed to a serious, immediate or deferred hazard. Pipeline operators shall be familiar with the standing regulations on pipeline integrity systems management and with the definitions of HCA and MAA provided by the regulations of the countries where they operate. New HCA or MAA may appear as new data on populations and environmental resources become available. It is important that the operator make sure that its integrity management program contains the most recent information provided by the government and by its own data compilation methods.

This information allows the pipeline operator to consider the need to divide the pipeline in different segments where these HCA or MAA would be affected by a leakage. This would facilitate the risk assessment exercise and the pipeline operator will be able to allocate its resources to such segments with more emphasis, in order to mitigate the threats and focus its contingency response plans. The following pipeline characteristics may also be used for pipeline segmentation: changes in diameter, thickness, pipe material grade, type of coating, pipeline age, coating condition, block valves, aerial sections, buried sections, etc. As an alternative, the operator may apply the risk calculation methodology along the pipeline with no segmentation according to HCA and MAA, considering that the whole pipeline has the same level of consequence. For example, pipes on animal or plant reserves would require the same measures to maintain the PoF at a tolerable level as the rest of the pipes in order to minimize the likelihood of occurrence of accidents at any point along the pipeline.

6.2. Risk Assessment

Risk assessment is performed by a group of experts. A risk assessment team should be composed of civil officers in charge of right of way, operational staff, staff in charge of pipeline mechanical maintenance, environmental experts, physical safety experts, pipeline engineering experts, pipeline construction experts, corrosion control experts, experts on materials and experts on risk assessment and management.

There are different methodologies to assess and measure risk levels, such as:

a. Subject Matter Experts (SMEs)
Subject matter experts (SMEs) are people who have experience and expertise in specific areas of operation, maintenance, integrity, and reliability of pipelines, and/or have extensive information from technical literature. SMEs are able to assign relative values that describe the probability of failure for each threat and the resulting consequence (high, medium or low) to calculate the relative risk of each pipeline segment within a particular operation.

Other methodologies to assess and measure risk levels are: open consideration of events and potential risks; inspections segment by segment using alignment sheets or maps; and checklists with structured groups of questions to obtain information on potential risks and pipeline integrity aspects.

b. Relative Assessment Models
These are semi-quantitative models. The assessment is performed on the basis of the specific experience about the pipeline and on other information, and includes the development of risk models that focus on known threats that have historically impacted pipeline operations.

These approaches are considered relative risk models because the risk results are compared to the results generated by the same model. They provide a classification of relative risks for the decision-making process. Risk matrixes are used to measure the probabilities of failure and the consequences of failure for each potential threat to the pipeline to be assessed.

Some techniques commonly used to calculate the probability of failure and the consequence are the indexing technique and the logical ports, following a semi-quantitative model that reduces the relativity and subjectivity of the calculations. These basically consist in numerically evaluating the parameters established for each variable directly affecting the PoF and the CoF, with the risk being the product of the two ranges of variations. The resulting number is translated into qualities by means of a Risk Matrix which compares the PoF vs. the CoF and allows establishing different risk assessment levels.

Risk matrixes like the one shown in Figure 4 are generally used, as they enable higher risk discrimination based on the PoF and CoF.

c. Scenario-Based Models

This approach is based on the logical models that build event trees, decision trees and failure trees, which lead to a level of risk and include both the likelihood and the consequences of such events. The model incorporates detailed information on the design, operation and maintenance of the facilities, the reliability of the components and the potential effects on health, safety and the environment.

d. Probabilistic Models

These quantitative models are more complex and demanding with regard to information requirements.

Instead of using a comparative analysis, this approach is based strictly on the acceptable probabilities of risk established from the data accumulated by pipeline operators. With detailed information and extensive accumulated data on specific pipelines, probabilistic algorithms are developed that incorporate the probability of failure for each threat and potential associated consequence.

The operator of transport systems is responsible for implementing the risk analysis method that best meets its needs, so it is necessary to fully understand the strengths and limitations of each risk assessment method before adopting a long-term strategy (it is possible to use more than one type of model throughout the entire system of a single operator).

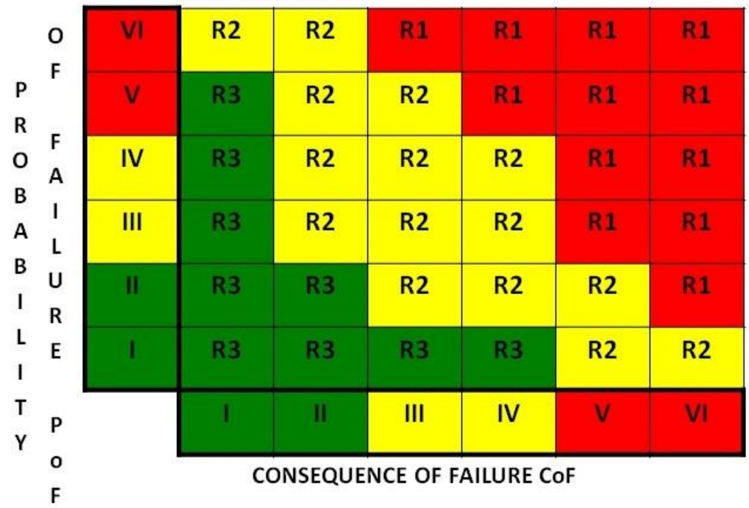


Figure 4: Risk matrix for pipelines

6.2.1. Calculation of Probability of Failure (PoF)

Different variables are involved in the assessment of probability of failure. They define the factors to be taken into consideration.

The variables considered are:

a. **Environment** or medium to which the pipeline may be subject (for example: type of soil, aggressiveness of soil, level of activity on the right of way, geological condition of the right of way)
b. **Design**, i.e., those aspects considered during the pipeline design and construction to mitigate threat to which the pipeline would be subject according to its layout (for example: type of coating, cathodic protection system, pipeline signage, monitoring system of the geotechnical condition of the right of way, mechanical protection, geotechnics works, greater thickness, others)
c. **Diagnosis** (Monitoring and Inspection), i.e., different means or actions with their respective frequencies, whereby the effectiveness of the mitigation measures considered during the design, construction and reinstatement can be proved (for example: determination of the cathodic protection levels, determination of the coating condition, interior corrosion rates, historical event for each threat, frequency and results of in-line inspections (ILI), landslide monitoring, diagnosis of aerial and sub-fluvial crossings, others)
d. **Reconditioning**, i.e., maintenance actions resulting from diagnosis (for example: repair and/or reinforcement of the cathodic protection systems, reinstatement of coating, ILI repairs, re-signage of pipeline segments, geotechnical stabilization works)

Matrixes to establish the probability of failure shall consider these variables and the factors that have a positive or negative influence on their implementation.

The following steps have to be taken into account in the assessment of the probability of failure:

1. Identify the deterioration or damage mechanism occurring during a specific time, considering normal operating conditions or the environment to which the pipeline is subject, and the variation of the same.
2. Determine the deterioration rate and/or susceptibility.
3. Quantify the effectiveness of the last integrity assessment and the maintenance program.
4. Determine if deterioration continues under the current conditions and predict the rate at which the tolerance of damage to the equipment or assets is exceeded, causing an imminent failure.

6.2.2. Calculation of Consequence of Failure (CoF)

In the calculation of the consequence of failure, it is necessary to consider the definition of high consequence areas or major accident areas for the pipeline to be assessed, as stated above, in order to assess the severity of the impact of a leakage or rupture on people's health and safety, facilities, communities, the environment, and the company economy.

In order to determine the consequence of failure, two kinds of analysis are usually taken into consideration:

a. **Qualitative analysis:** This method involves the identification of segments as stated above, in terms of HCA and MAA and physical characteristics of the pipeline, and the threats present as a result of operating conditions and transported fluids that may spill. The consequences of failure (environment, health, safety, image and financial impact) are assessed for each segment in a set of categories: very high, high, medium and low, according to the criteria defined in the risk matrix.

b. **Quantitative analysis:** The quantitative method implies a logical model with possible combinations of the effects of failure on the property, the environment, the personnel and the company. One or more failure patterns and results are usually considered (leak or rupture), and the consequence of failure is calculated on the basis of:

1. Type of transported fluid
2. State of process fluids in the interior of the equipment or assets (solid, liquid or gaseous)
3. Key properties of the process fluid (molecular weight, boiling point, flash point, density, etc.)
4. Operating variables, such as temperature and pressure
5. Failure mode
6. State of the fluid when exposed to environmental conditions (solid, liquid and gaseous)

Each company using this Manual may adopt or implement its own risk assessment model and define the methodology to rate the PoF and CoF for each potential threat to its pipelines.

6.3. Uncertainty

It is important to identify the role of uncertainty through risk assessment calculations. The risk model used by the company shall assume that things are "bad" until the data show otherwise. Therefore, an underlying issue about risk assessment is that "uncertainty increases the risk". This is a conservative approach that requires that, in the absence of significant data or the opportunity to benefit from all the available data, the risk be overassessed and not underassessed. Therefore, it is assessed lower, thus reflecting the reasonable presumption of bad conditions, in order to accommodate the uncertainty. The result is that the overall risk assessment is more conservative. As a general philosophy, this approach to uncertainty has the advantage, in the long term, of promoting the collection of data through inspections and tests. Uncertainty also plays a role in the rating assigned to operation and maintenance aspects.

An excessive conservatism, which could mask real problems, is avoided through the implementation of reasonable limits on the allocation of default values.

As part of the concept of “uncertainty”, the risk model information also has a useful life, which illustrates that the conditions are always changing and the most recent information is more useful than the oldest information. The results of the assessment represent a snapshot of the risk at a point in time. Finally, the age of information has little value in the risk analysis and this is reflected in the calculation of the risk. Examples of time-dependent variables that tend to increase the uncertainty with the passing of time:

- Increase in fatigue cracks
- External corrosion
- Internal corrosion
- Third-party damage
- Deterioration of pipeline coating
- Loss of depth of pipeline burial
- Excessive growth of grass in the RoW

- Loss of RoW markers
- Increased population density
- Effectiveness of cathodic protection

6.4. Information Required for the Risk Assessment

Chapter 5, Identification of Pipeline Baseline, presented the information required to support the risk assessment.

7. Failure Mechanisms Due to Threats

This Chapter of the Manual describes the different threats that may affect the pipeline integrity and failure modes, some time-dependent, and others time-independent or stable.

If despite monitoring and mitigation actions for such threats, these could generate a failure in the pipeline, it is necessary to apply measures to mitigate the consequences, among which are contingency plans, mutual aid plans and leak detection systems. The latter apply different principles and technologies, among which are:

- Acoustic emission
- Fiber optic
- Soil monitoring
- Ultrasonic flow meters
- Vapor monitoring
- Mass balance
- Real-time transient modeling
- Pressure point analysis

This Chapter also contains the checklist for each threat with the purpose of facilitating the review and compilation of the information required to support the assessment of PoF and consequences during the risk assessment exercise.

The means, actions and methods to show damage and mitigate threats are included as Annexes to this Manual in order to help take action on the probability of failure or susceptibility of damage for each of these threats.

7.1. Internal Corrosion

In oil production, refining and transportation, fluids transported through pipelines usually carry water and pollutants, where the corrosion potential is directly related to its physicochemical characteristics, water/fluid relation and transportation form. In turn, given the geographic characteristics and extension of each country, location of cities, different types of soil relief and hydrographic basins, oil and oil byproducts transportation pipelines present, in addition to large extensions, different routes, dimensions and project requirements. Taking these two items into consideration, it is increasingly necessary to pay greater attention to possible accidents caused by internal corrosion.

It is necessary to develop a master plan to monitor and control the entire process of pipeline internal corrosion, taking into account the control of their integrity and the quality assurance of the product to be delivered to customers.

7.1.1. Description of Threats of Damage Due to Internal Corrosion

Corrosion is the deterioration of material by the chemical or electrochemical action of the medium, and may be associated or not to mechanical stress.

Corrosion may affect different types of materials, whether metallic, such as steel, or non-metallic, such as plastics, ceramic or concrete. This Manual will focus on corrosion of metallic materials. This corrosion is called metallic corrosion.

Depending on the action of the corrosive medium on the material, corrosive processes may be classified in two major groups, which cover all the cases of deterioration by corrosion:

- Electrochemical corrosion (aqueous corrosion)
- Chemical corrosion (high temperature oxidation or high temperature corrosion)

Electrochemical corrosion is more frequent in nature and is characterized basically by:

- The presence of water, in liquid state, of dissolved ions (dissociated cations and anions)
- Working at temperatures below the water dew point, which in most cases is the room temperature
- The formation of a corrosion cell with circulation of electrons on the metal surface, involving partial oxidation and reduction reactions

As the electrolyte needs liquid water, electrochemical corrosion is also called aqueous corrosion.

In corrosion processes, metals react with non-metallic elements or compounds present in the medium, O_2, S, H_2S, CO_2, among others, producing compounds similar to those found in nature from where they were extracted. Therefore, it can be concluded that corrosion in these cases is the opposite of metal refining processes.

As no liquid water is needed in chemical corrosion, it is also called dry corrosion, i.e., corrosion in non-aqueous medium. it usually takes place at high temperatures. These are its characteristics:

- They are oxidation and reduction processes taking place in the same area, directly between the metal and the aggressive medium on the metal. They are less frequent in nature, involving high temperature operations.
- Liquid water is absent; also known as dry corrosion.
- It usually takes place at high temperatures, always above the water dew point.

Inside hydrocarbon transportation pipelines, electrochemical corrosion processes generally occur due to the presence of corrosive agents that dissolve in the liquid water transported and produce oxidation-reduction reactions in the exposed metal.

7.1.2. Types of damage caused by internal corrosion

Forms of corrosion are defined mainly by the appearance of the corroded surface. The main forms are:

- **Uniform corrosion:** When corrosion is processed almost evenly in the entire surface affected. This form is common in metals that do not form protective layers as a result of the attack.
- **Corrosion in layers:** Corrosion products are formed in layers that detach gradually. It is usual in metals that form an initially protective layer, but when they turn thick, they fracture and lose adherence, exposing metal to a new attack.
- **Alveolar corrosion:** Wear caused by corrosion that is localized and has the appearance of craters. It is frequent in metals forming semi-protective layers or when there is under-deposit corrosion, as is the case of differential aeration corrosion.
- **Pitting corrosion:** Wear that is very localized and highly intensive; generally its depth is greater than its diameter and has angled borders. Pitting corrosion is frequent in metals forming protective layers, in general passive, which are destroyed in localized points by certain aggressive agents that become active, thus enabling a very intense corrosion. A common

example is authentic stainless steels in mediums containing chlorides. The presence of microorganisms, such as sulfate-reducing bacteria, also helps triggering and accelerating the localized corrosion process.

- **Intragranular corrosion:** The attack is on the grain boundaries, as is the case of sensitized austenitic stainless steels exposed to corrosive mediums.
- **Transgranular corrosion:** The phenomenon is evidenced by cracks that extend through the interior of the material grains, as is the case of stress corrosion of authentic stainless steels.

7.1.3. Checklist for Internal Corrosion

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST INTERNAL CORROSION TRANSPORTATION SYSTEM							
#	Aspect / Item / Characteristic	Required		Available		Location of data	Comments
		Yes	No	Yes	No		
1.	Are there procedures to determine the severity of the internal corrosion and the identification of the corresponding corrective measures?						
2.	Are there a procedure and program being implemented to run an instrumented pig in order to detect internal corrosion for the case of non-piggable/piggable pipelines? If this is the case, how is the frequency of this inspection established?						
3.	Are there an inspection procedure and program being implemented to determine the loss of internal thickness for non-piggable/piggable pipelines, or for pipelines that do not have the necessary facilities to run an instrumented pig? If this is the case, how is the frequency of this inspection established?						
4.	Are there a procedure and program in place, of internal cleaning and/or removal of water or condensate through the run of pigs? If this is the case, how is the frequency of this activity established?						
5.	Are corrosion inhibitor injection programs (automated pump – controlled dosage – efficiency assay) available for all pipelines, wherever required?						
6.	Have routine tests been implemented to measure the content of water in the products transported? If this is the case, how is the frequency of this activity established?						
7.	Have routine tests been implemented to monitor and analyze the corrosivity of the products transported (corrosive residues, water and gases)? If this is the case, how is the frequency of this activity established?						
8.	Are there procedures and routine tests in place to determine the rate of corrosion by corrosion coupon and/or electric resistance probes? If this is the case, how is the frequency of this activity established?						
9.	Is feedback on the results obtained with testing equipment and fluid and residue tests being provided to the corrosion management system (use of software – trend graphs – change in the variables of preventive measures – identification of the corrosive process)?						
10.	Are there training and rating procedures for the experts working in the corrosion activity?						

Table 2: Checklist for internal corrosion

7.2. External Corrosion

External corrosion is one of the threats to which any transportation pipeline of hydrocarbon or any other hazardous product, whether in liquid or gaseous state, is subject.

This Manual does not intend to address in depth each type of corrosion that may occur in a pipeline. However, it is necessary to list them and present a basic explanation of damage mechanisms, with the purpose of facilitating their identification and establish the most appropriate inspection techniques to make them evident, and the aspects that may be considered for their mitigation.

7.2.1. Description of Threats of Damage Due to External Corrosion

Metal corrosion is the tendency of metals to return to their original stable state as when found in nature (oxides) from where they were extracted. Corrosion is defined as the deterioration or degradation of a material, usually a metal, due to its reaction to the surrounding environment. The rate at which metal is deteriorated or corroded is primarily determined by the environment to which it is exposed and by the preventive measures taken in that site to mitigate the corrosion process.

Almost all types of external corrosion attacks may be listed under several major categories. Perhaps, <u>the strongest characteristic of corrosion is the huge variety of conditions where it occurs and the great number of forms in which it appears</u>. Although there are several different forms of corrosion, each share some common factors. There is electrochemical corrosion if there is:

1. An anode
2. A cathode
3. A metallic conductor connecting the anode and the cathode (typically, the pipeline itself)
4. An electrolyte where chemical reactions are produced and that allows the flow of ions (typically the soil, the atmospheric environment, and tributaries of groundwater or surface water, etc.)

Regardless of the type of corrosion, each of the four above-mentioned elements shall always be present for corrosion to occur. The corrosion control program will consist in eliminating one of the four factors to stop the electrochemical reaction.

External corrosion may occur both in aerial and buried or submerged pipelines. When pipelines are aerial, corrosion likely to occur is atmospheric. The extent of corrosion depends on the climate conditions where the pipeline runs - it is greater in coastal and industrial areas – and on the coatings applied to insulate the metallic substrate from the environment. Aerial pipelines require, in addition to the coating system, an adequate support to avoid direct contact with the soil or watersheds. The pipe-support contact area shall be insulated to avoid leakage of the cathodic protection current, which would reduce the extent of the protection in buried segments.

The aerial-buried pipeline interfaces represent one of the most favorable conditions for corrosion. This is due to the effect of the solar ultraviolet light and exposure to rain to which the coating is subject. The coating usually cracks and detaches, thus facilitating accumulation of moisture between the coating and the metal surface. If this damage mechanism is not evidenced and mitigated early enough, catastrophic failures (ruptures) of pipelines occur.

When pipelines are buried or submerged in water, water usually produces anodic and cathodic areas, which are created by the steel manufacturing process, due to the surrounding environment, other buried facilities, structures transporting direct current, foreign cathodic protection systems, and other factors. The pipeline itself is the metallic conductor, and the soil is the electrolyte.

Normally, external corrosion may be classified as general corrosion or as pitting, which can be localized or general.

Pitting is usually confined to a small area or several interconnected small areas. Localized corrosion or localized pitting may be in the form of individual or multiples pits. Localized corrosion is evaluated using depth and length measurements, which allows the determination of the remaining strength of steel.

Bacteria-induced corrosion, oxygen concentration differentials, erratic interference current, or simply the interaction between galvanic cells may cause localized pits. Localized corrosion causes concern for the integrity of a pipeline, since the area being attacked is very small and the corrosion rate, in some situations, may be extremely high, thus resulting in leakage of the product.

7.2.2. Types of Damage Caused by External Corrosion

The type of corrosive attack that may be found in a pipeline depends primarily on the environment and on the area of the pipeline exposed. Following is a description of the most common types of corrosion of pipelines:

7.2.2.1. Selective ERW Seam Corrosion

The selective ERW seam corrosion, also called preferential seam corrosion, is created when the pipe is experiencing corrosion caused metal loss, either internal or external, across or adjacent to an ERW seam. The corrosive medium attacks the seam bond region (the ferritic line and/or heat-affected zone) at a higher rate than the surrounding metal, as it is an area with more accumulated energy (anodic area). The result of this selective attack is often a V-shaped crevice or groove within the bond line. Selective seam corrosion creates a serious defect that is more likely to cause a rupture than coincident corrosion in the body of the pipeline.

7.2.2.2. Narrow Axial External Corrosion

The narrow axial external corrosion (NAEC) is often found in heat-affected zones of circumferential welds between pipelines and at longitudinal double submerged arc welded seams coated with polyethylene tape. The tape, due to the bulge or excess thickness of the weld seam, leaves a space between the welding metal limit and the base metal; when the oxygen is trapped in this space, it promotes the attack of this area likely to be corroded. In addition, if the tape detaches or wrinkles due to soil stress or because it was deficiently applied, it allows water in and provides an environment favorable to the attack of the HAA which cannot be mitigated through cathodic protection due to the shielding effect of the tape to the current provided by the anodes of the cathodic protection system. The resultant groove-like defect facilitates the axial rupture of the pipe under internal pressure, or cut or detachment between pipelines under flexure stress.

7.2.2.3. Microbiologically Influenced Corrosion (MIC)

Bacteria are found in essentially every soil and water. While some of them do not present problems as far as corrosion of metals is concerned, they are important exceptions. The two basic categories of bacteria are aerobic (oxygen-using) and anaerobic (non-oxygen-using). Both types can be present in the same environment depending on temperature, moisture, nutrient supply, etc. Aerobic bacteria are more abundant where oxygen is plentiful, and anaerobic bacteria are more abundant in oxygen-deficient environments. Members of both groups can contribute to conditions that cause external and internal corrosion of pipelines.

Typically, a number of microorganisms influence the corrosion of ferrous metals significantly. These bacteria are hydrogen-consuming and sulfate-reducing, and are commonly referred to as SRB. They do not directly attack the metal, but cause changes in the electrolyte that increase corrosion activity. Not only do they convert sulfides into sulfuric acid, which attacks the pipeline, but they also consume hydrogen, which destroys the polarization of the passivation film on cathodically protective structures and increases the current requirement for effective cathodic protection.

Anaerobic bacteria are found in stagnant bodies of water, both fresh and salt, in heavy clay soils, swamps, bogs and in most areas that have moisture, organic materials, low oxygen and some form of sulfates.

Aerobic bacteria can also create corrosive environments for buried steel structures when sufficient organic matter is available for a food supply. Various organic acids can be formed depending on the type of bacteria and the available organic material. When bacteria produce carbon dioxide, it combines with the available water to form carbonic acid and ammonia compounds, which are oxidized into nitric and nitrous acid. Other acids that can be formed under the proper conditions are: lactic, acetic, citric, oxalic and butyric, among others.

Aerobic bacteria are known to attack some pipeline coating materials made from organic materials and use them as a food source; these include asphalt coating and primers, tape adhesives, Kraft paper and felts.

Morphology of bacterial corrosion consists of pits or gullies which, depending on their orientation with respect to the pipeline axis, create leaks or ruptures.

7.2.2.4. Galvanic Corrosion

It is defined as corrosion associated with the current resulting from the coupling of two o more dissimilar metals in contact with a common electrolyte. One metal shall be anodic (the anode) and the other cathodic (the cathode). As mentioned above, a piece of steel has cathodic areas and anodic areas (areas with more accumulated energy) due to the level of impurities that may be present in the metal.

These corrosion cells are created when different alloys, such as copper and stainless steel, are in contact with carbon low-alloy steel or a new piece of pipe inserted into an older pipeline, as when pipes are replaced due to maintenance, where the new pipe behaves as the anode. Galvanic corrosion cells can also be created due to different metals used when welding a pipeline.

In addition, galvanic corrosion can also occur if stress is applied to the pipeline, such as stress produced in welded joints, mechanical curvatures in the pipeline, arc burns or metallurgic notches generated when the electrode jumps across the pipeline surface, or in a pipeline that has been scratched during excavations.

The presence of concrete in portions of the pipeline, such as those portions present in the interface of segments with ballast and without ballast, may cause galvanic corrosion. Soils with different chemical composition or significant changes in their resistivity promote galvanic corrosion. An anode and a cathode are present in any electrolytic corrosion (galvanic cell). However, the general theory assigns the category of galvanic corrosion to the galvanic pair (coupling of dissimilar metals).

7.2.2.5. Stress Corrosion - Stress Corrosion Cracking (SCC)

It is a form of cracking produced by the combined effect of electrochemical corrosion and the stress on the pipeline, wherein small cracks lengthen and deepen slowly over a period of years. The individual cracks, which may occur in colonies, may eventually join together to form larger cracks. SCC may be present on a pipeline for many years without causing problems, though once a crack becomes large enough, it could leak or break. Among the factors having influence on this type of anomaly are the age of the pipeline, electrolyte chemical composition, type of coating, levels and conditions of the cathodic protection system, soil stress, type of drainage and pressure cycles.

These factors together with data obtained from excavations, if any, will enable the identification of any susceptibility of the pipeline. Fracture mechanics-based models and the crack growth rate may be used to assess the need and time of inspection if there is stress corrosion cracking in the pipeline.

Three (3) conditions shall be present for SCC to occur: a susceptible microstructure, a corrosive environment and a tensile stress.

- **Microstructure:** All commonly used line pipe steels are susceptible to SCC, though susceptibility may increase with tensile strength.
- **Environment:** Specific forms of SCC are associated with specific terrain and soil types, particularly those having alternating wet-dry conditions, and those that tend to damage or disbond coatings. While SCC may occur in almost all soil types, it may be avoided by isolating the local electrochemistry at the pipeline surface from the surrounding conditions by applying coating. Thus, the type and condition of the pipeline coating are important factors in the mitigation of this damage mechanism.
- **Stress level:** Susceptibility to SCC increases with stress level though there may be no lower threshold stress level. Conducive stress levels may occur at local structural discontinuities, as for example weld toes or sites of deformation due to outside forces, such as dents. Some amount of stress cycling can promote SCC growth by breaking the oxide film that forms on the crack surface, re-exposing the crack to the environment. Cyclic loading seems to be an important factor in the initiation of SCC.

Two forms of SCC have been identified: high pH, called classical, and near-neutral pH, non-classical. The high-pH form tends to occur within a wide cathodic potential range and at a local pH over 9. This is associated with increased pipeline operating temperatures. Cracks tend to be narrow and primarily intergranular. Pipelines with coal tar and asphalt coating are sometimes susceptible to this type of cracking.

Near-neutral-pH SCC tends to occur at a local pH of 5.5 to 7.5; it is associated with mild concentrations of CO_2 in ground water and cold climates. Cracks are generally transgranular, wide and more corroded than those found in high-pH SCC. Generally, tape coated systems are susceptible to this type of environment.

7.2.2.6. Stray or Erratic Current Corrosion

Stray current corrosion, usually in the form of pits, is caused by the influence of external sources of electric alternating currents as those generated by medium and high tension AC lines, and by sources of direct current, such as those produced by foreign cathodic protection systems of pipelines, DC power lines (HVDC or DC generators) or dynamic currents produced by mass transportation systems, such as subways or electric locomotives.

7.2.2.7. Differential Aeration Corrosion

It occurs in the pipeline segments where there are different oxygen concentrations as in the aerial-buried interfaces or in the pipeline segment with supporting structure clamps.

7.2.3. Checklist for external corrosion

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST EXTERNAL CORROSION TRANSPORTATION SYSTEM							
#	Aspect / Item / Characteristic	Required		Available		Location of data	Comments
		Yes	No	Yes	No		
1.	Is the age of all pipeline segments known?						
2.	Is the temperature of the transported product and of the surface along the pipeline known?						
3.	Is there information available on the resistivity of the soil or environment where the pipeline runs?						
4.	Is there information available on the aggressiveness of the soil or environment where the pipeline runs?						
5.	Is there information available on the type of soil or environment where the pipeline runs? (clay, mud, rocks or watershed)						
6.	Is there information on the type of coating for each pipeline segment?						
7.	Is there information available on the condition of coating for each pipeline segment?						
8.	Is there information available on the location and characteristics of the cathodic protection rectifiers?						
9.	Is there information available on the condition of pipeline electric insulation with initial plant, delivery point and final plants?						
10.	Is there information available on the condition of the aerial structure insulation (landmarks, H frames, turnbuckles)?						
11.	Is there information available on the condition of the coating of aerial-buried pipeline interfaces?						
12.	Are the levels of the pipeline cathodic protection (post to post *On/Off* technique or CIPS)?						
13.	Is there information available on the effective real time of operation of CPRs?						
14.	Is cathodic protection monitored according to the frequency stated in the external corrosion control plan?						
15.	Is there information available on the pipeline mechanical condition as a result of running in-line inspection (ILI) tools?						
16.	Have repairs been made as indicated in the ILI being made according to level of severity?						
17.	Have adjustments been made to the cathodic protection as a result of post to post *On/Off* inspection or CIPS?						

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST EXTERNAL CORROSION TRANSPORTATION SYSTEM							
#	**Aspect / Item / Characteristic**	**Required**		**Available**		**Location of data**	**Comments**
		Yes	**No**	**Yes**	**No**		
18.	Have repairs been made to the pipeline coating as a result of visual inspections or DCVG/PCM/ACVG?						
19.	Is the historical record of failures due to external corrosion available?						
20.	Are there training and rating procedures in place for the experts working in the external inspection activity?						

Table 3: Checklist for external corrosion

7.3. Natural Forces

As liquid and gas hydrocarbons transportation pipelines are broad lineal development works, they run through areas with topographic, geological, hydrographic, climatologic and seismic conditions with varied characteristics, behavior and susceptibility. Consequently, they are exposed –in the short and long term- to threats and natural processes after startup of operations and eventually in the construction stage.

The forces of nature, conceived as the set of climatic, meteorological, seismic and hydrological conditions of the geographic area where the pipelines extend, change over time and alter or modify the environment, making the right of way likely to be affected, and causing instabilities and unexpected stress on the pipeline that could break it. Therefore, the pipeline integrity program shall include a plan to address forces of nature, conceived as geohazards, covering the dimensioning of the risk and an appropriate plan of inspection, monitoring and implementation of activities to mitigate the threat.

The construction of a pipeline demands large-scale excavation works, soil movement or removal, and deforestation, which alter and/or modify to a greater or lower extent and magnitude the natural conditions of geotechnical and/or hydrodynamic stability of the route – right of way (RoW) or easement – where the duct runs and its environment. These alterations shall be mitigated during the construction; otherwise, they shall be covered by the pipeline maintenance and operation programs.

For this reason, for proper research, diagnosis and geotechnical interpretation, it is of the utmost importance to properly interpret the local and regional geology.

7.3.1. Description of Threats of Damage Due to Natural Forces (Geohazards)

The occurrence of natural processes (geohazards) is caused by the combination of several factors, some of them acting as determinant factor, as is the case of geomechanical properties of materials (soil and rocks), abrupt topography, location and fluctuation of the phreatic level, and others, such as earthquakes, rain or human intervention as triggering factors of the process. Conventionally, they are classified and characterized as follows:

Those related to hydro-meteorological processes:
- Rainfalls (medium, high or concentrated intensity)
- Snowfalls and thaw

Those related to external geodynamics processes:
- Landslides or slope rocks
- Land creep
- Liquefaction, solifluction and tubification in sandy-muddy soils
- Differential settlements
- Alluviums
- Gullies and erosion caused by surface runoff

Those related to internal geodynamics processes:
- Seismic activity
- Reactivation of local and regional geological faults
- Volcanism (very rare)

Those related to fluvial hydraulics and coastal engineering:

- Riverside erosion and subsidence of the bottom of the river channel (degradation)
- Erosion and/or sediments in marine beaches
- Swells

In the pipeline segments buried in soils with dissimilar physico-chemical composition, corrosive properties, changing electric resistivity, alternating moisture conditions (wet/dry), and/or intersection with chemically deficient or aggressive drainage sources of surface or phreatic water and location on rocky soils, it is necessary to study and assess on a periodic basis the alterations or damage that this type of soils may cause to the external coating, and the efficient behavior of the cathodic protection installed to protect the pipeline against external corrosion.

The geohazards described alter the natural conditions of geotechnical stability of the route - right of way or easement, posing a threat to the integrity of the pipeline, as when geotechnical instability is generated, stress may be caused on the pipeline that may exceed the thresholds of deformation of the same and thus cause its rupture. These may be foreseen with the use of stress concentrators.

The geohazards risk for buried pipelines varies depending on the natural processes existing in the area where the pipelines extend and on the mechanical properties of the pipeline. In this regard, the integrity program related to these hazards shall include the development of inspection and monitoring activities, and the implementation of mitigation actions in both perspectives, from the environment or natural process that causes the disruption of geotechnical stability of the route - right of way and from the element at risk, that is, the pipeline.

7.3.2. Types of Damage Produced by Natural Forces

The effects, i.e. damage caused by these geohazards on the pipeline integrity, are in proportion to the type, extent, form of occurrence in time – they may occur suddenly and violently (landslides and/or slope rocks), while other act gradually (land creep, settlements, etc.) - magnitude (pressure and stress generated) and materials involved in the natural process.

The effects of natural forces produce unexpected stress that causes the plastic deformation of the material; if the deformation generated exceeds the permissible limits associated with the mechanical properties of the pipeline, the pipeline may break.

The identification of sites where the pipeline has been affected is achieved through the correlation of results of inspections with an inertial intelligent tool to detect changes in the trajectory of the pipeline. Where there are movements of the pipeline, the increase in the deformations and the probability of failure shall be assessed in accordance with established thresholds of deformation.

Depending on the location of the pipeline with respect to the vector of effort that is generating the condition of instability, pipeline movements can be classified as transversal (see Figure 5), longitudinal (see Figure 6) or oblique (see Figure 7).

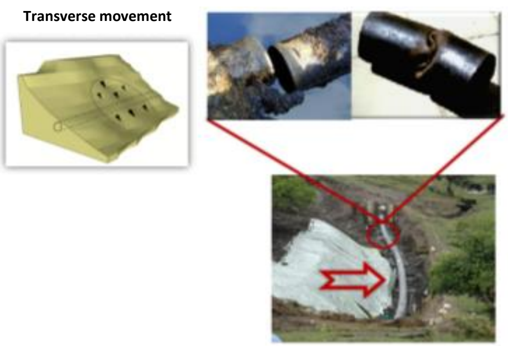


Figure 5: Transversal movement of pipeline

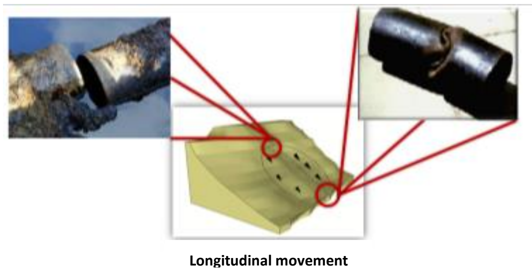


Figure 6: Longitudinal movement of pipeline

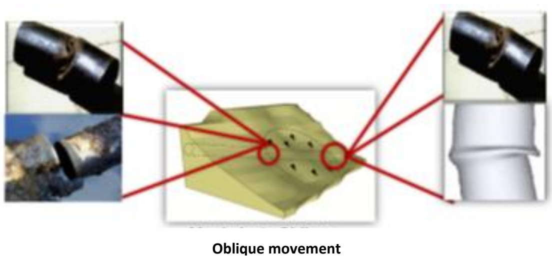


Figure 7: Oblique movement of pipeline

The impact and severity of damage are generally classified as follows:

- Modification and geometry degradation of the right of way
- Destabilization and collapse of the strip of right of way and its environment
- Destabilization of the right of way with geometric pipeline deformation
- Destabilization of the right of way with leakage and/or pipeline rupture (product leakage)

7.3.3. Checklist for Natural Forces

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST NATURAL FORCES TRANSPORTATION SYSTEM							
#	Aspect / Item / Characteristic	Required		Available		Location of data	Comments
		Yes	No	Yes	No		
1.	Are project documents and drawings available according to pipeline works?						
2.	Are there any maps and sketches (topographic, road systems, political divisions, aerial photographs, satellite images, access roads to right of way, right-of-way vegetation, removal of material due to excavation, mining facilities, encroachment of right of way, points of control of spills determining easy access in case of any event, subfluvial crossings or others) about the pipeline route available?						
3.	Does the pipeline have a geotechnical zoning and/or risk analysis?						
4.	Has the information on the design, construction and works done to date been integrated in a geographical information system?						
5.	Have areas subject to natural processes been delimited and has the risk they represent been assessed?						
6.	Is there a physical inspection program for the right-of-way available?						
7.	Has the pipeline been zoned according to seismic sensitivity?						
8.	Is there historical information and data available on the seismic and hydro-meteorological activity in the region where the pipeline runs? (historical record of seismic sensitivity)						
9.	Are coordination meetings with public utilities administrators and populated areas adjoining the pipeline periodically held?						
10.	Is there an updated record of past and current actions taken as regards each threat?						
11.	Is there minimum equipment required to gather field information available? GPS navigator, compass, echo sounders, topographic instruments, others.						
12.	Are drawings, maps, aerial photographs, satellite images of the operating pipeline segments or difficult-to-handle occurrence of natural threats periodically updated?						
13.	Are the results of the record obtained from inertial pigging after mitigation or strain-relieving actions compared?						
14.	Is there information available on location and type of regional geophysical (seismic) and hydro-meteorological stations?						
15.	Is there an in-line inspection plan available with a smart inertial tool that allows the identification and measurement of pipeline movements associated with geohazards from construction?						

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST NATURAL FORCES TRANSPORTATION SYSTEM							
#	Aspect / Item / Characteristic	Required		Available		Location of data	Comments
		Yes	No	Yes	No		
16.	Have admissible and critical unit deformation criteria been established to assess the probability of failure of the pipeline in case of displacement as a consequence of geohazards?						
17.	Is there an inventory of pipeline movements related to geohazards, with their corresponding risk levels?						
18.	Has an action plan and a mitigation plan been defined regarding geohazards, in order to decrease the risk of failure of pipeline and RoW?						
19.	Is there a historical record of the geotechnical, topographic and mechanic monitoring in sites where there is evidence of geohazard-related displacements?						

Table 4: Checklist for natural forces

7.4. Third-party Actions

Third-party actions are another threat to which any pipeline transporting hydrocarbons or hazardous products, either liquid or gaseous, may be subject. These third-party actions, which cause damage to infrastructure (facilities) and therefore, product leakage, may be voluntary or involuntary.

While for facility and for construction and maintenance savings reasons there is a tendency to run pipelines close the roadways, railways, rivers or channels, or populated areas, this implies greater vulnerability to third-party actions, causing increased interaction between the infrastructure and the population involved. Moreover, as human settlements usually develop strategically in places with easy access to goods and services - as facilitated by roads, rivers, railways, etc. -, localizing the layout of pipelines parallel to these means of communication bring about closeness between pipelines and the permanent population in the territory.

7.4.1. Description of Threats of Damage Due to Third-party Actions

This type of threats may be voluntary or involuntary.

- Voluntary are those caused by persons who attack infrastructure, as is the case of blasting or perforating a pipeline to steal the product.
- Involuntary threats are the following: 1 - those caused by persons working in companies that share the right of way and/or easement of the pipeline, such as owners of other pipelines, companies providing other services, such as aqueducts, communications, sewer systems, home gas networks, waterways and roadways, and 2 - housing construction and real estate developments, when excavations are made for maintenance or constructions works, and there is no knowledge of the existence of pipelines in such common pieces of land. This involuntary damage caused by the so-called anthropic factors, due to the construction of urban, industrial, agricultural, road and energy infrastructure, and other type of human intervention near the pipeline, usually increases the susceptibility of the infrastructure and the probability of occurrence of catastrophic events, as well as consequences of the effects on the population and social infrastructure in territories of influence of the operations.

As third-party threats are external to the operation and independent in time, their management implies a co-responsible and synergic work among companies, the state and the communities. In most cases, their regulation and control depend on territorial authorities and state control agencies or institutions. However, infrastructure owner companies and/or operating companies play a fundamental role on aspects related to infrastructure maintenance and know-how about management.

In this regard, in order to ensure the safety of the operations and the harmonic coexistence with the surrounding territory and its inhabitants, it is necessary to work in collaboration, at least regarding the following aspects: 1- interventions that improve infrastructure integrity, facilitate its control and monitoring and improve the capacity of operators to anticipate potential events; 2- agreements on the adequate management of shared RoW; and 3- promotion of assertive management of the territory of influence of the hydrocarbon transportation activity, in order to harmonize activities, soil uses and population density.

7.4.2. Types of Third-party Damage

Third-party actions produce perforations, ruptures, scratches or notches, and dents of pipelines, increasing the probabilities of failure of the infrastructure (facilities). They also increase the potential consequences on populations, their infrastructure and the environment due to loss of containment.

The actions to control, mitigate and determine third-party actions require various methodologies depending on their origin, whether they are caused voluntarily or involuntarily.

7.4.2.1. Dents

Dents are usually produced in starting rupture or crack points, even more so if accompanied by a stress concentrator, such as scratches or notches. Dents may be classified in several types, depending on whether there is an associated stress concentrator or not, and according to their location with respect to the longitudinal or circumferential pipeline weld. In addition, their critical condition and need for repair also depend on their location in the pipe with respect to the clock panel. The assessment and care criteria to be used are those established in the company's procedures or codes or standards stated in the bibliography in Chapter 11.

Following are some types of dents:

7.4.2.1.1. Plain Dents

Plain dents are a local change in the surface, but not accompanied by a stress concentrator, produced by rocks in the filler, tree roots or trunks, or mechanical impact.

7.4.2.1.2. Dents with a Stress Concentrator

This type of defect is a dent with stress concentrator, such as corrosion, cracks, gouges, grooves or arc burns located within the dent. Attacks with explosives and the machines used for excavation or perforation of soils usually cause this type of dents. Dents with stress concentrators should be repaired as soon as possible.

7.4.2.1.3. Double Dents

Double dents consist of two dents that overlap along the axis of the pipeline creating a central area of reverse curvature in the longitudinal direction. Fatigue cracks develop in the saddle region between the two dents and often develop to critical proportions faster than fatigue cracks in single dents.

7.4.2.1.4. Dents Affecting Welds

These are dents affecting longitudinal or circumferential seam welds. Welds themselves represent a stress concentrator. Therefore, when associated with a dent, they represent an increased risk for the pipeline integrity and require immediate attention.

7.4.2.2. Scratches

Scratches are the mechanical removal of metal with well-defined borders, produced by excavation or perforation machinery or transportation vehicles impacting on superficial pipelines, elevation ropes or supports, or by attacks with explosives. These are stress concentrators that shall be assessed and repaired. All scratches exceeding 12.5% of the nominal pipeline thickness shall be repaired or removed. When choosing to grind the pipeline in order to remove the scratch or gouge, it is necessary to check that the remaining pipeline thickness can support the stress produced by internal pressure. Otherwise, the scratch shall be filled up by welding using a qualified welding procedure, install a type B reinforcement sleeve, apply a reinforcement system of compound material or replace the pipeline section. While the repair has not been completed, it shall be assessed whether it is necessary to modify the maximum operating pressure.

7.4.2.3. Arc Burns

They occur when due to negligence, deficient supervision, failure to apply procedures or lack of knowledge, the electrode is dragged on the pipeline surface in works involving welding, or because of deficient grounding. They represent a metallurgic notch, which shall be removed by changing the pipeline section or removing the affected material by grinding. This may be controlled through the application of Nital 5 to 10 after each grinding, until it disappears. In the latter case, the remaining thickness shall be checked with ultrasound to determine whether the pipeline can support the maximum service pressure at that point. Otherwise, it is necessary to fill it up by welding using a qualified welding procedure (WPS and PQR) for such purpose or reinforce it mechanically with type B sleeves, apply a reinforcement system of compound material or replace the pipe section.

7.4.2.4. Illegal Perforations

This type of damage is caused by persons who steal hydrocarbons. They perforate the pipe and install a valve to take out illegally the product transported in the pipeline. The repair of this type of damage requires the application of rubble (patches), type B sleeves, hot tapping and/or replacement of the pipeline.

7.4.2.5. Attacks

This type of voluntary third-party action causes scratches, dents, perforations and/or complete ruptures of the pipeline. Repair of these types of damage require mechanical reinforcement of the pipeline with reinforcement sleeves, or replacement of the pipeline section.

7.4.3. Checklist for Third-party Actions

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST THIRD-PARTY ACTIONS TRANSPORTATION SYSTEM							
#	Aspect / Item / Characteristic	Required		Available		Location of data	Comments
		Yes	No	Yes	No		
1.	Is there adequate knowledge about the level of activity (e.g., populated areas, industrial areas, rivers, routes, etc.) of each pipeline?						
2.	Have points of recurrent voluntary third-party damage been identified?						
3.	Have points of recurrent involuntary third-party damage been identified?						
4.	Is there a historical record of voluntary third-party damage available?						
5.	Is there a historical record of involuntary third-party damage available?						
6.	Is patrolling conducted to detect third-party actions that may threaten the pipeline?						
7.	Is the pipeline route duly identified and signposted in the field? (regular line and areas sensitive to third-party damage, such as crossings and parallelisms with roads and railroads, crossings of water bodies and crossings of populated areas)						
8.	Are there integrated maps of the network of own and third-party pipelines and of facilities of other public utilities companies available?						
9.	Has a single Information Call Center been set up?						
10.	In those areas where third-party actions have been repeated, have exceptional measure been included, such as installing optical fiber or metal cable, usually 30 to 60 cm above the pipeline? Are they continuously monitored?						
11.	Has the pipeline coating depth along the entire pipeline, especially in areas sensitive to third-party damage, been identified?						
12.	Has a public education and awareness program been implemented?						
13.	Is there a program to develop closer relations with state authorities in order to incorporate infrastructure and regulate the development of surrounding areas within the territorial planning and management instruments?						
14.	Has a program been implemented for maintenance of right-of-way and installation of aerial pipelines barriers?						
15.	In those areas where third-party actions have been repeated, have any exceptional measures been implemented, such as additional mechanical protection for the pipeline?						

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST THIRD-PARTY ACTIONS TRANSPORTATION SYSTEM							
#	Aspect / Item / Characteristic	Required		Available		Location of data	Comments
		Yes	No	Yes	No		
16.	In sectors identified as highly sensitive to third-party damage, is the thickness-diameter ratio correct, and is there proper signage of pipeline location and other type of additional protection?						
17.	Have the sites where warning tapes or security fencing were installed been identified?						
18.	Has a written protocol been implemented regarding the right-of-way shared with other pipeline operators, facilities operators and/or service providers?						
19.	Have in-line inspection (ILI) tools been run to determine metal loss?						
20.	Have geometrical calibration tools been run?						
21.	Is there an updated land use plan?						
22.	Have the maps containing pipeline drawings been updated?						
23.	Are there any leak detection systems available?						
24.	Are there any control systems to analyze the reasons for unjustified variations in flow or pressure?						

Table 5: Checklist for third-party actions

7.5. Operational Errors

One of the threats to which the hydrocarbon transportation system is subject is the occurrence of errors during the execution of operations that may result in damage to facilities, hydrocarbon spills, gas leaks and/or specified product contamination.

The geographical extent of facilities and personnel in the various operational units composing the pipeline transportation system makes it necessary to maximize precautions to have all personnel acting in coordination according to common, specific procedures for each event that may occur.

7.5.1. Description of Threats of Damage Due to Operational Errors

The main threat likely to occur in the operation of a pipeline system is the unjustified variation in pressure (negative manometric pressure, sudden increased or reduced pressure, etc.).

These variations indicate that there is a serious problem in the pipeline system and represent abnormal operating conditions that threaten its integrity. In this situation, the problem shall be identified and the response shall be fast and decisive. Otherwise, an emergency could be generated immediately.

Abnormal operating events may generate oscillatory flux and pressure waves known as transient, which may make the pressure exceed the MAOP and/or the MASP (maximum admissible surge pressure) of the pipeline at some of its points, causing its rupture or a decrease in its useful life due to fatigue.

Operational errors can also result in incidents without causing structural damage to facilities, in spills due to overflow of sumps, overflow of tanks, overfill of spheres or product contamination.

7.5.2. Types of Damage Caused by Operational Errors

The following table summarizes the most frequent operational errors and the resulting damage mechanisms:

Operational Error	Failure mode	Effect	Immediate cause	Basic cause
▪ Pipeline startup ▪ Flow change ▪ Tank/sphere changes ▪ Equipment consignment ▪ Overcurrent bypass ▪ Scrapers launching and receiving ▪ Measurement ▪ Dual tank/sphere receiving and pumping ▪ Send pipeline valve closure command (closure in the field or automatic closure)	▪ Pipeline shutdown	▪ High pressure with rupture and spill ▪ High pressure without rupture ▪ Fatigue	▪ Tank/sphere foot valve closed instead of open ▪ Collector valve not opening ▪ Pump release valve closed ▪ Erroneous operation instruction ▪ Automatic sequence failure	▪ Erroneous operation in field ▪ Erroneous remote opening/closure ▪ Lack of preventive maintenance ▪ Lack of training
▪ Receipt at terminal station ▪ Injection of friction reducing chemical agent ▪ Tank/sphere changes	▪ Product contamination	▪ Product outside specification (suspension of delivery of fuel to customers)	▪ Tank/sphere foot valve open instead of closed ▪ Errors in batch arrival estimate (only liquids) ▪ Errors in batch detection (only liquids) ▪ Erroneous instruction from Distribution Center ▪ Instrument error	▪ Lack of preventive maintenance ▪ Task simultaneity ▪ Lack of training
▪ Control of sumps/flares ▪ Scraper installation/removal ▪ Tank/sphere changes ▪ Opening of valves for maintenance or drainage (during normal operation)	▪ Liquid spillage or gas leakage ▪ Overfill of tanks/spheres	▪ Adverse effects on soils and environment	▪ Level meter failure ▪ Level alarm failure ▪ Sump pump failure ▪ Flare pilot failure	▪ Error in tank calibration table ▪ Lack of preventive maintenance ▪ Lack of training

Table 6: Most frequent operational errors

7.5.3. Checklist for Operational Errors

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST OPERATIONAL ERRORS TRANSPORTATION SYSTEM							
#	Aspect / Item / Characteristic	Required		Available		Location of data	Comments
		Yes	No	Yes	No		
1.	Are there mechanical protections in pumps/compressors and plant discharges (PSV and rupture discs)?						
2.	Does the plant have logic protections? For example: shutdown for high pressure, bypass opening, bypass to flare, etc.						
3.	Does the pump station or compressor station have a set point tracking to minimize transient conditions of high pressure?						
4.	Does the pipeline have a global intelligent control strategy of all pump stations or compressor stations in the event of a pipeline shutdown/transient condition?						
5.	Does the pump station or compressor station have emergency shutdown devices in visible and easily accessible locations?						
6.	Are there safety areas in the pump stations or compressor stations?						
7.	Has preventive maintenance of field instruments been planned?						
8.	Is there a smart leak detection system (LDS) to warn of illegal actions and ruptures?						
9.	Is there a SCADA system to set high and low alarms in different TAGs of critical operational variables?						
10.	Does it have a SCADA system which warns through “pop ups” any unplanned change in the process variables?						
11.	In the event of a failure of the SCADA system, are there other options to keep the pipeline operational coordination uninterrupted (external or internal telephone, cell phone, satellite phone, VHF radio)?						
12.	Are check valves in the pipeline periodically tested for correct operation?						
13.	Can high-level alarms in product receiving tanks, sump tanks and spheres be set to avoid overflows? Are these alarms on measuring systems independent from operating systems?						
14.	Are there personnel specialized in incident analysis to learn from errors and experience?						
15.	Are there automatic operations sequences, such as scraper launching/receiving, equipment startup/shutdown, line inflow/outflow of a pump station or compressor station?						
16.	Is there a list available specifying all critical equipment without which the operation is not safe, and, therefore, requires authorization by senior management to continue operations by applying contingency actions that minimize the risk of not having out-of-service critical equipment?						
17.	Is a visual inspection of facilities conducted in each shift change (Checklist for Shift Change)?						

ARPEL REFERENCE MANUAL FOR PIPELINE INTEGRITY MANAGEMENT							
CHECKLIST OPERATIONAL ERRORS TRANSPORTATION SYSTEM							
#	Aspect / Item / Characteristic	Required		Available		Location of data	Comments
		Yes	No	Yes	No		
18.	In the event of low response reliability of valve actuators, is there a field operator who can manually open/close the valves if they fail?						
19.	Is there a methodical, strict operational incident analysis system to determine the basic cause of a failure, and not only the immediate cause?						
20.	Has a dissemination system or forum of lessons learned, errors, accidents or operational incidents been implemented?						
21.	Has an induction and training program been implemented for operators at the time of joining their new job? Are examinations taken?						
22.	Has a training and qualification plan for operators and supervisors of the Distribution Center been implemented?						
23.	Is there a transient condition simulator available to train plant operators and supervisors of the Distribution Center in the correct and quick response to an emergency?						
24.	Are operational emergency drills conducted?						
25.	Do operators and supervisors of the Distribution Center have a thorough knowledge of the maximum pressure values for each pipeline at each point?						
26.	Is there an operation manual and contingency plan available at each pump station or compressor station?						
27.	Is the coordination of pipeline operation centralized in a single control office?						
28.	Is there a written procedure for commissioning and decommissioning of equipment?						
29.	Does the serial number of the plant internal pipes correspond to the maximum operating pressure?						
30.	Is there a robust management and change control system to distribute changes in instructions and facilities properly to all personnel involved?						
31.	Are audits and management inspections conducted to evidence unsafe operating conditions?						
32.	Are multiples identified and signposted?						
33.	Are there updated multiples P&ID diagrams available?						
34.	Are the system HAZOPs updated and implemented?						
35.	Is there a software and/or hardware overpressure protection system that is continuous and automatic and does not depend on any kind of manual intervention?						

Table 7: Checklist for operational errors

7.6. Fatigue

While fatigue has been a well-known phenomenon in engineering for several years, its consideration in transportation pipelines has not been relevant. The standard API 1160 of 2013 mentions the phenomenon by introducing a twelfth threat: "the growth of an initially noninjurious anomaly arising from any one of several of the above causes into an injurious defect via pressure-cycle-induced fatigue"[3]. The ASME B31.4 standard already considered the analysis of fatigue in transportation pipelines, but from the perspective of pipeline design, indicating the requirements for pipelines to resist fatigue.

The threat of fatigue requires pipeline operators to perform validations of their operation periods in order to establish the pressure cycles that are being injurious for the pipeline and may cause the growth of anomalies. Operational checkups not only include the registration of operational information about the systems, but also involve a series of analysis that provide a perspective of pipeline integrity regarding fatigue.

Some analyses to perform are established in other standards:

- ASTM E 1049[4] - This standard states five cycle-counting methods to estimate the number of injurious cycles in pipeline operation, together with the application of an S-N curve. While all methods are accepted by the industry, the rainflow counting method is the mostly used method, as after the analysis performed, this method allows keeping a load history, which is important to consider in the case of fatigue.
- API 579[5] - This standard establishes the steps of fatigue analyses for transportation pipelines, and includes the main mathematical guidelines to determine the effects of most of the fatigue-related anomalies. This standard is important as it summarizes many considerations regarding fracture mechanics in particular applications for the oil and gas industry.

While there are many regulations on this issue, the standards mentioned provide the guidelines regarding fatigue, as they are easy to apply, their results have been checked and they are in accordance with the practices of the industry in our region.

7.6.1. Description of Fatigue Threats

ASTM E1823[6] defines *Fatigue* as the process of progressive localized permanent structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points and that may culminate in cracks or complete fracture after a sufficient number of fluctuations. Based on this, there are three factors that determine fatigue:

- Fluctuating stresses and strains
- Sufficient number of fluctuations (time when fluctuating stresses and strains are applied).
- Cracks, fragile fractures, or a combination thereof

In the case of transportation pipelines, *fluctuating stresses and strains* are those related mainly to changes in internal pressure due to factors inherent in operation, and, equally importantly, due to any other load on the pipelines, and which are variable in time (temperature changes, crosses

[3] Managing System Integrity for Hazardous Liquid Pipelines, API Recommended Practice 1160. Second Edition September 2013. Section 4.2, page 13: "the growth of an initially noninjurious anomaly arising from any one of several of the above causes into an injurious defect via pressure-cycle-induced fatigue (including transit fatigue)"

[4] ASTM E 1049: Standard Practices for Cycling Counting in Fatigue Analyses.

[5] Fitness For Service, API 579 / ASME FFS.

[6] ASTM E 1823, Standard Terminology Related to Fatigue and Fracture Testing.

under railways, river beds, floodable areas, etc.) Each operating company shall establish the load to be monitored for susceptibility to fatigue that it may cause to the pipeline.

As regards the term *sufficient number of fluctuations*, the number of fluctuations shall exceed certain limits for the fatigue process to become critical. This implies, as mentioned above, that the operating companies shall implement an analysis of load cycles that allows them to identify if the critical fatigue time has been exceeded or not, in order to take the pertinent actions. The analyses of standards ASTM E 1049 and API 579 are applicable to this item.

Finally, *cracks* are an indicative sign of fatigue, and they shall be taken into account for integrity assessments. Cracks may appear in healthy metal, but they are more frequent in anomalies and welded joints, as the latter cause an intensification of stress, facilitating the appearance and growth of cracks.

It is therefore necessary to identify which anomalies are more susceptible to the influence of fatigue, in order to determine which are more critical for integrity analyses and further mitigation activities. The classification of threats into time-dependent and time-independent threats constitutes a first checkup. Therefore, anomalies shall be classified according to the threat they represent.

- Time-dependent threats are those tending to grow over time, and therefore, their criticality status also varies over time. Some examples of this type of threats are external and internal corrosion, selective corrosion in welded joints and SCC. Other threats, such as manufacture, construction and mechanical damage threats (i.e., damage not produced by vandalism) may become time-dependent, and each operating company shall establish whether they are time-dependent or not. A fatigue-susceptibility assessment is required in these cases.

- Time-independent threats are those threats that involve fortuitous events, and therefore, it is difficult to relate them with time. Some examples of these threats are equipment failure, mechanical damage (produced by vandalism), incorrect operation, climate and external forces. In these cases, it is necessary to determine whether the anomaly or induced failure is susceptible to fatigue.

8. Action Plans and Maintenance Program

8.1. Action Plans to Mitigate Risks

This stage of the pipeline integrity program arises from risk assessment, and consists in the definition of the techniques and/or methodologies and frequency of inspection, monitoring and mitigation to be applied in order to maintain the integrity of the analyzed segments, as a strategy to minimize the risk. These techniques and/or methodologies are defined based on the critical nature of the threats detected during risk assessment, and on the morphology and characteristics of damage mechanisms, establishing the technical and economic reasons for their use (cost-benefit ratio). Appendix G ("Alternative Actions for Control and Mitigation of Threats – Acceptable Repair and Prevention Methods") is a guide to select monitoring, inspection and mitigation activities for each threat. In addition, Appendices A, B, C, D and E provide options to determine, control and mitigate the damage produced by each threat.

Some of the techniques and/or methodologies that are commonly used to monitor, inspect and/or mitigate each threat and their consequences are the following:

Monitoring and mitigation of internal corrosion:

- Monitoring of internal corrosion (such as the installation of coupons and electric resistance probes) and solids suspended in water from tank drainage (physicochemical analysis of water or sediments related to the transported product, pH, chlorides, H_2S, bacteria, Langelier index, CO_2, electrochemical test, etc.)
- Installation of pipeline cleaning scraper traps
- Removal or drainage of dead legs (sites where water and sediments concentrate in the pipeline)
- Adjustment of filtering systems
- Establishment and execution of a pipeline interior cleaning program
- Establishment and application of a chemical treatment (biocide, inhibitor, oxygen sequestrator)
- Establishment and application of a tank drainage program
- Establishment, if possible, of turbulent flow pumping systems
- Application of ICDA methodology
- UT Scan B and C in selected points for periodic measurement
- Run of in-line inspection tools, such as MFL or UT, to determine metal loss

Monitoring and mitigation of external corrosion:

- Assessment of aggressiveness of soil (type of soil, pH, chlorides, bacteria)
- Continuous resistivity study
- Periodic assessment of cathodic protection rectifiers
- Assessment of cathodic protection post-to-post potential (instant *On/Off* potential), trailing-wire tow-fish method, BFL (bottom towed lateral field gradient), ROV, etc.
- Study of attenuation models to evaluate submarine pipelines
- Determination of cathodic protection levels by CIPS
- Electrical insulation of plants, delivery points and aerial structures, including valves and bridges
- Installation of remote monitoring units in the cathodic protection system
- Reinforcement and/or reinstatement of the cathodic protection system
- Determination of the coating condition by DCVG, PCM or ACVG
- Study of AC/DC interference with other structures and cased crossings
- Mitigation actions for electrical AC/DC interference with other structures
- Inspection and coating of aerial-buried pipeline interfaces
- Visual right-of-way inspection
- Monitoring and follow-up of the increase in the anomalies reported by ILI

- Execution of mechanical repairs as determined by ILI
- Guided wave inspection of pipelines
- Replacement of pipelines
- Replacement or reinstatement of anticorrosion coating
- Replacement or reinstatement of thermal insulation coating

Monitoring and mitigation of natural forces:

- Geotechnical diagnosis and/or monitoring of pipelines (visual and instrumental)
- Protection and stabilization of pipelines in crossings of watercourses (rivers, streams, floodable areas, etc.)
- Comprehensive evaluation of special aerial and sub-fluvial crossings, tunnels, etc.
- Execution of works to ensure the geotechnical stability of the pipeline and any special subfluvial and aerial crossings
- Right-of-way clearing and cleaning
- Diagnosis and installation of protection against electrical discharges
- Construction of bypasses
- Construction of subfluvial and aerial crossings, tunnels, etc.
- Periodic visual right-of-way inspection (aerial and land inspection)
- Availability of georeferenced maps of the pipelines
- Run of inertial and geometry tools
- Identification and characterization of geotechnically-sensitive areas
- Stress relief excavations
- Inspection with smart tool to update information related to the geometry of the pipeline and determine areas where the pipeline is exposed to deformation
- Specific geotechnical inspections or visits

Monitoring and mitigation of third-party actions:

- Update of pipeline plans and maps with GPS
- Patrolling for surveillance and control of illegal activities and right-of-way conditions
- Social management programs in the communities surrounding the pipeline
- Pipeline signposting or marking
- Public education program
- Emergency call information systems
- Information Call Center to locate facilities
- Optical or ground intrusion electronic detection
- Increased depth of cover
- Right-of-way maintenance and control
- Additional mechanical protection to prevent illegal actions, vandalism and terrorism
- Establishment and implementation of a shared right-of-way protocol
- Establishment of adequate thickness-diameter ratios
- Installation of marker tape or warning mesh over pipeline
- Periodic right-of-way inspections
- Run of in-line inspection tools for geometry and metal loss determination
- Leak detection systems
- Control logics regarding flow and pressure

Monitoring and mitigation of operational errors:

- Maintenance and calibration of block valves
- Preventive maintenance of block valves, flanged joints, accessories and vacuum relief valves
- Implementation of maintenance routines for the plant operational control system

- Establishment and development of training plan for operators and maintenance staff
- Certification of operators and maintenance staff skills
- Development, update and compliance with instructions and operational procedures
- Development, update and compliance with Duties and Responsibilities Manual
- Update, development and availability of P&IDs in the operations rooms of the dispatch and reception plants
- Use of HAZOP or any other methodology to determine and mitigate the operational risks of the system
- Implementation of remote system monitoring and operation
- Implementation of audits to the management system
- Signposting and identification of flow lines and accessories in plants
- Register and investigation of unplanned events
- SCADA systems to control centralized operation
- Leak detection systems
- Control logics regarding flow and pressure
- Emergency shutdown systems (ESD)

Monitoring and mitigation of fatigue:

- Corrective actions: Actions aimed to correct anomalies with high probability of failure, according to risk analysis. This is evident when the risk level is high or very high, the crack or anomaly susceptible to fatigue is not fit for continued service, the crack or anomaly susceptible to fatigue must operate at pressure values lower than those of the current operation of the system (not necessarily the MOP), or the time of intervention, inspection or reassessment is less than the period of reinspection established by the operating company. Some corrective actions to be considered by the operating companies are:
  - Change of affected segment
  - Use of temporary repair methods
  - Decrease in operation pressure (considering fluctuations)
  - Suspension of pipeline operation
- Preventive actions: Actions aimed to prevent defects where the fatigue risk analysis shows failures in periods longer than the period of reinspection of the system. Each operating company shall establish the threshold or risk category exceeding which anomalies shall be reported. Generally, this is evident when the risk level is medium, the crack or anomaly susceptible to failure is fit for continued service for at least one year but less than five years, the crack or anomaly susceptible to failure shall operate at pressure values lower than those of the current operation of the system (not necessarily the MOP) during one year but less than five years, or the time of intervention, inspection or reassessment is more than one year but less than five years. Some preventive actions to be considered by the operating companies are:
  - Decrease in operation pressure (considering fluctuations)
  - Mechanical repair of the affected section
  - Direct reinspection of the crack or anomaly susceptible to fatigue

- Predictive actions: These actions are aimed to predict the occurrence of anomalies susceptible to fatigue. This is evident when the level of risk is low, the crack or anomaly susceptible to fatigue is fit for continued service but the level of risk is higher than low (because it is located in high consequence areas), or the crack or anomaly susceptible to fatigue shall operate at stable pressure values. Some predictive actions to be considered by the operating companies are:
  - Having the properties of the fatigue-related material determined by specialized laboratories. These results will help reduce the uncertainty of the analysis.

- Gathering readings of pressure and temperature, and detect flows at smaller intervals to identify sudden changes of the same
- Controlling the growth of anomalies of time-dependent threats through operating procedures to reduce the impact of the pressure and the fluctuation.

- Reinspection intervals: A reference parameter to set the interval of reinspection is an analysis that takes into account the growth of the anomalies that are susceptible to fatigue in a minimum period of five years. At any date before the five-year period when there is an anomaly not fit for continued service, or the level of risk is high or very high, an additional cost/benefit analysis shall be undertaken to indicate optimally if reinspection shall be performed at an earlier date, in order to determine the estimated dimensions of the anomaly, or the intervention of the affected section prior to the date of non-acceptance to continue in service. If the analysis does not indicate any inspection intervals, each operating company shall consider its own inspection interval, which shall be no longer than five years, unless an engineering study, an uncertainty study and a cost optimization study support longer inspection intervals.

To mitigate the consequences:

- Establishment, update and dissemination of contingency plans
- Implementation of contingency plans
- Installation of systems to detect product leakage
- Installation of motorized and remote check valves and/or block valves
- Implementation of emergency shutdown systems (ESD)

To determine pipeline integrity:

- Visual inspection and assessment of indications in aerial pipelines
- Performance of pressure tests
- Application of ECDA and ICDA methodology for corrosion threats
- In-line inspection of pipelines with smart vehicles: geometry, inertial mapping, metal loss and cracks
- Inspection point control (soil, plungers, ROV)

The action plan not only considers the actions related to the determination and mitigation of damage mechanisms produced by threats, but also the mitigation of the consequences of a leak or spill. It also includes the actions required to determine pipeline integrity at different periods to be defined by each pipeline operator, depending on the conditions, history and particular characteristics of each transportation system.

The action plan includes the activities to be performed, the period when they shall be performed and the corresponding costs.

8.2. Risk Reassessment and Changes to the Action Plan

Risk assessment is not a one-time event and there should be an established process to repeat the risk assessment at some operator-defined frequency. Risk assessment should be a continuous process, which is more effective if fully integrated into the daily operations of the pipeline operator. As the monitoring and inspection activities established in the action plan are carried out, more and better information is obtained about the pipeline conditions. In addition, if mitigation actions are applied duly and timely, the risk level concerning probability of failure and consequences shall improve.

The continuous search for new risk diagnosis, assessment and mitigation technologies shall be a priority for pipeline operators. Some of the technologies to consider are those related to pipeline design and construction, monitoring and inspection of damage mechanisms generated by each threat, determination of pipeline integrity, prevention or mitigation of threats, pipeline repair and/or reinstatement methods, risk assessment methodologies and information integration and management tools. These technologies shall be evaluated and incorporated into risk assessment exercises and action plans.

As tools for integration of data collected from monitoring, inspection and mitigation actions are used, it is possible to review the effectiveness of the action plans designed and to perform any required changes, thus establishing a higher level of reliability of the risk assessment methodology and of the expected results of the pipeline integrity program.

Some of the factors that make risk reassessment necessary are: results of inspections or monitoring considered in the initial action plan, changes in pipeline operating conditions, change in the type of product to be transported, new technologies for threat and consequence diagnosis and mitigation, new high consequence areas or major accident areas, the occurrence of events not considered initially, and change to risk assessment methodology, among others.

By performing new risk assessment exercises, the operator gains knowledge and confidence in the desired results.

8.3. Managing Change in a Pipeline Integrity Program

Once a pipeline integrity program is established - based on the initial risk assessment - and during its application, it is important that such program be continuously monitored to integrate the changes made to the pipeline transportation system into the database. Changes in pipeline operating conditions (for example: pressure, flow, temperature, physicochemical characteristics of the product, changes in existing procedures or addition of new operational procedures, others); pipeline physical characteristics (for example: addition of new pump units, a new control system, shared right-of-way with third parties, changes in the type of material, thickness and diameters, variables, installation or removal of block or check valves, etc); changes in service (for example, from gas pipeline to oil pipeline, from system dedicated to a single product to multipurpose pipelines); new high consequence areas or major accident area; restarting systems or equipment that have been out of service for an extended time; changes in land use; and new decrees and regulations that may imply changes in the integrity program, action plan, and/o require a new risk assessment.

It is important to anticipate such changes. For this purpose, it is necessary to have procedures and/or instructions that allow the operator to evidence, study and document the impact of such changes on all stages of the pipeline integrity program, including the review and redefinition of high consequence areas or major accident areas, different damage mechanisms derived from threats, consequences, action plans, and management indicators.

9. Mechanical Integrity Assessment

On the basis of the risk assessment, a mechanical integrity assessment of the pipeline shall be performed where the threats and their consequences were determined using structural integrity assessment methods.

First of all, the best pipeline integrity assessment method shall be determined, as all methods present limitations that are to be taken into account. In some cases, more than one method may be necessary to assess all the threats to pipeline integrity.

9.1. Integrity Inspections

The most commonly used integrity assessment methods are hydrostatic tests, instrumented pigs and direct assessment.

9.1.1. In-line Inspection (ILI) Tools

One pipeline integrity assessment method is the internal in-line inspection of the pipeline. There are different in-line inspection technologies for different types of defects. When internal inspection is selected to assess the integrity of a pipeline segment, the inspection shall be carried out using the adequate technology to determine the anomalies that the operator believes there may be in a specific pipeline. Multiple inspection performed using different tools can be more beneficial than a single inspection carried out with a single tool to determine defects and anomalies.

In-line inspection tools are only available for certain diameters, so it is impossible to use them in certain pipeline segments, such as bypasses. Alternative inspection tools or pressure tests shall be considered to inspect the integrity of those segments.

The accuracy and reliability of in-line inspection tools vary according to each tool, pipeline conditions and other factors. When running an in-line inspection program, the operator shall evaluate whether the inspection tools available are suitable for the desired application, and develop a plan to validate the results. Sufficient inspection excavations shall be performed to prove that the tool is accurate and reliable. Only in this way can the operator rely on such tool to find critical anomalies to be eliminated or repaired.

The metal loss tools currently available in the market are based on the principle of magnetic flux leakage with standard resolution or high resolution. These tools use permanent magnets or electromagnets to induce a magnetic field axially oriented in the pipeline wall when the tool is going through the pipeline interior. The magnetic flux leakage is measured by sensors from the pipeline wall to the pipeline interior, and any flow density deviation is recorded.

Such deviations indicate a change in pipeline thickness or other anomalies that disrupt the magnetic field, such as ferrous materials near the pipeline. This is an inferential method, as the characteristics of the anomalies shall be inferred from the flux leakage. There are certain limitations to the determination and to the ability to quantify the longitudinally oriented metal loss. MFL tools with standard resolution are different from those with high resolution because the latter have more sensors with smaller space between them to measure deviations in the magnetic field, which allow them to collect and store more precise longitude and depth data for each anomaly. Using calculations of remaining strength in corroded areas, the data provided by MFL tools can be used to determine the approximate remaining strength of the pipeline. High resolution tools can also determine if a corrosion anomaly is internal or external to the pipeline wall. There are limitations to the determination of longitudinally oriented metal loss using this technique.

There are also ILI tools to determine the metal loss based on the ultrasound (US) principle. Ultrasonic corrosion tools work by using transmit/receive transducers to transmit an ultrasonic pulse into the pipeline wall and record the number of reflections from both its internal and external surfaces, allowing for direct measurement of the wall thickness and internal/external defect discrimination.

Ultrasonic tools provide direct and linear measurement of wall thickness that can be used to approximate fairly the remaining strength of corroded pipe. These tools have the advantage of being a more direct description of an anomaly as compared to the magnetic flux tool, which is an inferred measurement of an anomaly. With an ultrasonic tool, it is critical that the signal be acoustically coupled to the internal diameter (ID) of the pipeline. This can be a problem for certain paraffinic crude pipelines and with some liquids with inadequate ultrasonic properties, such as ethanol. With the immersion technique, the US tools may be less susceptible to the acoustic coupling difficulty, as no direct contact of the probes with the internal wall of the pipeline is required. US tools are not applicable in gas pipelines, as gas is not a coupling vehicle enabling the propagation of ultrasound in the pipe wall.

In-line inspection tools have been developed to determine longitudinally oriented cracks and discontinuities similar to cracks, such as stress corrosion fractures, long cracks along the seam, selective corrosion of ERW seam or narrow axial external corrosion (NAEC). These tools use shutdown ultrasound waves or circumferential (transversal) magnetic flux technology.

As these in-line inspection technologies to determine metal loss and cracks are improving rapidly, it is advisable to do some market research in order to know the latest solutions in this field.

It is also advisable to have direct and permanent contact with the developers and providers of ILI services, in order to select the best alternative to determine the type of corrosion in each pipeline or segment. Some cases might require the combination of several tools to determine all the types of damage in the pipeline.

In order to perform the instrumented pig inspection, it is necessary to know the pipeline specifications and restrictions (radius of curvature, segment lengths, reductions of diameter, fittings and valves, among others).

9.1.1.1. Considerations for Selection of the Instrumented Pig Suitable for Inspection of Pipelines

The choice of the type of instrumented pig shall be made depending on the types of threats identified in the risk assessment, so that the pig is the most suitable instrument to detect and measure all the anomalies. In some situations, it may be necessary to combine more than one type of instrumented pig to achieve the desired result.

a) MFL Instrumented Pig

The magnetic pig can be used in pipelines carrying oil, derivatives, gas or products in multiphase flow. The measurement of thickness loss is given as a percentage of the wall thickness (indirect measurement). Poor cleaning affects the result of an MFL pig inspection less than the result of an ultrasonic pig inspection.

a.1) Conventional MFL Pig (Longitudinal Magnetic Field)

This type of pig is appropriate to detect:

- Defects of loss of thickness with circumferential orientation
- General loss of thickness
- Small pittings
- Anomalies near the circumferential weld

a.2) Transverse MFL Pig (Circumferential Magnetic Field)

This type of pig is appropriate to detect:

- Defects of loss of thickness with longitudinal orientation
- General loss of thickness
- Small pittings
- Anomalies near the longitudinal weld

a.2) Helical MFL Pig (Circumferential Magnetic Field)

This type of pig is appropriate to detect:

- Defects of loss of thickness with longitudinal and circumferential orientation
- General loss of thickness
- Small pittings
- Anomalies near the longitudinal and circumferential weld

b) Ultrasonic Instrumented Pig

Ultrasonic pigs shall be used to inspect homogeneous paraffin-free liquid pipelines. The quality of the inspection is directly related to the cleaning of the pipeline, and the measurement of thickness is done directly.

b.1) Ultrasonic Pig for Loss of Thickness

This type of pig is appropriate to detect:

- General loss of thickness
- Dual lamination defects, blistering and hydrogen-induced cracking (HIC)
- Loss of thickness caused by abrasion

b.2) Ultrasonic Pig for crack detection

This type of pig is appropriate to detect:

- Longitudinal cracks and circumferences
- Stress corrosion cracking
- Absence of fusion
- Absence of penetration
- Laminations

Regardless of the type of pig chosen for inspection, it is important to consider the following:

- The pigging operation shall be carried out under a speed, temperature and pressure consistent with the specification submitted by the pig manufacturer.
- The cleaning of the pipeline shall be consistent with the technology to be used.
- The operator must know the minimum radius of curvature in the pipeline and other constraints to prevent the pig from getting stuck.

- Minimum and maximum thickness of the pipeline wall, so that the pig can measure the defects.
- Measurement accuracy depends on the type of technology used (MFL/US).

c) Geometric Pig

Inspection with a geometric pig provides information about the dimensions of ovalizations and dents, both in and outside the welding, to assess the structural integrity of the pipeline and determine whether the pipeline is fit for inspection with other instrumented pigs.

High-resolution geometric (mechanical) pigs enable to know the actual thickness of pipelines.

d) Mapping Unit

Pipeline mapping inspection is performed by measuring the tridimensional route with a module equipped with an inertial measurement unit (IMU). This module is used in association with an inspection tool (magnetic, geometric, or ultrasonic).

It is used to obtain precise geographical coordinates for any point along the pipeline, and the accuracy will depend on the accuracy of the referencing of Earth.

This unit is appropriate to:

- Georeference the pipeline, the anomalies and all pipeline accessories. These data are suitable for any type of GIS.
- Perform mapping programs to compare and assess the displacement of lines.

9.1.2. Assessment of Defects Reported by Instrumented Pigs

The evaluation of the report of instrumented pigs regarding loss of thickness, ruptures and geometric data depends on several factors, such as defect assessment methods, type of technical inspection (longitudinal MFL, transversal MFL, ultrasonic, etc.), quality of the inspection, knowledge of the failure mode of the pipeline, historical pipeline operation; experience and training of the evaluator, guidelines of the operating company, etc.

The following actions shall be taken before beginning the evaluation of the report of instrumented pigs:

9.1.2.1. Preliminary Assessment of the Quality of the Report of the Instrumented Pig

- Check if the pigging direction is correct.
- Check if the pipeline extension is correct.
- Check if the thicknesses are consistent with those in the pipeline project.
- Check if the level of magnetization of the MFL pig is adequate.
- Check if the speed of the pigging is within the limits of the tool.
- Check if the loss of signal is within acceptable limits.
- Register the history of correlations and check if the thickness loss measurements indicated by the pig are appropriate, comparing points already inspected and preferably already treated (external metal loss with coating already repaired).
- Check if the pig turned along the pipeline during the pigging operation.
- Check if the odometer presented problems of stagnation or slippage, comparing the distance between the valves reported by the pig and the actual distance.

9.1.2.2. Registration of Pig Limitations and Definition of the Precision and Accuracy to be Considered in the Assessment

It is necessary to know the limitations of each inspection technology by instrumented pig (conventional/transverse MFL and ultrasonic). In addition, it is important to consider the accuracy of the pig for the loss of thickness, size and length of the defect, depending on:

- The technology used in the inspection (conventional MFL, transverse MFL, ultrasonic)
- The diameter of the pipeline
- The pipeline manufacture process (no seam, welding by longitudinal submerged arc or longitudinal welding by electrical resistance)
- The type of anomaly, for example: pitting, alveolar, general, circumferential groove or longitudinal groove
- The dimension of the defect
- The location of the defect in the pipeline (away from, near to or in the weld).
- The pipeline cleaning conditions
- The inspection pig rate
- The defect sizing obtained by manual assessment
- The defect sizing obtained by automatic assessment

9.1.2.3. Historical Record of Pipelines, Main Modes of Failure and their Potential Causes

a) **Time-dependent**
- Internal corrosion
- External corrosion
- Stress corrosion

b) **Stable**
- Manufacturing defect of the pipeline
- Construction and assembly defect

c) **Time-independent**
- Defect caused by a third party (mechanical damage)
- Damage caused by environmental forces
- Human failure

9.1.2.4. Record of Project Data and Pipeline Operation

- Pipeline start point, end point, length
- Diameter, thickness, material and manufacturing process of the pipe
- External and internal coating
- Cathodic protection system
- Project temperature
- Project pressure
- Class of location
- Project standards used
- Year of start of operation
- Products transported
- Operating temperature
- Class of pressure of equipment and accessories
- Coating condition

9.1.2.5. Record of Unique Areas of the Pipeline Route

The following pipeline segments shall be identified during pigging inspection:

- Main routes of submerged segments (rivers, lakes, bays)
- Aerial segments
- Main railway and road crossings
- Environmental preservation areas
- Areas of high population density and industrial concentration
- Horizontal and vertical tunnels

9.1.2.6. Record of Data of Hydrostatic Test

The design of the hydrostatic test, with the profile and the gradient of the hydrostatic test of the pipeline shall be available. The maximum allowable operating pressure (MAOP) at each point of the pipeline is estimated by using the following form:
MAOP = Pressure test/F

Oil pipelines:

- Pipelines constructed according to ASME B31.4
  F= 1.25

Gas pipelines:

- Pipelines constructed according to ASME B 31.8, version prior to 2010
  Class 1 F = 1.10
  Class 2 F = 1.25
  Class 3 F = 1.40
  Class 4 F = 1.40

- Pipelines constructed according to ASME B 31.8, version 2010 and later
  Class 1 F = 1.25
  Class 2 F = 1.25
  Class 3 F = 1.50
  Class 4 F = 1.50

9.1.2.7. Record of Pressures to be Considered in the Assessment of Defects

- Nominal pressure
- Project pressure
- Maximum allowable operating pressure
- Required pressure

9.1.3. Assessment of Immediate Integrity of Anomalies Reported by Instrumented Pigs

The assessment of the anomalies reported by instrumented pigs shall be performed by using internationally recognized standards, such as ASME B31.4, ASME B31.8, and BS7910, among others.

In the case of corrosion defects, an assessment by levels of complexity is recommended, either using the pressure considered at each point of the pipeline, or by different methods of calculating the allowable pressure for the defect. The basic idea of this activity is to perform a conservative initial assessment and, subsequently, adjust it and minimize the number of repairs.

The assessment by levels of complexity shall follow the order shown below:

a) Pressured considered at point

Nominal pressure
Project pressure
MAOP depending on hydrostatic test
Required pressure

b) Methods of calculating reduced pressure

- Level 1
  - ASME B31G
  - 085dL
  - DNV RP-F101 single defect

- Level 2
  - Actual area
  - DNV RP-F101 complex shaped defect

Note: The defects whose compressions in the circumferential direction are higher than those in the longitudinal direction shall also be assessed using Kastner's method.

c) General considerations

Whenever possible, the root causes of defects shall be recorded and actions shall be suggested for their elimination or mitigation.

The information of the various types of inspection performed included in the instrumented pig inspection results is crucial to the analysis of the structural integrity of the pipeline.

9.1.4. Assessment of Future Integrity of Anomalies Reported by Instrumented Pigs

An assessment of the future integrity of the pipeline shall be performed using the pig inspection data and considering the growth rate of any corrosion and cracking defects and the fatigue for anomalies subjected to pressure cycles, so that the pipeline may operate safely until the following integrity assessment (which is performed on the basis of a new pig inspection, of a hydrostatic test or of any other method).

After the immediate and future integrity analysis, a response plan shall be established to maintain the structural integrity of the pipeline by defining the types of repairs to be carried out and the deadlines for their implementation.

9.1.5. Pressure Test

The pipeline pressure test with product or water has been accepted for a long time as a method to determine the pipeline integrity. It is very complicated to carry out hydrostatic tests to pipelines in operation, because such operation shall be interrupted and it is difficult to get the permits required to obtain, treat and dispose of water that might have been contaminated by the transported product. The performance of such tests with product entails a risk of pipeline failure, with the consequential environmental pollution.

However, the hydrostatic test is still an alternative for the operator to check pipeline integrity if it is not possible to run an ILI tool through the pipeline, if the history data about the pipeline segment show that there have been anomalies undetectable with ILI internal inspection tools, or if inspection with other methodologies is not sufficiently reliable as regards pipeline integrity. The hydrostatic test validates the maximum operating pressure of the pipeline. The pressure test shall be performed according to international, national and/or corporate technical regulations applicable to the operator of the pipeline.

The pressure test is a valuable tool to eliminate critical defects. Not all anomalies shall be eliminated during the pressure test, as it only detects anomalies of critical size. These critical defects include the loss of thickness of the pipeline wall due to general or localized corrosion where the axial component of damage is important, as in SCC, ERW or NAEC.

The pressure test is not as efficient to identify localized corrosion. The localized pits may support a high failure pressure due to the restriction around the pit and depending on the pit size. Unless the corrosion depth is enough as to finish consuming the whole pipeline wall by the time of the hydrostatic pressure, the pipeline will resist. Any pipeline with localized pitting may resist a pressure test and maintain the MOP until there is a leak.

The pressure test may increase wall-thickness loss by corrosion and the growth and/or interconnection of cracks while the test shows no failures. Additionally, the corrosion defects and existing cracks might continue increasing over time, so in order to prevent future service failures, it is necessary to continue performing pressure tests at adequate intervals to eliminate the defects that have increased over time or to check that there are no critical defects, before these may reach a condition that allows any unexpected release of the transported product.

9.1.6. Direct Assessment Methodology (DA)

9.1.6.1. ECDA Methodology

This methodology consists in evaluating the parameters that affect and control the occurrence of external corrosion, such as soil resistivity, physical, chemical and microbiological features, CIPS technique, DCVG technique, ACVG or PCM techniques, and other characteristics of the pipeline and the soil where the pipeline is installed, in order to select the area where corrosion can occur and then perform excavations for direct inspection of the condition of the pipeline.
External corrosion direct assessment consists of the following four steps:

1. Pre-assessment: Consolidation of the data mentioned above, defining the feasibility of the application of the ECDA, by selecting indirect inspection tools and identifying ECDA areas.

2. Indirect assessment*:* Indirect measurements of inspections, identification of data, alignment and comparison, definition and application of criteria to classify the severity of the evidence found, comparison of the evidence found and comparison of evidenced data with pre-assessment and historical data.

3. Direct examination*:* Performance of excavations and collection of data, registering damage to coating and measuring the metal loss. The remaining strength of the pipeline in the areas where defects are found is evaluated, a root cause analysis is performed and coating defects are reclassified and prioritized.

4. Post-assessment*:* Calculation of the residual life of the pipeline, establishment of new inspection intervals, evaluation of the effectiveness of the ECDA, establishment of additional criteria to determine the effectiveness of the ECDA, feedback and continuous improvement.

There are areas where it is difficult to apply the ECDA methodology, and this could, therefore, determine its feasibility. These areas are: sectors with cathodic protection coating, sectors with rock filling, paved or concrete areas over the pipeline, areas where it is impossible to obtain data for a certain period of time, areas with buried metal structures near the pipeline, and, of course, inaccessible areas.

9.1.6.2. ICDA Methodology

This methodology consists in a continuous and structured process to improve metal pipeline integrity through the assessment and reduction of the impact of the threat of internal corrosion.

This process consists in the prediction and detailed inspection of the areas where water accumulation is most likely to occur, and therefore, the risk of internal corrosion is considerable.

The guidelines of international standard NACE SP0208-2008 “Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines” shall be considered for the implementation of this methodology.

The development of the ICDA process in pipelines covers the following sub-activities:

1. Pre-assessment: Collection of historical and current data to determine the feasibility of applying the ICDA methodology, definition of ICDA regions and selection of indirect inspection tools.
The following analyses shall be performed at this stage, as a minimum:

- Feasibility of implementation of the ICDA methodology in the system under study
- Definition of ICDA regions

2. Indirect assessment: Identification and definition of areas where internal corrosion may have occurred or may be occurring.

The following activities shall be performed:

- Calculation of angles of elevation associated to the tilt profile of the pipeline
- Flow modeling
- Identification and selection of points where internal corrosion is most likely to occur (or has already occurred)

It is necessary to detail the criteria for selecting the points where direct inspection activities shall be performed.

Analysis and assessment of the probability of internal corrosion in the previously identified points, considering the application of models for the prediction of corrosion and/or amply justified engineering considerations

3. Direct examination: Exposure of the surface of the pipeline at the points selected during the previous activity, in order to take non-destructive measurements and collect relevant data to assess internal corrosion.

The following activities shall be performed at this stage:

- Selection of optimal non-destructive methods to be implemented in the field. In all cases, methodologies accepted and recommended by international standards shall be selected.
- Performance of interventions and non-destructive testing at each point selected for this purpose and at points selected to validate the indirect inspections.

- Analysis of results of the evaluations carried out in the field.
- If defects due to internal corrosion (o due to other mechanisms) are detected, the remaining strength shall be estimated according to the guidelines presented in international standards such as ASME B31G, RSTRENG, DNV PR-F101.

4. Post-assessment: Development and proposal of methodologies to be used to perform the following activities:
- Evaluation of ICDA process effectiveness
- Estimation of remaining life (applicable if internal corrosion defects were identified during the preceding stage)
- Definition of reassessment intervals
- Recommendations of continuous improvement for future ICDA processes

9.1.6.3. SCCDA Methodology

This methodology consists in an analysis and classification of pipeline segments based on their susceptibility to stress corrosion cracking.

A mapping of SCC-susceptible soils is developed based on critical analysis. This will enable to:
- Classify and segment pipelines for different risk levels regarding the threat of stress corrosion cracking.
- Classify the susceptibility of pipeline segments, according to stress corrosion cracking phenomena, into the following classes: Class 1 (high susceptibility), Class 2 (medium susceptibility), Class 3 (low susceptibility) and Class 4 (no susceptibility).

The pipelines shall be assessed and inspected according to the Stress Corrosion Cracking Direct Assessment (SCCDA) Methodology. The guidelines of international standard NACE SP0208-2008 "Stress Corrosion Cracking (SCC) Direct Assessment Methodology" shall be considered for the implementation of this methodology.

The development of the SCCDA process in pipelines covers the following sub-activities:

1. Pre-assessment: Collection of historical and current data required to prioritize/classify each pipeline into segments potentially susceptible to the SCC mechanism, helping select the specific locations to carry out excavations in these segments.

This stage shall include a detailed analysis and assessment of the information to be collected in accordance with the recommendations detailed in Table 1 of the standard NACE SP0204-2008:
- Data related to the pipeline
- Pipeline construction data
- Soil/environment characteristics
- Activities, records and history of corrosion control
- Operational data of the pipeline

Pipeline segmentation and prioritization/classification according to susceptibility to SCC

As a result of the analysis and compilation of the information mentioned above, each pipeline shall be prioritized and classified in segments, according to the susceptibility to SCC.

It is essential that the criterion, model and/or main variables to be considered for the segmentation of the pipeline be detailed according to its susceptibility to SCC.

Identification of the locations (or segments of pipe) where additional activities of indirect inspection and subsequent assessment in the field shall be performed.

Considering that indirect inspection in the system is required, the following activities shall be performed:

- Select and identify the locations (segments, sections) where additional indirect inspection activities are required.
- Select the techniques/indirect testing required.

2. Indirect assessment: In this activity the following activities are required:

- Field implementation of techniques/indirect inspection testing required
- Integration and analysis of the results obtained in the inspections performed
- Classification/final prioritization of the susceptibility of pipeline segments
- Final selection of the points where direct inspection (detailed examination) activities are to be performed.

3. Direct examination: The objective of this stage is to expose the surface of the pipeline at the points selected during the previous activity in order to take non-destructive measurements and collect relevant data to assess SCC.

The following activities shall be performed at this stage:

- Selection of optimal non-destructive methods to be implemented in the field. In all cases, methodologies accepted and recommended by international standards shall be selected.
- Development of a procedure of sensitive data/information to be collected during the process of detailed examination.
- On-site verification prior to excavation.
- Performance of interventions and non-destructive testing at each location selected for this purpose and at selected locations. Collection of data in the field.
- Analysis of results of the evaluations carried out in the field. Comprehensive SCC assessment in every location inspected.

In the event that cracks associated with SCC are identified, a detailed analysis of the type of cracking observed and the severity of the damage shall be performed

4. Post-evaluation: The following activities shall be performed at this stage:

- Assessment of the need for mitigation activities
- Prioritization of actions to be taken in the event of identifying the existence of SCC in the pipeline
- Definition of reassessment intervals
- Evaluation of SCCDA process effectiveness

9.2. Pipeline Fitness Management

This Chapter aims to provide the general criteria for the management of repairs of pipelines affected by anomalies detected in the inspections scheduled in the inspection plans arising from mechanical integrity management according to the guidelines of the corresponding ARPEL manual.

It is designed to manage repairs to facilitate follow-up by those responsible for maintenance management and improve the communication among those responsible for integrity management and maintenance managers.

Therefore, this Chapter is not intended to be a manual of repair techniques for specialists, but managers. Consequently, as regards technical aspects, reference will be made, whenever possible, to the standards of the industry or existing legislation of each country.

9.2.1. Criteria for Prioritization of Interventions

a) Criteria Based on Risk Analysis

Prioritization of repairs according to risk aims to perform the required interventions in the pipeline so as to mitigate the risk of the pipeline gradually to risk values acceptable for operation.

b) Criteria Based on the Mechanical Solicitation to which Pipeline is Subject.

For the prioritization of defects according to their mechanical solicitation, different methods are used to calculate the remaining strength of the various defects (ASME B31G, 085dL, DNV RP-F101 single defect, effective area, DNV RP-F101 complex shaped defect, API 579). Upon determining the resistance pressure value, a repair plan is established based on the defects under the highest mechanical solicitation.

c) Criteria of the Operator Based on the Experience of its Specialists

On numerous occasions, the experience of those responsible for pipeline integrity and maintenance is essential for the prioritization of defects, due to special conditions that could accelerate the growth of the defects reported by the ILI inspections.

d) Use of GIS Systems

For the prioritization of interventions, the use of a GIS system helps primarily in viewing the areas with problems of combination of threats, and thus prevent the uncontrolled growth of different types of threats.

e) Requirements of Codes According to the Time Allowed for the Repair of Defects and/or Anomalies

For the prioritization of interventions, codes according to the maximum time allowed for the repair are strict. Due dates are generally those established by the law for the compliance of an intervention. These criteria help and give the authority to the operating company to shorten the time limits or to develop new repair criteria.

If an intervention could not be performed in the terms established, this shall be notified to the pertinent government entity with jurisdiction on energy systems.

9.2.2. Actions for Fitness of Pipelines

As detailed in other chapters of this Manual, pipelines are subject to different threats: internal and external corrosion, manufacturing defects, forces of nature, third-party actions and incorrect operations.

Despite the preventive maintenance actions performed on the pipelines, certain events arise that prevent pipeline operation or increase the operational risk.

In order to restore the pipeline to safe operation, several fitness actions shall be taken, such as the following:

- Installation of reinforcements
- Replacement of segments
- Stabilization
- Cathodic protection works
- Changes in modes of operation

Tables 451.6.2.9-1 and 451.6.2.9-2 of ASME B31.4-2009 are used in liquid pipelines to define the scope of each repair.

9.2.2.1. Installation of Reinforcements

Reinforcements are specific repairs of the pipeline structure due to a localized anomaly. They are used when it is necessary to strengthen specific losses of thickness due to external corrosion, manufacturing defects, cracking, scratches caused by third-party actions and even intentional or unintentional punctures that may be repaired with no need to replace a segment of the pipeline.

In general, these repairs can be performed with the pipeline in operation by adapting the flow and pressure conditions. The maximum operating pressure is regained once the repairs have been completed.

The types of repair and reinstatement methods are:

- **Reinforcement Type A.** Sleeve welded longitudinally, used as mechanical reinforcement of the area containing the defect. The reinforcement shall be adjusted so that it can absorb the remaining loads that cannot be supported by the affected area. To ensure that the transmission of the load is effective, a hardenable filler, such as epoxy or polyester resin, shall be used to fill the void between the pipe and the repair sleeve.

  This is a non-intrusive repair. It cannot be used to repair leaks. It shall not be used if the remaining thickness is lower than 20 % of the nominal thickness. To install this reinforcement, the pressure shall be reduced by 20 %.

  The procedure for installation of this reinforcement shall consider:
  - Construction of the reinforcement
  - Preparation of the surface
  - Type and method for placing the filler
  - Installation method

- **Reinforcement Type B.** Sleeve welded longitudinally and circumferentially. It is capable of withstanding internal pressure. It is used as mechanical reinforcement of the area containing the defect.

  - It can be used to repair leaks.
  - Its load capacity shall be the same as that of the transportation pipeline being repaired.
  - Pipeline wall thickness shall be assessed in the area to be welded.
  - The ends of the sleeve shall not be near the heat-affected zone in the circumferential welds.
  - Qualified procedure and welders.
  - May transfer longitudinal tension.
  - The use of a low-hydrogen welding procedure is essential.

- The reinforcement shall be adjusted so that it can absorb the remaining loads that cannot be supported by the affected area. To ensure that the transmission of the load is effective, a hardenable filler, such as epoxy or polyester resin, shall be used to fill the void between the pipe and the repair sleeve.

- **Clamp.** Provisional mechanical reinforcement designed to support internal pressure.

- **Composite sleeve.** Sleeve that can be used as repair under certain conditions and for different types of failures. The codes contain the limitations to permanent repairs.

  - Composite material usually composed of fiber glass and a polymer matrix.
  - Easy to apply, for repairs that are difficult to access.
  - No welding required.
  - Qualified personnel required.
  - Not susceptible to the traditional methods of corrosion.
  - Applicable in complicated geometries, such as curves.
  - Can be installed in anomalies with metal loss lower than 80% of pipeline wall thickness.
  - To ensure that the transmission of the load is effective, a hardenable filler, such as epoxy or polyester resin, shall be used to fill the void between the pipe and the repair sleeve.
  - It shall be adjusted properly so that it fits perfectly on the entire surface of the pipe.
  - It shall be installed at least 2" far from the defects.
  - Check the adhesive bond and proceed to sealing.

- **Grinding.** Removal of the defect by grinding or mechanical treatment has a very limited application. Limitations are available in the corresponding codes.

9.2.2.2. Replacement of Segments

This consists in the replacement of one or more pipeline segments. This repair method is used for a very large area containing defects, when deformations affect the passage of the scraper or when there are segments with defects that the operating company considers necessary to replace.

A shutdown of operations or the use of plugging/bypassing techniques are required to isolate the area to replace and proceed to joining the new line to the existing one.

The tasks associated with a change of segment are the following:

- **Definition of convenience of pipeline segment replacement and selection of the optimal length to change.** Several items shall be considered to define the scope of a pipeline segment replacement, such as the conditions of adjacent pipelines, the conditions of coating in the area and other anomalies that, in the opinion of experts, could cause problems in the future.

- **Studies.** Regulations in force require that before replacing a pipeline segment it is necessary to carry out different studies in order to protect the environment and people safety.

- **Technical specifications.** Technical specifications shall be established in accordance with current regulations on construction and maintenance of transportation pipelines.

- **Management of permits.** In order to perform this work, it is of vital importance to obtain permits for interference, authorities and owners.

- **Hydrostatic test.** A hydrostatic test shall be performed to new segments in accordance with the regulations in force.

- **Acceptance tests.** The minimum acceptance tests required by pipeline construction codes shall be performed and documented.

- **Final report and compliance report.** A final report shall be issued in accordance with the specifications and under the format required by each company, to be submitted to the regulatory agency in each jurisdiction.

9.2.3. Adjustments to Operating Conditions

In some cases, the only way to lower the risk to an acceptable level is by modifying the operating conditions. Some of the actions that can be performed are:

- **Recalculation of MAOP.** According to the failure pressure calculated, and given the impossibility of repair, it is necessary to define a safe operating pressure with the safety factors referred to in the design.

- **Modification of protection parameters and control loops.** With the new pressure defined according to the monitoring system of each operating company, the new protection parameters shall be defined to ensure that the pressure at the specified point does not exceed the value defined.

- **Management of change.** Each operating company shall document, according to its procedures, all the changes made to any facility that can modify the operating pressure at any point, even when the MAOP is not exceeded.

Before an operational modification is carried out, a risk analysis of the operating facilities with the proposed modification should be performed.

10. Integrity Program Evaluation

Integrity management programs shall be evaluated on a periodic basis, together with indicators, by performing internal reviews that allow ensuring the effectiveness of the integrity management program and the achievement of its goals. This should be the practice of the company's senior management. It is also possible to use services provided by third parties to help during audits of the management program.

Evaluation must allow the pipeline operator to determine if the action plan resulting from the risk assessment exercise was applied, and if the application of the different activities included in such plan was really effective in the mitigation of threats affecting the pipeline integrity.

10.1. Performance Indicators

It is necessary to establish and measure the performance indicators to know if the action plan was applied and determine the effectiveness of such plan, in order to achieve the goal of any pipeline operator, which is basically to develop its operations in such a way that there are not adverse effects on employees, the environment, the public and its customers. Performance indicators are an important part of the pipeline integrity management program.

Even when each company should establish and qualify the most appropriate indicators for its management on the basis of the type and size of its operations and the overall context of its business, following is the description of some indicators that may be useful to measure the performance of the pipeline integrity program. ARPEL will define some indicators with which benchmarking among ARPEL member companies will be conducted.

- Performance indicator and a goal to reduce the total volume of unexpected leaks and/or ruptures with an ultimate goal of zero.
- Inspection plan monitoring indicator = inspections performed/scheduled.
- Performance indicator and a goal that documents the percentage of integrity management activities completed during the calendar year (completed work orders vs. planned work orders).
- Consideration of inspection recommendations = performed priority recommendations/issued recommendations.
- Performance indicator and a goal to track and evaluate the effectiveness of the community outreach activities (public education program).
- Periodic follow-up of the pipeline integrity management program, including a summary of performance improvements (e.g.: levels of cathodic protection, efficiency of the cathodic protection system, level of internal corrosion rates in mils per year – mpy, effectiveness of the chemical treatment, ILI results, among others).
- Performance indicator based on operational events that have the potential to adversely affect the pipeline integrity (for example, unplanned valve closure, ruptures due to overpressure, failure in the control system, failure in the relief and safety systems, others).
- Performance indicator to demonstrate that the integrity management program reduces risk over time with a focus on high-risk items (initial risk level vs. actual risk level).
- Performance indicator of history of failures before and after the integrity program.
- Performance indicator of response to incidents before and after the integrity program.
- Indicators to measure the kilometers of pipeline diagnosed by ILI before and after the integrity program.
- Indicators to measure the pipeline segments not diagnosed by ILI, pressure tested before and after the integrity program.
- Indicators based on Integrity audits.

10.2. Auditing

Audits are very important to evaluate the effectiveness of an integrity management program and identify areas of improvement. Audits may be performed by personnel with the organization (self- assessments) or by auditors from outside organizations. Examples of questions that integrity management auditing programs should address include:

- Has an integrity management plan been implemented in your company?
- Are activities being performed as outlined in the program documentation?
- Are responsibilities clearly assigned in the integrity program?
- Are there procedures and instructions for the performance of important activities in pipeline operations, maintenance and preservation?
- Are procedures and instructions available to those who need them?
- Are the people who do the work (operations and maintenance) trained to perform their duties satisfactorily?
- Are qualified and certified people employed when required by regulation?
- Is there an adequate organizational structure to implement the established integrity management system?
- Are all activities required within the integrity program documented?
- Is there a logical methodology to develop risk assessment exercises?
- Are there established criteria for repairing, replacing or rerating damaged pipelines?
- How often is the action plan reviewed and the risk reassessed?
- Are action plans developed in risk assessment exercises being duly applied?

10.3. Continuous Performance Improvement

Since the details of the operator integrity management program may vary, so too will the appropriate set of performance measures.

Non-conformities reported in internal and external audits and the results of performance indicator measurements should be used as additional information sources for understanding the effectiveness of pipeline integrity programs. These results shall be considered in future risk assessment workshops.

The results of performance indicator measurements and audits of the risk management program, including follow-up recommendations, shall be reported to those individuals who are responsible for pipeline integrity and operations. The performance of the integrity program shall be reviewed annually, addressing deviations from measurements and non-conformities found.

11. Standards, Regulations and Technical Documents

Following are some standards, regulations and/or technical documents used in the development of this subject, which may be applied voluntarily in pipeline integrity management.

Operators shall take into consideration national regulations and specific procedures of their companies.

- API STANDARD 1160 - Managing System Integrity for Hazardous Liquid Pipelines.
- SME B31.8S Managing System Integrity of Gas Pipeline
- API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition.
- API RP – 579-1 - Fitness for Service, Second Edition.
- API RP – 580 - Risk Based Inspection, First Edition.
- DOT 49 CFR Part 192. Subpart O. - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standard. Pipeline Integrity Management. Department of Transportation.
- DOT 49 CFR Part 195,452. Transportation of Hazardous Liquids by Pipeline. Pipeline Integrity Management. Department of Transportation.
- NACE (National Association Of Corrosion Engineers) RP-01-69 - Standard Recommended Practice Control of External Corrosion on Underground or Submerged Metallic Piping Systems.
- API RP1110 - Pressure Testing Liquids Pipelines.
- NACE Standard RP0502-02 Standard Recommended Practice Pipeline. External Corrosion Direct Assessment Methodology.
- ASME B 31.4 Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids.
- ASME B 31.8 Gas Transmission and Distribution Piping Systems.
- API Publication 1156 Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines.
- DOT CFR Part 195 Transportation of Hazardous Liquids by Pipelines, Guidelines for the Assessment of Dents on Welds.
- Pipeline Research Council International – Project PR -2189822 - Dec. 99 Rosenfeld M. J.
- API Recommended Practice 1162 Public Awareness Programs for Pipeline Operator.
- API 1130 Computational Pipeline Monitoring.
- API 1149 Pipeline Variable uncertainties and their effects on Leak Detectability.
- API 1155 Evaluation Methodology for Software Based Leak Detection.
- API RP1102 Steel pipelines crossing railroads and highways.
- API 1163 In-line inspection systems qualification standard.
- Specific corporate procedures of pipeline operators applicable to this Manual.
- Regulations and laws in force in the countries of ARPEL member companies.

APPENDIX A – Modes, Actions and Methods to Determine and Control Internal Corrosion

A.1. Determining the Threat

A.1.1 Development of a Master Plan Defining an Internal Corrosion Management Program

Internal Corrosion Management can be defined as the systematic assessment of the corrosion process, correlating the corrosion form and rate to the process parameters and the physical, chemical and microbiological properties of the fluid to avoid or control corrosion, keeping it at acceptable levels in order to preserve the structural integrity of the pipeline and to guarantee production, product quality and environmental quality.

For the implementation of the Internal Corrosion Management Program, it is necessary to generate a database containing all the information required for environmental corrosion treatment and analysis in order to determine and implement corrective and/or preventive actions. This interdisciplinary information may vary for different pipelines according to the specific characteristics of each system, the characteristics of the transported fluid, pressure, temperature, etc.

A previous study of the whole process is required to develop the database, in order to determine the main parameters to analyze and monitor during equipment operation. This requires an articulation with all the areas involved in the process, as the information and knowledge are not necessarily centralized in one single area or person.

It is necessary to develop basic guidelines to be complied with for the implementation of the Internal Corrosion Management Program. There shall also be a definition of the basic premises, the internal corrosion management strategy and the internal corrosion assessment techniques to adopt.

As a strategy for implementation of the Internal Corrosion Management Program, monitoring services provided by expert companies may be hired, if thus established by the operator as a program implementation technique. This requires an implementation schedule regarding all the necessary monitoring stages, those responsible for their execution, the implementing authorities, the monitoring term and the program audit.

There shall also be definition of the different aspects of the pipelines to be monitored: quantity, points or locations to be monitored at each pipeline, access facilities to such points, specification of equipment and accessories, and physical, chemical and microbiological characteristics to assess for internal corrosion monitoring.

A.1.2 Internal Corrosion Assessment Criteria

The corrosion potential of the transported fluid may be classified into three types:

- Type A – Severe/High
- Type B – Moderate
- Type C – Low

The corrosion potential types mentioned above are based on the analysis of the results obtained by any of the following items:

A. Corrosion rate
B. Evaluation of the result of the loss of thickness obtained by the instrumented pig
C. Pipeline historical failure information

D. Conditions of the process and physical and chemical characteristics of the transported fluid

The pipeline corrosion potential is classified as severe/high if at least one of the three first three criteria (**A, B or C**) so indicate it. If there is no evidence about the severity from the three first criteria, then the last criteria or item (**D**) shall be used for assessment.

In criteria **C**, if the transported fluid were already being treated by a chemical product, inhibitor, biocide and/or oxygen sequestrator, the potential shall be classified within the moderate or slight types based on the evaluation of the effectiveness of the injected chemical treatment or the corrosion rate.

A.1.2.1 Assessment Criteria according to Corrosion Rate

Fluid corrosion assessment is carried out measuring the corrosion rate with at least two different techniques:

- Mass loss coupon (gravimetric technique)
- Corrosion sensor by electric resistance probe (ER)

The determination of the corrosion potential with the gravimetric technique shall be confirmed by at least two successive measurements or by at least one measurement that agrees with the result of the ER technique. The assessment by mass loss coupon or by the probe or test piece of electrical resistance can be interpreted in a qualitative way with the classification of corrosivity of the fluid as shown in table A-1.

The ideal coupon exposure time shall be determined according to the results of the electric resistance probe (if any), and cannot be more than six months. If the first mass loss coupon assessment determines that corrosion is severe, the frequency of withdrawal of the following coupons shall be shorter (generally between 30 and 45 days).

Corrosion potential based on the classification of the corrosion rate	Uniform corrosion rate (coupon) (mm/year)	Corrosion rate Type of pitting (coupon) (mm/year)
Severe	> 0.25	> 0.38
High	0.13 – 0.25	0.21 – 0.38
Moderate	0.025 - 0.12	0.13 - 0.20
Low	< 0.025	< 0.13

Table A-1: Qualitative categorization of the corrosion potential in carbon steel oil production systems (NACE SP - 0775-2013)

A.1.2.2 Assessment Criteria according to Instrumented Pigging Report

According to the pig run report, the fluid may be classified as potentially severe and/or the pipeline as potentially critical when, after a validation of the defects through field measurements, the results reveal severe corrosion rates, i.e., higher than 0.25 mm/year, calculated based on one of the following criteria:

- The highest loss of thickness divided into the time of operation of the pipeline or segment (in the case of a replacement)
- The highest loss of thickness of the same defect between the two last inspections (if any)

If there are two instrumented pig runs, it is important to evaluate the technology used in each case. Preference shall be given to the use of pigs with similar technologies, for better comparison of the data obtained from both pig run reports, in order to establish a more reliable pipeline corrosion rate.

It is important to note that, as inspections with non-destructive testing are generally performed at long intervals, a severe corrosion that occurred along a short time may not be evidenced. Thus, if the average thickness loss detected through the instrumented pig is not severe, there is no actual guaranty that there is not severe corrosion, i.e., that the fluid inside the pipeline has not had a severe corrosion potential at different periods.

It is also important to remember that inspection tools many times determine other defects apart from internal corrosion. In this case, the professional in charge of assessing pipeline integrity <u>shall consider the interaction of the defects found in the same area</u>. It is important to be able to check the corrosion defects found in the field by B-C scan presentation mapping to confirm or confront the data resulting from the pig inspection, in order to make proper decisions as regards actual sections and to determine the most appropriate method to repair the pipeline.

A.1.2.3 Assessment Criteria according to Historical Failure Information

Another way to assess the severity of pipeline corrosion is according to the historical failure information. Table A-2 contains a classification of the corrosion potential according to the historical information about failures due to internal corrosion:

Severe/High	If there is historical information about failures due to corrosion during the last 5 years or for over 5 years, and the causes of corrosion have not been eliminated.
Moderate	If there is historical information about failures due to corrosion from the last 10 years to the last 5 years, and the causes of corrosion have been eliminated.
Low	If there is no historical information about failures due to corrosion, or if those failures occurred more than 10 years ago, and the causes of corrosion have been eliminated.

Table A-2: Corrosion potential

A.1.2.4 Assessment Criteria according to Process Conditions and Fluid Characteristics

Even if the corrosion potential has been determined as moderate or low according to the above-stated criteria, it is necessary to check this classification according to process conditions and to the physical and chemical characteristics of the transported fluid.

It is considered that the fluid has severe corrosion potential if it presents at least one of the conditions noted below, associated with one or more items of Table A-3:

- Pipeline with presence of free water
- Gas pipeline with presence of free water (gas with no dehumidification treatment)
- Product flow < carryover flow with free water present

Parameter	Severe/High Potential	Moderate Potential	Low Potential
pH	< 5.6	5.6 < pH < 6.9	pH > 7
Bacteria concentration and activity	SRB concentration > 10^5 NMP/g or NMP/cm^2, growth between 1 and 6 days and presence of iron sulfide in the residues	SRB <= 10^5, growth between 7 and 14 days	SRB < 10^5, growth over 14 days
Partial pressure of CO_2 from t< 60 °C	pCO_2 > 15 psia, independent from V or 4 psia < pCO_2 < 15 psia and V > 5m/s	4 psia < pCO_2 < 15 psia and V < 5m/s or pCO_2 < 4 psia and 5m/s < V < 10m/s	pCO_2 < 4 psia and V < 5m/s
Partial pressure of H_2S in gas	P_{H2S} > 0.75 psia	0.01 psia < P_{H2S} < 0.75 psia	P_{H2S} < 0.01 psia
Content of H_2S in crude	> 300mg of H_2S per 1Kg of crude	---	---
Corrosion of derivatives according to NACE TM-0172	C, D and E classification	Corrosion B^+ and B	A and B^{++}
Content of dissolved oxygen concentration in the water (oil pipeline)	Higher than 50 ppb	Lower than 50 ppb and higher than 20 ppb	Lower than 20 ppb

Table A-3: Corrosion potential

Due to the complexity of the corrosion processes, some severe and moderate corrosion cases might not be included in Table A-3. In such case, the expert in charge of managing internal corrosion may classify the pipeline corrosion potential according to some other method (similarity, experience, modeling, etc.)

A.2. Variables Required to Manage Internal Corrosion

Some data and analysis shall be monitored to classify the corrosion potential. The quality of the monitored data and the reliability of the results obtained are related to the information collection and arrangement procedures, the analysis methodology and the assessment methodology. It is also important to determine the frequency of the assessment of the data collected during monitoring.

The main variables and parameters monitored to manage internal corrosion are:

- Corrosion rate measured with corrosion testers (coupon and/or electric resistance probe)
- Chemical and microbiological evaluation of the fluid (to determine the presence of water)
- Chemical and microbiological evaluation of the corrosion residue
- Operating variables (type of flow, pressure and flow rate)

A.2.1 Data Collection Frequency

The frequency of collection and analysis of corrosion coupons, fluids and residues depends on the corrosion severity and the process variability. If there are no supplementary data, the following frequencies may be used:

Corrosion potential	Maximum frequency recommended
Severe/High	Quarterly (fluid and residue) and 45 days (coupon)
Moderate	Semiannual (fluid and residue) and quarterly (coupon)
Low	Semiannual (fluid, residue and coupon)

Table A-4: Data collection frequency

A.2.2 Analysis of Fluids and Residues

The chemical and microbiological analysis of fluids and residues is important to determine the corrosion agents and mechanism. Only with this information can the corrective or preventive measures be determined. The analysis shall be performed in duly qualified and certified laboratories using the same testing methodology at all times.

Another important aspect is the sample collection site (fluids and residues). Whenever possible, it is recommended to collect samples in the tank (before pumping), after the injection pump of the chemical product, if any, and at the end of product delivery.

A.2.3 Corrosion Probes – Mass Loss Coupon

This is one of the most useful techniques to monitor corrosion. Coupons have a specific shape, size and surface area and are usually made of a metal with a similar chemical composition to that of the process equipment.

Their weight and surface preparation are recorded before the flowing process begins, and after a specific period of exposure to the system, they are weighed and visually inspected again. The laboratory analysis provides the corrosion rate in mpy, as well as inspections (before and after cleaning) and measurements of visual damage (such as dents).

Coupons provide precise results at a reasonable cost. They are easy to use and may provide general quantitative and visual information about several corrosion types without depending on theoretical approximations. Coupons are also extremely versatile, as they may be used in any type of corrosion environment.

The determination of the ideal point or site for coupon installation is one of the most arguable items of internal corrosion monitoring. There is no set rule, but an important fact shall be considered: **Corrosion will only occur at points where there is accumulation of water, or a continuous and intermittent water film.** The expert shall determine this point based on his knowledge and experience with other pipelines, on literature data and on the use of specific software which determines whether liquid will be formed, as well as its volume and location.

Corrosion probes shall always be installed in the lower part of the pipeline and aligned perpendicular to the pipeline. In the case of dry gas pipelines, the probes shall be installed in the lower and in the upper parts.

If possible, the corrosion probe shall be a flush-mounted probe, where the analyzed coupon area is installed along the interior surface of the pipeline, simulating actual transportation conditions and not disrupting pigging.

The coupon preservation procedures, weight and assessment, as well as the coupon installation points, shall be specified in specific procedures within the adopted Master Plan.

A.2.4 Corrosion Probes – Electric Resistance Probe

The electric resistance probe is one of the corrosion monitoring techniques available in the market that provides on line corrosion data. The advantage over the other techniques is that it offers the possibility to measure the metal loss regardless of the electrolyte resistance, even if water is not in contact with the probe.

The sensor sensitivity is reversely proportional to its thickness. The selection of the sensor, as regards its operating life and response time, depends on the estimated corrosion rate. As the current rate and the potential process variants are known, this sensitivity may be modified.

The value of the corrosion rate is a qualitative value, i.e., the calculated rate is not always similar to the one obtained from a corrosion coupon for the same exposure period. However, the rate increase or decrease trend based on time is true, indicating the increase or decrease in the corrosion of the transported fluid. Thus, it may immediately act in the process, as long as there is instability in the corrosion rate, in order to avoid the extension of the corrosion damage.

The data obtained with the probe, depending on the monitoring equipment characteristics, may be transmitted remotely, by telephone, cell phone, radio or satellite, and therefore become available in a PC in real time.

A.2.5 Operational Variables

As regards operating parameters, the corrosion experts shall define which parameters shall always be available, with a priority on online availability. Some of these parameters are: product type, temperature, pressure, flow, product characteristics and flow rate.

As far as possible, the experts must know all the existing fluid treatment units, and as applicable, monitor some of the equipment involved in the process. An example of this is the automation of chemical product injection pumps (inhibitors, O_2 sequestrators, biocides, etc.)

A.3. Internal Corrosion Control – Methods and Actions

Regardless of the corrosion severity for each pipeline, the following actions and facilities are recommended during operation:

- **Pigs** – All the pipelines shall have facilities for pig launching and receiving, both for pigs for water cleaning and carryover and for inspection pigs, which require larger launchers and receivers. The cleaning pig run frequency shall be defined according to corrosion severity or other parameters. The water carryover pig run frequency shall be as low as possible, shall be determined according to the amount of water in the pipelines and shall be adjusted according to the results obtained from usage of those pigs. It is also important to consider the types of cleaning pigs, as the carryover efficiency also depends on the pig quality.

- **Tank drainage** – A structured program to drain water from the tank bottom shall be implemented. It is important to consider that a thorough analysis of the drained fluid shall be performed during the drainage stages.

- **Filtering** – A filtering system that minimizes as much as possible the passage of solids generated by cleaning or present in the transported fluid shall be implemented.

- **Chemical treatment injection – Corrosion inhibitor, biocide and/or oxygen sequestrator -** It is important to have an injection inlet available in case it is necessary to inject any chemical product to prevent internal corrosion. Preferably, the whole injection system shall be automated and controlled inside the operation control room. All chemical products shall first be tested and their effectiveness and compatibility with the transported fluid shall first be evaluated in the laboratory in order to define its efficiency and inhibition dose, then adjusting the concentration in the field. Such evaluation shall be performed using protocols to show that the product will not affect the properties of fuels, especially aviation fuels. The pipeline shall be cleaned before injection to remove all the residues and undesirable solids that may affect treatment efficiency.

- **Flow rate and type –** Determining the flow rate and type required for water carryover is also important to control corrosion. Moreover, it shall be considered that the pipeline slopes and undulations might facilitate the precipitation of the water transported together with the oil.

- **Pipeline wall thickness** – In some pipelines it is impossible to control the corrosion rate using corrosion probes. In such cases, it is necessary to use other nondestructive testing techniques, such as ultrasound and instrumented pigging. It is a common practice to perform mechanical integrity assessments of pipelines transporting hazardous liquids with ILI tools every five years, but alternative methods are being considered to increase the frequency of inspections, if the operator has established and applied a mitigation program that has proved to be efficient to control internal corrosion. In some cases, such frequency may be shorter than five years if the damage mechanism generates corrosion rates and morphologies that are not easily controllable with internal mechanical cleaning and chemical treatments, such as CO_2 and/or bacterial corrosion. Consequently, each pipeline operator should establish, according to its own failure probability assessment, the frequencies required for ILI of each pipeline or pipeline segment, or the application of alternative techniques or methods with similar reliability in order to determine the mechanical conditions of the pipeline.

APPENDIX B – Modes, Actions and Methods to Determine and Control External Corrosion

B.1. External Corrosion Control

The most common external corrosion control methods are: adequate material selection, application of protective coating and painting, electrical insulation of distribution, delivery and receiving plants, adequate pipeline support and cathodic protection. Each method has advantages and disadvantages, but all of them should be considered when planning an effective and consistent program to control external corrosion.

B.1.1. Corrosion Control in Aerial Pipelines

Atmospheric corrosion control in an aerial pipeline is achieved through the application of protective coating to insulate the metal substrate of the corrosion environment. Among the most effective coatings made of paints there is a three layer system: the first sacrifice layer of inorganic zinc, the second barrier layer of epoxy polyamide polyamine and the third finishing layer of polyurethane or polysiloxane to protect coating from degradation by UV rays. However, the coating selection will depend on the proper and specific assessment of the environment where the pipeline is or will be installed.

When the pipeline is supported by concrete supports, H frameworks or clamps for aerial crossings, it is necessary to make sure that the arrangement of these supports does not facilitate the accumulation of moisture between the supports and the pipeline, and that the coating applied at these points has sufficient mechanical resistance and adherence to assume the weight of the structure without suffering indentation or being detached. These items shall be subject to a thorough inspection to check the correct control of corrosion and/or take any necessary remediation actions.

B.1.2. Corrosion Control in Pipelines with Aerial-Buried Interface

In pipelines with some buried and some aerial sections due to crossroads, access roads, subfluvial river crossings and other reasons, be them cased or not, corrosion due to differential airing and moisture is common. In these cases, it is important to apply a kind of coating that properly supports the mechanical stress in the buried section and the action of rain and UV rays in the aerial section, and that remains stable for as long as possible without cracking and/or detaching. In these cases, it is common to use paint systems of high solids with polyurethane or polysiloxane finishing in white color, or kraft paper or tapes to protect the coating from the UV rays.

These locations require special attention to check that the coating is continuous and remains adhered, so that there is no accumulation of moisture under the coating, as moisture does not vapor itself easily and therefore promotes corrosion.

Non-cased crossings are preferred for construction of pipelines, but if it is necessary to use cased crossings, then it is important to make sure that the casing is not in contact with the pipeline, in order to avoid the galvanic pair and the shielding of the cathodic protection in the casing.

The separators between the casing and the pipe shall be made of materials that prevent metallic contact and current flow among them. The seals at the casing ends shall prevent the entrance of water into the pipe. To mitigate the effect of corrosion due to differential airing, dielectric oil is usually applied between the casing and the pipe.

B.1.3. Corrosion Control in Buried Pipelines

External corrosion in buried or submerged pipelines is controlled by a combination of protective coating and cathodic protection. For cathodic protection to reach the required level as regards current and coverage, it is necessary to provide adequate insulation of the pipeline-related structures, such as distribution plants, delivery connections, support of aerial segments and receiving plants.

Protective coating is a passive protection that acts as the first barrier against corrosion by isolating the pipeline steel from the electrolyte (soil or water). The most common coatings for buried pipelines are: coal tar enamel, asphalt enamel, fusion bonded epoxy (FBE), extruded polyethylene, three-layer polytehylene, three-layer polypropylene and cold-applied tapes.

The cathodic protection is used in combination with coating for active protection for corrosion control when there are pores or any damage in the coating and the steel pipeline is exposed to the corrosive electrolyte. The cathodic protection essentially converts the steel surface of the pipeline into the cathode of an electrochemical cell through the connection with more electronegative materials that act as sacrifice anodes or through external sources (URPC or thermogenerators, among others) that drive the circuit current in the electrolyte from the anode bed to the pipeline.

The cathodic protection may be installed, monitored and maintained according to the requirements of international or national standards, or to the corporate standards of the operating company. The data obtained from the cathodic protection systems should be integrated with the data obtained from in-line inspections and with other information related to external corrosion, in order to establish the susceptibility of a pipeline to corrosion and to establish the probability of failure.

<u>It is advisable to perform monthly readings of the operating conditions of each cathodic protection rectifier.</u> Among other measurements, it is necessary to register the voltage and AC current, the adjustment of coarse and fine settings of voltage, the voltage and DC current, the pipe/soil potential next to the CPR, the hourmeter reading and the anode bed resistance.

This type of monitoring is currently facilitated with the installation of remote monitoring units, which also facilitate inspections of instant On-Off post to post potentials and CIPS.

External coating systems should be assessed, inspected and maintained. Corrosion control is highly dependent on the integrity of the external coating system. The NACE provides vast information on this topic and other corrosion engineering topics.

Coating integrity shall be inspected applying surface technology, such as DCVG and PCM, which enable decision-making after implementing cathodic protection reinforcement or changing or reinstating the coating.

B.2. Determining External Corrosion

When evaluating the need to perform an initial inspection to detect external corrosion, the operator should consider the following: pipeline age; pipeline wall thickness; coating type; coating conditions according to direct or indirect inspections (PCM or DCVG) or to cathodic protection current requirements; conditions of cathodic protection as shown by test readings; pipeline-soil potential readings; current requirements; anodic consumption; pipeline operating temperature; soil type, stating any conditions that might act as a barrier to cathodic protection, such as rock barriers; soil resistivity; physical and chemical characteristics of the soil or water (pH, carbonates, sulfates and bacteria); and historical information about previous cracks or rupture caused by external corrosion.

In the case of aerial pipelines, pipeline inspections carried out by duly trained inspectors allow determining external corrosion problems and evaluating the need to remove the corrosion products, reinstate or replace the coating and define whether mechanical inspections of the pipeline are required. These inspections are very important in the aerial-buried interfaces and in the supports of the pipeline, where corrosion is usual due to accumulation of moisture and differential aeration.

For buried pipelines, there are several alternatives to determine damage caused by external corrosion that might affect pipeline integrity. Some of these alternatives are: pressure tests, ECDA methodology and in-line inspection tools.

APPENDIX C – Modes, Actions and Methods to Determine and Control Natural Forces

C.1. Control of Natural Forces

Based on the geotechnical survey of the right of way and its surroundings done before the design and construction stage and before the beginning of the operation stage, the corresponding geotechnical and hydraulic zoning shall be developed. This will constitute the basis for assessment and implementation of a program that includes:

- Periodical inspections along the pipeline and field inspections in sites or areas that were registered as susceptible to the occurrence of geodynamical and/or hydrodynamical processes, implementation of topographic or instrumented monitoring, specific research activities, such as sampling for in situ or lab tests, exploratory drilling to check and define the characteristics of the soils, or identification and delimitation of any (new) strip of right of ways that might present potential or active risks to the physical security of the system
- All the topographic, geological, hydrographic, seismic and hydro-meteorological information developed and assessed, which shall be incorporated into the geotechnical zoning to keep it updated
- The periodical acquisition, assessment and interpretation of satellite images of the pipeline or the segments with significant critical conditions that might affect the physical security of the pipeline

This research is recorded in a geotechnical and geological report containing the following information, among other data: soil type and characteristics, intersection and location of water currents, urban infrastructure, roads, etc., location and boundaries of stretches with potential risk from natural forces (geotechnical zoning). Besides, in pipeline segments under instability conditions and risk from natural forces that cannot be avoided due to topographic or hydrographic constraints, monitoring reports and/or reports on stabilization or strengthening works recommended during construction are included.

The implementation of these actions and the availability of the corresponding documents are essential to establish, plan and optimize systems and methodologies to determine, identify and limit corrosion, as well as the adequate prevention and mitigation actions and the objective assessment of the active or potential risk. This means that the information detailed below shall be available for the efficient management of the risk associated with this type of threats.

C.1.1. Topographic and Geotechnical Information and Construction Works Drawings

Topographic plans including sections or transversal and longitudinal profiles, geotechnical, geological and hydraulic data (geotechnical zoning) performed to select pipeline run and design and construction works drawings including location of valves, crossing of rivers, signage, crossing of roads, populated centers and landmarks along the pipeline with UTM or geographical coordinates constitute an important tool to define the logistics (equipment, time, etc.) and the costs required to plan predictive, preventive and corrective maintenance related to these threats.

If the geotechnical zoning performed for pipeline construction is incomplete, the approach shall be to proceed to its integration and consolidation, planning and prioritizing actions to complete it in the short or medium term. In any case, from the start of the operation, the system manager shall implement plans and actions to identify, localize and limit these types of threats, evaluate them and assess the risk to pipeline integrity, and duly implement the adequate mitigation or control actions.

C.1.2. Technical Inspections of the Right of Way

Periodic land inspects made on foot or by road or water vehicle, and complemented with aerial patrolling (by helicopter or plane) by duly trained technical staff allow identifying, locating, characterizing and limiting directly, objectively and timely any stretches whose characteristics and conditions might make them likely to generate or reactivate natural processes (threats). They further allow the assessment of their potential or active risk to pipeline integrity and the implementation of the adequate actions for its mitigation. These inspections also allow the collection of information in the stretches by monitoring and from the behavior of existing works, thus optimizing the costs of maintenance of the right of way.

The information obtained from the inspection of each site showing potential and/or active threats shall be analyzed, defining their characteristics and scope, and the risk that those sites represent for the stability of the right of way and/or the physical security of the pipeline. According to the complexity and magnitude of the problem, the operator shall design works and mitigation and control actions, or contract specialized companies to conduct additional investigations, which shall include the development of the most technically and economically viable alternative solution.

C.1.3. Special Pipeline Protections

In the crossings of the pipeline with watercourses (rivers, streams) and vehicle traffic areas, it is necessary to reinforce the mechanic resistance of the pipeline with a structural concrete ring and to increase the burial depth (coverage). This may be complemented in some cases with natural drainage control and regulation structures or periodic topobathymetric surveys to assess the development and determine process trends. This procedure is also valid in non-permanent watersheds.

In the case of sub-fluvial rivers, which may be subject to the frequent carryover of sediments from the river bed, and where the conventional corrective actions (regulation and management of local hydraulics) have not had satisfactory results, mitigated or eliminated the risk, the alternative to bury (position) the pipeline under the potential carryover depth of active currents through directed drilling techniques shall be evaluated.

C.1.4. Inertial Instrumented Scrapers

Inertial or geometrical instrumented scraper runs are used to determine, register and locate with UTM coordinates any anomalies in pipeline geometry, such as dents, ovalities, crushes, wrinkle bends, and pipeline sections or points subject to stress generated by the surrounding soil. This information allows identifying and implementing preventive actions to mitigate, control or timely overcome these risk conditions.

C.1.5. Preventive and/or Corrective Maintenance of the Right of Way

Having an annual preventive-corrective maintenance plan for the right of way, duly trained staff to manage it and the adequate material resources and equipment to execute such program allows the control and management of these threats and an efficient response to emergencies. Without limitation, such program shall include:

- Performance of a program of direct physical inspection (terrestrial and/or fluvial) and aerial patrolling of the right of way. Preferably, it may be done by stretch and its frequency shall be defined according to its topographic and geological characteristics, accessibility, type of product transported, level of activity in right of way and existence of populated areas.

- Collection of information in the sites through control monitoring, according to established frequency and systems (topographic, instrumental, etc.).

- Topobathymetric control in river crossings with riverside erosion and/or subsidence of the bottom of the river channel.

- Execution of specialized studies in strip of right of ways affected by geodynamical or hydrodynamical recurrent natural processes with medium or high risk for the physical safety of the pipeline, including basic engineering and detail engineering alternatives technically and economically viable.

- Control of performance and maintenance of mitigation and stabilization works constructed.

- Removal of vegetation in the strip of right of way according to the width established by environmental regulations, and reforestation of strips affected by superficial erosion with proper plant species resistant to these processes.

- Execution of strain-relieving works on buried pipeline segments subject to stress generated by the soil.

- Joint inspection program and integration of information obtained by the external corrosion control area regarding the pipeline segments buried in soils with dissimilar physicochemical composition, changing electric resistance, etc. This includes sampling for the corresponding soil tests and/or measurement of soil strength and resistivity.

- Run of instrumented scrapers, either inertial, geometrical or for determination of thickness loss (due to internal or external corrosion).

- Permanent contact with political authorities, state or private officers in charge of management of public works, such as roads, electric lines, irrigation channels, management of waterways, etc., and populated centers intersecting or adjacent to the right of way, for proper coordination of the execution of new infrastructure in the surroundings of the right-of-way and pipeline maintenance activities.

C.1.6. Management and/or Implementation of a Geographic Information System

It is advisable to integrate all the information generated and collected about the activities and actions implemented in the pipeline predictive, preventive and corrective maintenance programs in GIS in a continuous manner for efficient management. The GIS is a computing tool that, based on the use of all the stored data and within reliable limits, enables risk assessment and an evaluation of the consequences of potential or active natural threats, or of threats of any other type that the pipeline faces. The GIS also allows planning and assessing the corresponding options and alternative solutions.

Legal regulations on the transportation of hydrocarbons by pipelines in many countries establish the implementation of the GIS to manage integrity. The application of this tool is feasible and viable in new pipelines. However, it is costly to develop it and adapt it to management of pipelines in operation, so its viability shall be analyzed according to the cost-benefit ratio. In pipelines which have been in operation for many years, and on which there is not proper information available, the system is very costly, and not feasible or reliable to apply.

As an alternative to the implementation or availability of a GIS, all the information, diagnosis, preventive or corrective actions planned or implemented in each natural process (threat) shall be gathered, integrated and consolidated in a specific record that shall always be kept updated. This dynamic action enables the continuous and timely assessment (according to the results obtained) of the planning and prioritization of actions and activities for predictive, preventive and corrective maintenance, and therefore the adjustment and redesign of the scope and baseline objectives for efficient integrity management.

C.2. Methods to Determine Threats of Damage Due to Natural Forces

C.2.1. Geotechnical and/or Hydrodynamic Investigation

Once a natural threat has been identified during the technical inspection of a right of way, the geotechnical or hydraulic direct investigation is the most objective technical method to assess, limit and value the risk that might entail a natural process (threat) on the stability of the right of way, its environment and/or the physical security of the pipeline, and to determine the most adequate prevention, control or mitigation actions. This investigation may be carried out by qualified personnel of the pipeline operator or by specialized companies (according to the complexity of the problem).

Considering the complexity of failure mechanisms in natural processes (threats), each site shall be surveyed and evaluated with a focus on its particular characteristics. These factors are more difficult to interpret.

An inherent natural aspect to consider when assessing the risk related to this type of threat are the seismic or meteorological characteristics of the area where the pipeline is installed, as anomalous seisms and/or meteorological phenomena are the main cause of catastrophic natural processes. Soil liquefaction, massive landslides or rockslides, activation of local or regional geological faults, damming of watercourses, among others, may cause important defects in the pipelines and even break them. The limitation and classification of the pipeline according to the seismic sensitivity and meteorological data of the area where they are installed are crucial to propose measures or preventive actions to mitigate or reduce the potential damage.

C.2.2. Establishment of Procedures and Routines

The establishment of procedures and routines to map, classify, inspect, monitor, maintain and perform the geological, geotechnical and hydrological management along the strip of right of way and the surroundings of pipelines in the soil or in watercourses facilitate the classification of the natural processes (threats) and the objective assessment of the risk they entail to pipeline integrity.

C.2.3. Verification of Anomalies Registered with the Inertial Scraper

The excavation of the pipeline to verify any specific geometrical anomalies registered with the inertial scraper (dents, ovalities, and pipeline sections subject to stress due to the surrounding soil), and the consequent observation and direct evaluation of the soil characteristics and the pipeline interrelation with the local geomorphology allow evidencing or confirming if these anomalies have been caused by:

- Rock fragments that have not been removed during construction (deficient supervision)
- Competent/incompetent soils interlaying (different soil setting)
- Superficial or fluctuating freatic level seasonally altering the carrying capacity of the soil (solifluction)
- Predominance of muddy soils and/or fine sand (liquefaction)
- Soil creep
- Others

Once the causes have been determined, the remediation actions will be designed and implemented.

C.2.4. Identification of Sensitive Areas

By consolidating and continuously integrating geological, geotechnical, geomorphological and hydrological seismic information, and information on anthropic activities, those areas that are sensitive to the occurrence of natural processes shall be defined and delimited in the drawings of the pipeline route, classifying their hazard and their geodynamical and hydrological risk (high, moderate, low and no risk), and establishing and planning the corresponding preventive, control and mitigation actions.

The characterization of the risk of sensitive areas shall be periodically updated, or if any significant changes occur, the maintenance activities shall be duly adjusted, adapted and/or rescheduled.

APPENDIX D – Modes, Actions and Methods to Determine and Control Third-Party Damage

D.1. Control of Third-Party Damage

Third-party damage is one of the usual causes of pipeline leakage. Any integrity management program of a pipeline operator shall include mitigation activities to prevent third-party damage. The third-party damage mitigation activities may be identified during normal pipeline operation, during the initial risk assessment, during the implementation of the baseline plan or during subsequent tests. The results of in-line inspections are not mandatorily required to establish and carry out mitigation actions.

The following mitigation activities should be considered:

D.1.1. Line Marking

Line marking, such as marking posts every kilometer, is part of the first line of defense against involuntary third party-incidents. Additional markers make the pipeline more visible to third parties working in the vicinity. Line markers should generally be required on both sides of each road, highway, railroad, and water crossing. In areas of high third-party activity, intermediate line markers should be installed so that at least two markers are visible from any location along the line. Aerial line markers should also be utilized, where applicable, to provide markings for periodic aerial right-of-way inspections.

Pipeline markers should be colorful, highly visible and resistant to environmental conditions, state the pipeline right of way, bear an identification of the transported product, be labeled with the pipeline operator's 24-hour and seven-day emergency telephone number, bear an "Oil or Gas Pipeline Warning", show the universal sign for no excavation and provide the telephone number of the Information Call Center, if any.

D.1.2. Pipeline Maps

As a minimum requirement, the operators shall keep the maps containing the pipeline networks updated to facilitate the location of the pipelines in the field and to be able to timely provide information to the community, any third party or state agencies that require such information.

Developing integrated maps of the network of own and third-party pipelines is an excellent practice. They can also include other facilities of companies providing services, such as networks of aqueduct, networks or lines of communication or data transmission, sewage, railways and waterways, and land use plans. These maps will enable the integrated implementation of an Information Call Center and public education programs.

D.1.3. Information Call Center to Locate Facilities

The participation of pipeline operators and operators of other facilities or services, such as those mentioned above, organized through an Information Call Center, is very important to prevent damage to underground facilities. In order for this Information Call Center to be effective, the pipeline operator should make sure that all the pipelines within the system under its responsibility are included in jurisdictional documents and maps, and that the staff is duly equipped and trained to locate and identify properly the pipeline to reply to the requests for information made to the Information Call Center.

D.1.4. Optical or Ground Intrusion Electronic Detection

Another way to prevent third-party damage includes an optical fiber or metal cable, usually installed 30 to 60 cm above the pipeline, and monitored continuously. Should the cable become damaged or severed, the monitoring devices issue an alarm and identify the location of the cable damage. These devices are integrated into the pipeline programmable logic controllers (PLCs) and the SCADA system.

Optical or electronic ground intrusion detection systems may reduce the consequences of third-party intrusion in three ways:

- **Damage prevention.** The system may reduce the frequency of third-party incidents by alerting the operator of potential third-party intrusions before the pipeline is damaged.
- **Prevention of unintended releases.** A system alarm may reduce the likelihood of a leak due to retarded failure in the event the pipeline is damaged. This allows the operator to respond and perform an immediate inspection and/or repair at the location the event.
- **Spill minimization.** In the event that third-party intrusion results in an immediate rupture, the intrusion alarm, coupled with a release alarm, will allow a quicker response, and reduce significantly the volume that may be potentially spilled.

D.1.5. Increased Depth of Cover

Increasing the depth of the pipeline cover (for ex., 1.5 to 2.0 meters below ground surface) may place the pipe below many normal agricultural, excavation and river transportation activities, thereby reducing the chance of third-party intrusions. In pipeline sections where fuel is recurrently stolen, increasing the burial depth may discourage or hamper voluntary third-party actions, even more so if combined with additional mechanical protection, such as ballasting the pipeline or installing additional physical barriers.

Increasing the depth of the pipeline cover is also an important consideration at stream and other crossings that may be subject to scour or carryover of sediments. In these cases, the pipeline should be buried well beneath the potential scour depth of active streams, applying directed drilling techniques. When increased burial depth or cover is desired but not practical, mitigation options include concrete caps, hexapod blocks, increased line marking, electronic warning tapes as well as plastic tape and mesh marking above the line, or fencing off areas particularly susceptible to third-party damage.

D.1.6. Public Education

Pipeline operators currently implement educational and public awareness programs. These programs educate the public, emergency responders and persons engaged in excavation-related activities as to the potential locations and dangers, and appropriate emergency responses associated with the pipeline facilities. These programs can help reduce a pipeline operator's exposure to third-party actions and enhance emergency response in the event of an incident. It is advisable to establish a public education and awareness program in those places where there is a high level of activity on the right of way and the consequences of leakage would be greater. These programs should extend to service providers, construction companies, road construction companies and mining companies performing activities on the right of way.

D.1.7. Right-of-Way Maintenance and Control

Having a plan to maintain rights of way and install additional protection for aerial pipelines will reduce the possibility of third-party damage and enhance the ability for response to an emergency. The following actions are highly beneficial to prevent third-party action:

- Clearing of vegetation in the right of way, whose frequency will depend on the growth of the vegetation on each pipeline segment. This will enable better visualization of the pipeline, both for third parties and for the patrolling and maintenance staff.

- Removal of trash, weeds and other objects near the pipeline, thus preventing the aerial pipeline from the possibility of being affected by forest fires, intentional or unintentional.

- Establishment, together with the competent authorities, of a land use plan identifying the right of way and/or easement negotiated and agreed on construction of the pipeline.

- Control of constructions above or below ground near the pipeline, such as buildings, houses, schools, access roads, engineered structures, pavement, pools, fish tanks, earth dams or other.

- Control of the operation of heavy equipment over the pipeline, during maintenance of other engineered structures or facilities of the operator or of third parties.

- Control of blasting, excavation or drilling near the pipeline, due to road improvement, civil works or mining works.

- Delimitation or enclosure of some strips of the right of way may be necessary in some cases to prevent trespassing by the surrounding community.

- Control of excavation or construction works near the pipeline, which may cause an increased coverage over pipeline, generating additional external load beyond pipeline design specifications.

- Establishment of right of way or easement and surveillance to control the respect for and preservation of such strip.

D.1.8. Frequent Right-of-Way Inspections

These regular inspections enable the pipeline operator to identify activities that may encroach upon its right of way before the pipeline facility can be impacted. Each operator shall establish the appropriate frequency for this patrolling or the frequency established by the regulations of each country, depending on the assessment of the surrounding conditions and the route of the pipeline. Such patrolling may be carried out on foot, by car, by boat and/or by aircraft.

It is advisable that pipeline operators be in frequent contact with land-use planners and other government agencies to minimize encroachments of right of ways, and to jointly establish safety pipeline corridors that are respected by the community.

D.1.9. Mechanical Pipeline Protection

Mechanical protection is designed to shield a pipeline from third-party damage. This is usually considered from the construction of the pipeline, but it can also be installed in pipelines in operation in case of sites of high vulnerability to third-party actions, either voluntary or involuntary.

There are several modes of mechanical protection. For example, a segment of pipeline can be coated with reinforced concrete, installed over the top of the external corrosion coating. The external concrete coating can be installed at most coating plants or in the field with formwork, and is intended to provide mechanical protection from excavation equipment, or from gouges and punctures from other external forces, and even from the stealing of fuel through illegal perforation, complemented in some cases with additional mechanic protection barriers made of steel films or meshes.

Alternately, a concrete cap can be installed above the pipeline, C-shaped and at a depth of 30 to 60 cm, to provide a physical barrier to excavation above and along the sides of the pipeline. It is important that the concrete cap not contact the pipeline, in order to avoid the deterioration of the external corrosion coating and cathodic protection shielding.

A thorough assessment of high-risk areas to which this additional mechanical protection is worth applying is required for the selection and application of these methodologies, as access for further repairs is difficult.

In superficial pipelines running parallel to and next to, or crossing roads or railroads, where it is not economical and/or practical to bury the pipeline, steel or concrete barriers may be installed to prevent or mitigate the impact of vehicles or heavy machinery used for the maintenance of such roads.

D.1.10. Additional Pipe Wall Thickness

Additional pipe wall thickness may increase the resistance of a pipeline to third-party damage and natural forces. This option is normally only a consideration during the initial construction of a pipeline. The additional pipe wall thickness may provide mechanical protection against a puncture and allow the pipe to be gouged, with less chance of immediate leakage. The lower stress of the ring that results with a thicker wall also makes the pipe less prone to rupture.

At crossings of roads, water bodies or populated areas, where there is a high level of activity on the right of way, heavier wall pipe may be considered during construction.

D.1.11. Pipeline Marker Tape or Warning Mesh Installed over Pipeline

In the event that it is not possible to bury the pipeline deeper, marker tape or warning mesh installed above a pipeline is, in general, an additional measure to protect against third-party damage. This option is generally implemented during installation of the pipeline. The brightly colored tape or plastic mesh should typically be installed approximately 30-60 cm above the pipeline and, if possible, appropriately labeled with warning signs that the pipeline transports hazardous liquid, including operator name and telephone number.

D.1.12. Shared Right-of-Way Protocol

A written protocol shall be implemented in writing according to the right of way shared with other pipeline operators, facilities operators and/or service providers. This shall allow defining the procedures for excavation and maintenance of the pipeline and the right of way in general, including the cathodic protection systems, and it shall establish the level of responsibility with respect to the actions that each operator performs in its pipeline or facilities. As a fundamental rule, each operator shall previously notify the others of the execution of works that might affect the pipelines of third parties, so that they may take any required action to control any activity that might affect the immediate or future integrity of their pipelines.

D.2. Methods to Determine Third-party Damage

D.2.1. Visual Inspection

In the case of aerial pipelines, visual inspection is one of the most effective methods to prevent, determine and assess third-party damage. The initial report may be done by the staff that inspects the rights of way, who is duly trained to identify any risks related to third-party damage, and the damage mechanisms produced by this threat. Then, an expert in defect assessment may perform an analysis of each anomaly and establish the corresponding reinstatement actions.

D.2.2. In-line Inspection Tools to Detect Metal Loss

As mentioned in Appendix B, Chapter B.2.3, there are in-line inspection (ILI) tools to detect metal loss, which allow finding perforations, scratches or gouges in the pipeline wall. From the resulting reports, those requiring direct monitoring are selected, and only then is the decision on reinstatement made.

D.2.3. Geometry Tools

Geometry tools are typically used to find deviations in geometry (deformation), mechanical damage, dents and wrinkle bends. They are used to determine if passage of in-line inspection tools such as MFL and ultrasonic tools is possible.

Caliper tools measure deviations in the geometry of a pipeline's diameter. These tools use a set of mechanical fingers (arms) that ride along the internal surface of the pipe, or electromagnetic methods to sense the circumference of the pipe. Any change in the geometry of the diameter of the pipe will cause a relative movement of the arms or a change in the electromagnetic reading and will be recorded. Changes in the pipe diameter geometry can be due to pipe bends, dents, buckles, gate or check valves, or changes in wall thickness.

Caliper tools can determine if a dent is a smooth dent with no stress concentrator, which is generally not a concern, or a sharp dent which may be a concern, particularly if there is an associated gouge that could eventually fail due to fatigue. Even if it is a smooth dent, it is necessary to establish its percentage of restriction, its clock position, whether it affects the circumferential or longitudinal seam of the pipeline, or if it prevents the passage of the tools of interior cleaning and inspection (pigs).

When establishing the need for an initial inspection for dents and wrinkle bends, it is important to take the following aspects into consideration: the level of operator and third-party activities on the right of way, pipeline susceptibility to third-party damage, line age, filling conditions, diameter-wall thickness ratio, pipe wall thickness, interval and number of service pressure cycles applied to the pipeline and historical information on cracks or ruptures caused by dents or wrinkle bends.

The re-inspection intervals for geometry tools depend on an assessment of the probability of additional activity in the area that might cause mechanical damage by third parties, known seismic events and soil stability problems. Re-inspection using deformation in-line inspection tools shall be based on the results of risk assessment.

D.2.4. Leak Detection System (LDS)

In its introduction, this Chapter mentions some technologies and methods that can be applied to establish and locate the presence of leaks in pipelines: acoustic emission, fiber optics, soil monitoring, ultrasonic flow meters, vapor monitoring, mass balance, real-time transient modeling, and pressure point analysis. Consequently, although leaks cannot be prevented, actions may be taken to mitigate their consequences, activating the Emergency Shutdown Devices and the contingency and mutual aid plans.

APPENDIX E – Modes, Actions and Methods to Determine and Control Operational Errors

E.1. Control of Operational Errors

The malfunctioning of equipment and/or instruments in pipeline systems may cause “transient conditions” that quickly reach the operational limits. For this reason, pumping stations and terminals have safety devices and alarms at practically all operational stages. These stages are controlled by computing systems that allow the elimination or reduction of any "transient condition" before it can cause damage to the facilities or the environment.

However, the plant operator and the Distribution Center supervisor are responsible for ensuring that the safety conditions of the pipeline system remain unchanged even if the equipment fails. Therefore, it is very important to receive proper training in order to maintain the safety of system operations until a solution is found.

The methods to minimize operational errors are basically the same as those used for operations management of any industrial facility.

The most frequent methods are:

E.1.1. Distribution Center

The operator ensures the coordination between the receiving, injection and pumping plants through a centralized organization called Distribution Center, which is responsible for compliance with the programs whose main objective is to set the execution times for operational maneuvers.

According to the technology available in the pipeline system, the operation might be within a range of operation from completely telesupervised operation to permanently staff-assisted operation in each facility.

E.1.2. Qualification of Operators

The operator shall have a system in place to ensure the adequate training of all the operational staff, guaranteeing that all the persons know all the descriptive procedures of the operations under their responsibility.

E.1.3. Global Protection Strategy

When there are unexpected situations, such as pipeline blocking or shutdown of a pump station, the time available to react might not be enough for the operator of the plant or the Distribution Center. Thus, it is necessary to develop a sequence of predefined actions that triggers automatically at each pump station if any of the above-mentioned events is detected, in order to minimize hydraulic transient conditions and therefore, rupture and/or fatigue risks.

E.1.4. Mechanical Protection (PSV)

Mechanical protections, such as PSV and rupture discs, are safety systems that act later than the global protection strategy.

E.1.5. Logical Protection
Pump stations and the pipe shall have such automatic protection that an equipment shutdown order, plant bypass opening order and/or relief plant bypass opening order is triggered if the authorized pressure set is exceeded.

E.1.6. Set Point Tracking
If there is an unexpected blocking downstream a pump station, the discharge pressure and the suction pressure will increase. As the station control shall keep the aspiration suction pressure constant, it will react to this event by increasing the velocity of suction reducing pumps, which in its turn will contribute to an increase in the discharge pressure. Until a maximum discharge set point is reached, the control of the pump station refeeds blocking positively.

In order to avoid positive refeeding, it is necessary to ensure that the pressure discharge set point is not very different from the actual discharge pressure, without being necessary for the operator to perform manual resetting frequently.

E.1.7. Emergency Shutdown System (ESD)
This is another mechanism to shut down the station and set it up safely. All this is done automatically from the operation room or from the field.

E.1.8. Leak Detection System
The leak detection system consists in monitoring pipelines from a computer through mathematical algorithms that improve the ability of a Distribution Center supervisor to recognize abnormal conditions that might indicate a potential product leakage.

E.1.9. Management System for Out-of-Service Protection and Critical Elements
Senior management shall establish general mechanisms to develop procedures to manage, register and control systems and safety protection elements that are out of service.

E.1.10. Operating Contingency Drills
Emergency drills should be conducted regularly to guarantee that the operational staff in the facilities has the knowledge and training required for emergency situations due to service and critical equipment failures.

E.1.11. Operation Manuals
Manuals, procedures and instructions on each critical operation shall be developed and made available.

E.1.12. Audits and Management Inspections
Periodic and systematic audits and management inspections to distribution plants, intermediate plants and receiving plants enable to detect any situation that might be a risk to pipeline integrity.

E.1.13. Identification and Signaling of Multiples
The updated and clear identification and signposting of pump station multiples helps the operators not to make operational errors that might adversely affect pipeline integrity.

E.1.14. Multiples P&IDs
The P&IDs of all the plants within the pipeline system shall be always updated and available at the operation room.

E.1.15. Management and Control of Change

Any changes that are not duly managed and controlled are an important cause of operational errors, and therefore, of the loss of pipeline integrity. It is important to have and systematically apply procedures, instructions and forms. This is necessary to manage and control the changes to make to the infrastructure and the operational conditions of the pipelines.

E.2. Methods to Determine Operational Errors

The pipeline operator shall ensure that the identification of operational errors through a system to analyze unplanned events and to disseminate the lessons learned. Operational errors may also be determined through methodologies to assess operational risks, such as HAZOP or any other.

APPENDIX F – Modes, Actions and Methods to Determine and Control Fatigue

Upon consideration of the three factors that may potentially cause fatigue and the categorization of threats that establishes whether fatigue sensitivity analyses are required, operating companies shall take two types of fatigue-management actions: establishment of baseline and fatigue risk analysis.

F.1. Establishment of Baseline

As the presence of cracks is a sign of pipeline fatigue, direct or indirect inspection is the method suggested to detect cracks in transportation pipelines.

The establishment of a baseline will provide the initial integrity condition to compare with the results of subsequent inspections. The baseline shall be established upon smart inspection using ultrasonic technique, EMAT or other method to identify and measure pipeline cracks. This type of inspections shall be performed periodically at intervals defined by each operating company, according to variations of variable loads in transportation pipelines, and to the fatigue analyses performed by each operating company that identify optimal reinspection intervals.

The comparison of the dimensions of cracks between inspections will allow the operating company to establish crack growth rates (as long as the inspection method allows sufficient sensitivity). It is suggested, however, that this be determined using a fracture mechanics analysis, as the crack growth rates may be too high to perform a new inspection before failure.

F.2. Fatigue Risk Analysis

Once pipeline cracks have been identified, it is necessary to perform an analysis to prioritize the anomalies, considering as a minimum the following scenarios:

- Trend of the anomaly to ductile or fragile failure in current condition (dimension of the anomaly and operating condition)
- Trend of the anomaly to ductile or fragile failure if anomaly grows over time (change in anomaly dimension)
- Trend of the anomaly to ductile or fragile failure in case of operating changes in the system (changes in pressure, temperature and flow conditions).

These analyses will provide a view of pipeline integrity when a crack is detected at inspection, in case of an increase in the size of the anomaly (if it is a time-dependent threat), and in case the anomaly is fit for continued service and there are plans to increase the operating limits of the system.

For each scenario, the analysis shall consider the entire fluctuating load required to ensure pipeline integrity and, as a minimum, its pressure and temperature. This shall be performed on the basis of pipeline temperature and pressure records at each point of interest. If records correspond to pipeline discharge and suction, they shall be interpolated with sufficient degree of reliability for subsequent analyses.

The properties of the materials shall be established on the basis of laboratory results, reducing the uncertainty of their use in pipeline integrity analyses. The theoretical values suggested in some standards shall be adopted with the safety factors that adjust the results to the same degree of reliability as values obtained in the laboratory.

Finally, the staff responsible for carrying out the analysis shall have the skills and experience necessary to ensure all aspects required to correctly determine pipeline integrity before fatigue. Each operating company shall establish the requirements of its staff and determine regular reviews that allow it to adjust the uncertainties in the analyses.

The result of the fatigue susceptibility analyses shall convey four clear concepts that indicate pipeline integrity before fatigue:

- Fatigue risk level (by individual anomaly or by section of the pipeline to be analyzed)
- Fitness of cracks or anomalies susceptible to fatigue for continued service
- Pressure value for of crack or anomaly susceptible to fatigue for continued service (safety pressure)
- Estimated time of intervention, inspection or reassessment of cracks or anomalies susceptible to fatigue

These four concepts will help establish the action plan for pipeline integrity.

APPENDIX G – Alternative Actions for Control and Mitigation of Threats – Acceptable Repair and Prevention Methods

Prevention, detection and repair methods	Time-dependent			Stable										Time-independent							
	Corrosion	Corrosion	Corrosion	Manufacturing		Construction				Team				Third-party damage			Incorrect operation	Climate and external forces			
	Ext.	Int.	SCC	W.S.	Pipe	Circ. welds	Const. welds	B&W	JF	Pack.	Valves	Seals	Tape	Imm failure	PTPD	Vand.	E.O.	Frosts	Lightning	Flood	Earthq.
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Detection and Prevention																					
Aerial inspection									X					X	X	X		X	X	X	X
Patrolling on foot	X								X					X	X	X		X	X	X	X
Visual/mechanical inspection						X				X	X	X	X					X			
01-800 Calls														X	X	X					
Reliability audits																	X				
Design specs.	X	X	X			X		X	X	X	X	X	X								X
Material specs.				X	X		X			X	X	X	X								
Manufacturing inspection				X	X		X				X	X			X						
Transportation inspection				X	X										X						
Construction inspection			X		X	X	X	X	X	X	X	X	X		X						
Hydrostatic test				X	X	X	X	X	X						X						
Public education														X							
Op. & Maint. procedures	X	X	X					X	X	X	X	X	X		X	X	X	X		X	X
Operator training																	X				
Marker interval (signposting)														X	X						
Deformation monitoring (landslides)																				X	X
External protection (perimetral fence, concertina wire)														X	X	X					X
Right-of-way maintenance														X	X						X
Wall thickness increase	X	X												X	X	X					X
Warning tapes or posts														X	X						
Corrosion control monitoring	X		X																		
Internal cleaning		X																			
Leak control measures	X	X							X	X	X	X	X		X	X					
Instrumented inspection equipment	X	X	X										X					X		X	X
External stress reduction			X					X	X												X
Heat tracer installation																		X			
Line relocation														X		X		X		X	X
Reinstatement	X	X	X					X	X						X						X
Coating repair	X		X																		
Depth increase								X						X		X					
Operating temperature reduction			X							X		X									
Moisture reduction		X																			
Inhibitor injector (control, coupons)		X																			
Thermal protection																		X			
Repairs																					
Pressure reduction	X	X	X	X	X	X	X		X						X						
Replacement	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X		X	X	X	X
Coating	X	X				X															
Routine repair			X	X	X	X	X								X	X					
Weld fillings	X															X					
Type B pressurized sleeve	X	X	X	X	X		X		X						X	X					
Type A reinforcement sleeve	X		X	X	X										X	X					
Compound sleeve	X																				
Epoxy-filled sleeve	X			X	X	X	X	X	X						X	X					
Mechanical clamp	X																				

Source: PEMEX – September 2007

Table G-1: Acceptable repair methods and prevention and mitigation measures against threats

	Data integration required to identify threats	**Time-dependent**				**Stable or resident**			**Time-independent**		
		1 Internal corrosion	2 External corrosion	3 Stress corrosion cracking (SCC)	10 Cyclic fatigue	4 Manufacturing defects	5 Weld/Manu facturing	6 Equipment	7 Third-party damage	8 Incorrect operations	9 Climate and external forces
1	Installation year	•	•			•					•
2	Type of coating		•	•							
3	Condition of coating		•								
4	Years with adequate CP		•								
5	Years with questionable CP		•								
6	Years without cathodic protection		•								
7	Soil characteristics		•								
8	Pipe inspection reports (bell hole)	•	•			•	•				
9	Detected microbiological corrosion (Yes, No, Unknown)		•								
10	Leak history	•	•								
11	Wall thickness	•	•								•
12	Diameter	•	•								•
13	Operating strength level (% SMYS)	•	•	•							
14	Information of previous hydrostatic tests	•	•	•		•	•				
15	Bacteria culture test results	•									
16	Gas, liquid or solid analysis, especially hydrogen sulfur, carbon dioxide, oxygen, water and chlorides	•									
17	Corrosion protection devices (probes, coupons, etc.)	•									
18	Operating parameters, particularly flow pressure and rate, and especially the periods when there is no flow	•									
19	Pipe age			•							
20	Operating temperature			•							
21	Distance of segment with respect to compression station			•							
22	Pipeline material					•	•				•
23	Manufacturing process (age of manufacture as alternative)					•					
24	Type of seam					•					
25	Joint factor					•					
26	Operating pressure history					•					
27	Identification of bent pipes w/wrinkle						•				
28	Joint identification						•				
29	Joint reinforcement after construction						•				
30	Welding procedures						•				
31	Circumferential welding reinforcement after construction						•				
32	NDT weld data						•				
33	Potential external forces				•		•				•
34	Soil properties and filling material depth for bent pipes w/wrinkle						•				
35	Maximum temperature ranges for bent pipes w/wrinkle						•				
36	Curvature radius and bend angle in bent pipes w/wrinkle						•				
37	Operating pressure history, incl. expected pressure and significant cycles, and fatigue mechanisms				•		•				
38	Year of installation of equipment that failed							•			
39	Data on regulating valve failures							•			
40	Data on relief valve failures							•			
41	Data on flanged seal failures							•			
42	Deviation from calibration point (outside manufacturer's tolerance)							•			
43	Deviation from relief calibration point							•			
44	Data on O-ring failures							•			
45	Data on seals / packing							•			
46	Vandalism incidents								•		
47	Pipe inspection reports (bell hole) where pipe was hit								•		
48	Reports on leakage resulting from immediate damage								•		
49	Incidents involving previous damage								•		
50	Results of in-line inspection for dents and grooves in the upper half of pipe								•		
51	"Single Call" records								•		
52	Right-of-way encroachment records								•		
53	Data on procedure review									•	
54	Data on audits									•	
55	Erroneous operation failures									•	

Data integration required to identify threats		Time-dependent				Stable or resident			Time-independent		
		1 Internal corrosion	2 External corrosion	3 Stress corrosion cracking (SCC)	10 Cyclic fatigue	4 Manufacturing defects	5 Weld/Manu facturing	6 Equipment	7 Third-party damage	8 Incorrect operations	9 Climate and external forces
56	Joint method (mechanical coupling, autogenous welding, arc welding)										•
57	Topography and types of soil (slopes, water crossings, water proximity, soil liquefaction)										•
58	Seismic fault lines										•
59	Soil acceleration profile near fault lines (acceleration >0.2 g)										•
60	Frost line depth										•
61	Calculation of internal strength added to external load The total strength shall not exceed 100% of the minimum yield strength specified.										•
62	Load conditions				•						
63	Soil movements				•						
64	Condition of suspension bridges				•						

Source: PEMEX – September 2007

Table G-2: Minimum information required for the calculation of probability of failure due to potential threats to pipeline integrity

ABBREVIATIONS		
1	Ext.	External corrosion
2	Int.	Internal corrosion
3	SCC	Stress corrosion cracking
4	W.S.	Defects in pipe welded seam
5	Pipe	Defects in pipe
6	Circ. Welds	Defects in circumferential welds
7	Const. welds	Defects in construction welds
8	B&W	Bends and wrinkles in the interior of pipe
9	JF	Joint failures
10	Pack.	Packing failures
11	Valves	Relief/control equipment failures
12	Seals	Seal failures
13	Tape	Damage to accessories
14	Imm. failure	Immediate failure due to third-party damage
15	PTPD	Previous third-party damage
16	Vand.	Vandalism
17	E.O.	Failure due to erroneous operations
18	Frosts	Frosts
19	Lightning	Reached by lightning
20	Flood	Floods and heavy rainfalls
21	Earthq.	Sudden earth movements

Source: PEMEX – September 2007

Table G-3: Acronyms

Regional Association of Oil, Gas and Biofuels Sector Companies in Latin America and the Caribbean

ARPEL is a non-profit association gathering companies and institutions of the oil, gas and biofuels sector in Latin America and the Caribbean. It was founded in 1965 as a vehicle for cooperation and mutual assistance between companies in the sector, with the primary purpose of actively promoting industry integration and competitive growth and the sustainable energy development in the region. Its membership represents over 90% of the upstream and downstream activities in the region, and includes national, international and independent oil companies, providers of technology, goods and services to the industry value chain, and other national and international institutions in the industry.

Mission

To promote the integration, growth, operational excellence and effective socio-environmental performance of the industry in the region, facilitating the dialogue, cooperation, development of synergies among players as well as the shared creation of value among members through the exchange and expansion of collective knowledge.

Vision

To be an institution of reference in the consolidation of the oil and gas industry, furthering the provision of reliable and safe energy that meets the growing regional energy demand in a sustainable manner.

MEMBER COMPANIES

MEMBER INSTITUTIONS

ALLIANCES

REGIONAL ASSOCIATION OF
OIL, GAS AND BIOFUELS SECTOR COMPANIES
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