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Task III.B.3 Final Report

DTPH56-14-H-00004 Improving Models to Consider Complex Loadings, Operational Considerations, and Interactive Threats

Eduardo Munoz and Michael J. Rosenfeld, P.E.

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DTPH56-14-H-00004 IMPROVING MODELS TO CONSIDER COMPLEX LOADINGS, OPERATIONAL CONSIDERATIONS, AND INTERACTIVE THREATS

TASK III.B.3 Final Report

to

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

December 30, 2016

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Task III.B.3 – Final Report

Eduardo Munoz and Michael J. Rosenfeld, P.E.

INTRODUCTION

The project described in this report was intended to enhance the understanding of interacting threats to pipeline integrity and to reduce the risk of incidents from such interactions. Important threat interactions were identified, and guidance is provided to assist pipeline operators with addressing these interacting threats in their integrity management plans.

BACKGROUND

The pipeline industry has been generally successful recognizing and mitigating the enhanced risk associated with some integrity threat interactions. However, some pipeline failures suggest that more complex interactions must be recognized, including defect responses to variable loadings, increased loadings, complex loadings, or changing environments. Interactions of resident conditions with changing operations or environments may increase the probability of failure, reduce the failure stress, change the mode of failure from a leak to a rupture, cause development of a condition not detectable by assessment methods in use, or cause the shift of a condition from stable to unstable.

A barrier to accounting for such interactions is the operator's limited ability to recognize when the loading or operating environment may have changed for the worse somewhere along the right-of-way and to quantify the significance of those conditions. Recognizing and quantifying these effects will, in some cases, require integration of information from ILI, ground or aerial patrols, or at some sites, actual monitoring or measurement of changing conditions. This report provides guidance for pipeline operators in the form of advanced interaction matrices, decision processes, and data needs for identifying and evaluating complex or interactive situations.

SCOPE

The scope of the project involved:

- A literature review to assess what has been published previously in terms of identifying and dealing with interacting threats
- A review of "reportable" incidents to determine the types and frequencies of incidents caused by interacting threats

- An analysis to determine which interacting threats caused significant numbers of incidents
- Formulation of procedures to evaluate the significant threat interactions and consider mitigative responses to reduce the risk of a pipeline failure from such threat interactions
- Identifying analytical tools for operators to use in applying mitigative responses

The results of these activities were summarized previously in three interim reports: a Task II.A report, a Task II.B report, and a Task II.C report.

The purpose of the Task II.A report was to identify the most likely threat interaction circumstances. The first step was to review the prior information on interacting pipeline threats to help identify the different types of possible interactions. Task II.A.1 consisted of a literature review that covered recognized pipeline integrity management practices, both of a general nature and for specific threats. This was followed by an analysis of the pipeline failure data to define the frequencies of incidents involving such interaction mechanisms (Task II.A.2). Finally, the most frequent interactions were described in detail to support the analysis in the additional tasks of this project (Task II.A.3).

The purpose of the Task II.B report was to develop a guidance procedure for identifying each relevant threat interaction established in Task II.A. The resulting reference sheets are intended to assist pipeline operators in addressing interacting threats in their integrity management plans.

The Task II.C report consisted of a review of fitness-for-service assessment methods and criteria currently in usage for evaluating defects under complex loading systems. Existing analytical models for addressing many of the situations of concern were presented and explained. Examples using representative data on defect size, applied stress, material properties, and degradation rates were provided.

This final report ties together these previous interim reports.

LITERATURE REVIEW

Definition of Interacting Threats

DNV RP-F116 [1] defines the term “threat” as *an indication of an impending danger or harm to the system, which may have an adverse influence on the integrity of the system* and also as *the root causes that may lead to failure*. CSA Z662-11 [2] uses the term “hazard” rather than “threat” and defines it as *a condition or event that might cause a failure or damage incident or anything that has the potential to cause harm to people, property, or the environment*.

The definition of pipeline threat used in this project combines elements from the above two definitions, as follows:

> ***"The initiating condition or event leading to loss of containment (LoC) in the pipeline system."***

By consensus pipeline operators in the U.S. accept that there are 22 "root causes" of pipeline accidents.[1] These 22 basic causes were identified from studies of "reportable incident"[2] data sponsored by the Pipeline Research Council International (PRCI). Leaving out "unknown" and "miscellaneous" which are of little help in integrity assessment, one arrives at the following 20 basic causes (in effect, threats) that are usually considered in an integrity management plan:

1. External Corrosion (EC)
2. Internal Corrosion (IC)
3. Stress Corrosion Cracking (SCC)
4. Defective Pipe (DP)
5. Defective Pipe Seam (DPS)
6. Defective Fabrication Weld (DFW)
7. Defective Girth Weld (DGW)
8. Construction Damage (CD)
9. Malfunction of Control or Relief Equipment (MCRE)
10. Stripped Threads, Broken Pipe, or Coupling Failure (TSBPC)
11. Gasket Failure (GF)
12. Seal or Pump Packing Failure (SPPF)
13. Incorrect Operations (IO)
14. Third Party Damage (TP)
15. Previously Damaged Pipe (PDP)

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[1] Certain key reference documents, including DNV RP-F116 and ASME B31.8S refer to the failure classifications associated with integrity threats as "root causes". The authors of this study have chosen to substitute the term "basic cause" to recognize the distinction between a causal physical condition or event from a true "root cause" as identified by an accident investigation. Mechanical or metallurgical failures have causal factors or events, perhaps with underlying causes and contributing factors. Consider for example, an external corrosion failure. Why did corrosion occur? Physically, in order for external corrosion to occur, both coating failure and cathodic protection (CP) failure had to be present as immediate causal factors at the same time and location. Why did the coating and CP barriers fail? Possible underlying factors will vary with circumstances and may in fact be what are recognized in this report as "interacting threats", for example indentation of the pipe by a rock in the ditch bottom. The effects of the rock are that it damages the coating, holds moisture against the exposed metal, and interferes with cathodic protection, which are contributing factors. However, none of these underlying causes or contributing factors is a "root cause". A "root cause" is a failure of one or more management or control systems such as specifications, communication, training, procurement, or procedures, and that is (are) in the power of management to correct. The root causes are associated with how the pipe came to be installed on a rock that could cause damage. There are many possible root causes of corrosion in a rock dent that are usually not identifiable from DOT reportable incident narratives or specialist metallurgical failure analyses. Root causes can only be determined from a formal root cause analysis process that examines all possible direct causes, underlying causes, contributing factors, nonfactors, and decision processes that led to a loss event.

[2] A reportable incident is one which meets the definitions of incident severity specified in the Code of Federal Regulations Parts 192 and 195.

16. Vandalism (V)
17. Earth Movement (EM)
18. Heavy Rains and Floods (HRF)
19. Lightning (LIGHT)
20. Cold Weather (CW)

Considering which of these 20 threats exists for a given pipeline segment and providing for mitigative responses to minimize the probability of failure from each identified threat is what integrity management plans are supposed to do. However, integrity management plans should also consider situations where one or more of these threats could interact resulting in a higher probability of failure than that associated with each of the individual threats. Consideration of interactions is required by ASME B31.8S, §2.2, which cites the threat pair of corrosion and third-party damage as examples of interacting threats. Third-party mechanical damage can be a threat by itself as can external corrosion. But if external corrosion occurs at an area of mechanical damage, it is possible that a failure is more likely from the combined threats than from either of the two threats alone.[3]

The following definition of interacting threats, developed for a recent Kiefner project [3], has been adopted for this project:

> ***"Two or more threats acting on a pipe or pipeline segment that increase the probability of failure to a level greater than the effects of the individual threats acting alone."***

In order for threats to be interacting, they must act concurrently and coincidentally to cause a condition or situation that is more severe than that created by individual threats. It is important to note that threats are not necessarily interacting simply because they exist at the same location on a pipe or pipeline.

One of the threats that tends to cause confusion as to whether or not an interaction of two or more threats has caused an incident is the threat associated with incorrect operations (IO). For the purpose of this project, the following definition is used for the IO threat:

> ***Incorrect pipeline operation means an action or inaction by the pipeline operations team that results in loss of containment in the pipeline system.***

[3] The interacting nature of corrosion and mechanical damage consisting of a scrape or gouge is debatable. The presence of corrosion does not increase the likelihood of the pipeline being hit by an excavator and the scrape or gouge does not necessarily increase the likelihood of corrosion occurring over and above any other source of coating damage. The presence of a scrape or gouge is sufficient to pose an immediate threat without corrosion being present. On the other hand, corrosion and damage from rocks may pose a more serious interaction because the area of damage may affect a larger area, the rock may trap moisture against the pipe, and the rock may interfere with cathodic protection.

By this definition random errors such as failure to identify an anomaly from an in-line inspection cannot be construed as an incorrect operation because the identification failure could have originated with the inspection device, the inspection vendor's data analysis process, or the inspection results reporting process. On the other hand, failing to account for tool error or flaw growth rates with respect to identified anomalies, leading to a pipeline failure, is operator error.

Another challenge is to identify when loss of containment appears to have resulted from a single cause or threat but, in reality, has resulted because of circumstances that aggravated the threat. As will be seen, the concept of an aggravated threat was evident in some of the literature reviewed during this project. For example, a pipe seam anomaly passes an initial hydrostatic test but fails after a period of years in service from growth resulting from pressure-cycle-induced fatigue. Fatigue is not one of the twenty threats listed above, yet it certainly contributes to the incident. Note that pressure-cycle-induced fatigue is listed as a threat in the API RP 1160 (2013) even though it is not one of the 20 threats addressed in ASME B31.8S.[4] As another example of an aggravated threat suppose that a pipeline is exposed to the threat of external corrosion and because of a change in operating conditions (such as an upgrading of its maximum allowable operating pressure or an increase in its operating temperature), the probability of a failure caused by external corrosion may increase in the absence of suitable mitigation.

In addition to the significant interacting threats identified in this report, there is a need to consider aggravated threats in an integrity management plan. In general, several of the 20 recognized threats can be aggravated if the following circumstances exist:

- Significant Bi-axial stress is present. That is, a high level of axial stress is present in addition to the normally expected hoop stress arising from internal pressure.
- Cyclic loading exists that can lead to fatigue crack initiation or fatigue crack growth of existing imperfections.
- Monotonically increasing external loading develops from factors such as frost heave, settlement, or the addition of extra above-ground loads.
- Time-varying environmental factors such as a change in temperature, a change in soil moisture, a change in cathodic protection or changes in the nature of the transported fluid can cause stable situations to become unstable (i.e., worsen, spread, or enlarge) leading to an increased probability of an incident.

As will be seen, each identified aggravated threat will be addressed by defining it as an interaction of two of the 20 individual threats.

[4] The differing integrity threats listings reflect the differing characteristics of natural gas and hazardous liquid pipelines.

Threat Interaction Cases Identified via the Literature Search

Thirty-two (32) cases of threat interactions were identified for pipelines and four cases of threat interactions were identified for facilities. Appendix A presents the individual review of each of the bibliographical references and a description of all 36 identified interacting threats.

The following observations from the literature review can be made:

- API RP 1160 (2013) recognizes 11 threat interactions:[5]
    1. Selective seam-weld corrosion (EC + DPS) or (IC + DPS)
    2. Narrow axial external corrosion (EC + DP)
    3. External corrosion and previously damaged pipe (EC + PDP)
    4. Hydrogen Blistering (IC + DP)
    5. Pressure-cycle-induced fatigue of manufacturing defects (DP aggravated) or (DPS aggravated).
    6. Pressure-cycle-induced fatigue of construction defects (CD aggravated)
    7. Pressure-cycle-induced fatigue of previously damaged pipe (PDP aggravated)
    8. Stress corrosion cracking in previously damaged pipe (SCC + PDP)
    9. Stress corrosion cracking/pressure-cycle-induced fatigue (SCC aggravated)
    10. Hard spots and hard heat-affected zones exposed to atomic hydrogen (DP aggravated) or (EC + DP)
    11. Girth welds exposed to excessive axial loading (DGW + EM) or (DGW + HRF)
- ASME B31.8S recognizes four threat interactions. These interactions are the same as four of the 11 interactions mentioned in API RP 1160.
    - Selective seam-weld corrosion (EC + DPS) or (IC + DPS)
    - External corrosion and previously damaged pipe (EC + PDP)
    - Pressure-cycle-induced fatigue of construction defects (CD aggravated)
    - Girth welds exposed to excessive axial loading (DGW + EM) or (DGW + HRF)
- CSA Z662 discusses the need to consider interacting threats without giving specific examples.
- DNV RP F116 discusses the need to consider interacting threats giving the specific example of previously damaged pipe being affected by external corrosion.
- The Pipeline Defect Assessment Manual (PDAM) and a number of technical articles and publications discuss various interacting threats 21 of which 8 did not overlap the 11 threat interactions mentioned in API RP 1160.

[5] Note that some outcomes involve an interaction of an imposed condition or integrity threat with an intrinsic and normally acceptable feature or characteristic of the pipe that by itself does not represent a threat to integrity. For example, Item 2 involves external corrosion acting at the toe of a DSAW seam, and typically a gap under the coating adjacent to the seam. However, the seam toe alone is an acceptable pipe feature. Item 4 involves a source of hydrogen (either from internal corrosion associated with sour service, or cathodic charging) acting on inclusions within the layered microstructure of the steel. The inclusions alone are usually benign except when acted on by a buildup of diffusible hydrogen.

1. External or internal corrosion subjected to severe compressive longitudinal loading (EC aggravated) or (IC aggravated), leading to buckling of the thinned wall.
2. Circumferential external or internal corrosion subjected to monotonically increasing axial loading in tension (EC + EM) or (IC + EM).
3. Previously damaged pipe subjected to monotonically increasing axial loading (PDP + EM).
4. Previously damaged pipe affected by bending loads (PDP + IO) not correctly accounted for in the design of the pipeline.
5. Previously damage pipe affected by cyclic bending loads, thermally-induced stresses or vibrations (PDP aggravated).
6. Manufacturing defect subjected to severe compressive longitudinal loading (DP aggravated) or (DPS aggravated).
7. Manufacturing defect subject to cold weather (DP + CW) or (DPS + CW).
8. Manufacturing defect affected by nearby welding (DP + DFW) or (DPS + CW).
9. Stress corrosion cracking affected by changes in environmental conditions (SCC aggravated).
10. Stress corrosion cracking in circumferential direction (SCC + EM).
11. Stress corrosion cracking aggravated by excessive cathodic protection or excessive operating temperature (SCC + IO).
12. Stress corrosion cracking facilitated by residual stress from manufacturing or construction (SCC + DP) or (SCC + CD).
13. Pipe seam defect aggravated by environmental conditions (DPS aggravated).
14. Pipe seam defect in pipeline with inadequate hydrostatic test (DPS + IO).
15. Defective girth weld subjected to vortex shedding resulting from inadequate design or construction (DGW + IO).
16. Wrinkle bend subjected to pressure-cycle-induced fatigue (CD aggravated).
17. Wrinkle bend subjected to external corrosion (CD + EC).
18. Failure to adequately monitor ground movement (EM + IO).
19. Failure to monitor unique repeated external loads (DPS + IO) or (DGW + IO).
20. Pipe with external or internal corrosion subjected to pressure-cycle-induced fatigue (EC aggravated) or (IC aggravated).
21. External or internal corrosion in conjunction with stress corrosion cracking (EC + SCC) or (IC + SCC).

- PPTS Advisory 2009-5 (Liquid Pipeline Facilities threats)
    1. Construction related circumstances aggravated by design errors and vibrations.
    2. Internal corrosion resulting from poor design or layout of tubing.
    3. Cold weather leading to freezing of accumulated water.
    4. Internal corrosion as the result of poor inspection processes.

- Equipment failure and/or malfunction (MCRE, TSBC, GF and TSBPC) were not considered in the literature reviewed. The review did not reflect the interaction of construction defects (DFW, DGW and CD) with the time dependent threats (EC, IC and SCC) and equipment failures. Construction defects were only considered to interact with manufacturing defects and soil movement/instability.
- In the literature reviewed, third party damage (TP) was only considered to interact with incorrect operations (IO); the interaction with time dependent and stable threats was not considered.

Aggravated Threats

Through the literature review it is apparent that industry experts have recognized aggravated individual threats as being distinct from the individual threats themselves. For example, a seam manufacturing threat (DPS) might be considered stable in a reasonably steady-state operating pressure regime after a hydrostatic test to a test-pressure-to-operating-pressure ratio of 1.25. In fact, both B31.8S, §7.3.3 and 49 CFR §192.917 indicate that pipe manufacturing related integrity threats may be considered stable if the MAOP has not been increased or the maximum operating pressure has not increased above a 5-year historical level. One unintended effect of these declarations may be some operators becoming lulled into believing that if the operating pressure does not increase, transient operation has no effect. However, if the operating regime actually involves frequent large swings in pressure, a seam manufacturing defect may grow large enough to cause a failure at the operating pressure after a period of time. This circumstance was identified in some of the references discussed above and was labeled “DPS aggravated”. A second unintended effect may be that some operators focus exclusively on pressure effects while overlooking the fact that changes in product quality, throughput rates, coating integrity, cathodic protection levels, or geotechnical conditions may also affect pipe manufacturing flaws. Certainly, the potential for this to happen must be recognized in an integrity management plan. This aggravated threat and others are discussed below.

Pressure-Cycle-Induced Fatigue

Pressure-cycle-induced fatigue is probably the most significant aggravating factor. It can cause anomalies such as seam or pipe manufacturing defects which are too small to cause failures in a hydrostatic test to grow to failure at a later time after the test (DPS aggravated or DP aggravated). Similarly, it can cause initially non-injurious defects such as small corrosion pits, small stress corrosion cracks, dent or gouges left over from construction, or dents and gouges created in service to grow to failure over time (EC aggravated, IC aggravated, SCC aggravated, CD aggravated, or PDP aggravated).

Other Fatigue

Previously damaged pipe can also be caused to fail if significantly affected by cyclic bending loads, thermally-induced stresses or vibrations (PDP aggravated).

External Loading

Another significant aggravating factor is unusual or excessive external loading, which may develop after an extended period of benign conditions. For example, a pipeline subjected to severe compressive longitudinal loading could lead to buckling of a corrosion-thinned wall (EC aggravated or IC aggravated) or to the failure of a manufacturing defect (DP aggravated or DPS aggravated). Pipelines operating at low or moderate hoop stress levels (below 60% of SMYS) are generally deemed to be non-susceptible to SCC, per ASME B31.8S, §5.10 and §A-3.3. However, slope movement, frost heave, or subsidence acting on a pipeline deemed to be non-susceptible to SCC by virtue of operating at a low hoop stress may induce axial tension sufficient to exceed thresholds for transverse SCC.

Increased Operating Temperature and Corrosion

Some threats can be aggravated as the result of a change in operating conditions or the operating environments. In particular, these include EC aggravated, IC aggravated, or SCC aggravated. Examples of changes in operating conditions or environments include: changing temperature, changing cathodic protection, cyclic loading, and changes in external loading. The changes may cause conditions considered stable to no longer remain stable. Increased cathodic protection current can lead to failures of hard spots or hard heat-affected-zones if the charging rate of atomic hydrogen becomes excessive.

Increasing throughput of gas or crude oil involves additional energy input to the fluid and an increased friction of flow inside the pipe due to the greater flow velocity. These effects may increase the temperature of the fluid and of the line pipe. Reversal of flow direction may also subject pipeline segments formerly near a pump or compressor suction to the higher discharge temperature of the reconfigured pump or compressor discharge.

Other threats can potentially interact with existing but normally acceptable, benign, or controllable conditions to produce greater rates of degradation or new susceptibility to degradation. These include:

- Degradation of the integrity or performance of coatings. Elevated operating temperatures can reduce the performance of some coating systems. Plastic tape wraps, polyethylene shrink sleeves, asphalt, and non-plasticized coal tar enamel coatings are most susceptible.

- Increased rate of corrosion. The dependence of the equilibrium reduction or oxidation potential on concentration increases with temperature. Also, temperature accelerates chemical reactions, and increases diffusion rates. On the other hand, increasing temperature decreases solubility of oxygen which tends to reduce corrosion rates. While corrosion rates are affected by many environmental factors, they have been observed to increase in simulated environments and in the field in the soil environment, atmospheric environments, internal environments, and some microbial environments depending on species.
- Decreased effectiveness of CP. At elevated temperatures the level of cathodic protection (CP) current necessary to achieve sufficient protection levels is higher than at lower temperatures. Some pipeline operators increase the level of protection from -850 mV to -900 or -950 mV at temperatures above 50 C (122°F).
- Increased susceptibility to high-pH SCC. Tests and operating experience has shown a strong dependence of the probability of failure due to high-pH SCC on operating temperature. Crack growth velocity and density of crack colony formation increase with increasing temperature. Also, the narrow band of potentials where high-pH SCC takes place becomes larger at higher temperatures and the lower potential limit for cracking shifts toward the negative. Thus an increased operating temperature can create a susceptibility that did not previously exist.
- Increased susceptibility to sulfide stress cracking in sour service. Susceptibility is affected by hydrogen permeation rates, which increase with temperature.

Change in Operating Temperature and Structural Stability

Altering the mode of operation (change of product, increased throughput, flow reversal) could result in a change in the operating temperature of the pipeline to a warmer or colder temperature than was considered in the original design of the pipeline. Changes in operating temperature can have the following effects:

- Increase in thrust forces at field bends. The thrust forces may exceed the bearing capacity of weak soils resulting in flexure of the bend and formation of wrinkles. Cyclical thrust forces at bends may also cause pipe to ratchet out of the ground.
- Increase in thrust forces at transitions from below ground to above ground. The resulting thrust forces at transitions may necessitate installation of anchors. Thrust forces may also cause movement of valve settings or failure of above-ground supports.
- Unintended effects on unrestrained piping. Increased axial compression can cause beam-column instability in excavations of buried pipe exceeding a critical length. An expanded range of differences between minimum and maximum operating temperatures may cause above-ground piping to violate piping flexibility design limits, or cause support reaction forces to exceed design capacity.

The authors are acquainted with instances of damage or failure incurred by pipelines as a result of each of the mechanisms listed above.

Changes in Gas Source or Quality

Changes in gas quality can induce unexpected conditions with the potential for leaks. Some operators of natural gas transmission systems in the northeastern U.S. traditionally took gas from U.S. underground storage with predictable moisture content. When Canadian supplies became available, some receiving operators experienced widespread leaks from components involving gaskets or seals due to the extreme dryness of the gas. Many of those same systems are now receiving gas from eastern U.S. shale gas producers with significantly higher content of both moisture and solid particles, which can induce erosion inside high-velocity components such as elbows or reducers in meter and regulator facilities.

Increased susceptibility to the failure of hard spots or hard heat-affected-zones can result from atomic hydrogen from sour gas.

Some operators have experienced increased internal corrosion after reducing the frequency of running internal cleaning tools. This particular change in operation may give rise to unexpected, unplanned for, or undetected conditions that may lead to operational or safety problems despite no change in the pipeline operating pressure or mode of operation.

Converting Aggravated Threats to Interacting Threats

To simplify the guidance for operators which this report is intended to provide, the identified cases of aggravated threats will be redefined as interactions of two or more of the 20 individual threats discussed previously. In the case of any defect that is not large enough to cause an immediate failure but could cause a failure at a later time if caused to grow by pressure-cycle-induced fatigue, the aggravated threat from the defect (whether it be CD, DP, DPS, EC, IC, PDP, or SCC) will be defined as the interaction of the threat with the threat of incorrect operations (IO). The rationale for this definition is that the aggravated threat can be mitigated by periodic hydrostatic testing, in-line-inspection, or direct assessment and that failure of an operator to recognize and monitor the potential for defect growth and apply the appropriate remedies in a timely manner constitutes incorrect operation. Hence, the following aggravated individual threats are transformed to the following interacting threats.

- CD aggravated by pressure-cycle-induced fatigue becomes CD + IO.
- DP aggravated by pressure-cycle-induced fatigue becomes DP + IO.
- DPS aggravated by pressure-cycle-induced fatigue becomes DPS + IO.
- EC aggravated by pressure-cycle-induced fatigue becomes EC + IO.
- IC aggravated by pressure-cycle-induced fatigue becomes IC + IO.

- PDP aggravated by pressure-cycle-induced fatigue becomes PDP + IO.
- SCC aggravated by pressure-cycle-induced fatigue becomes SCC + IO.
- Wrinkle bend subjected to pressure-cycle-induced fatigue CD + IO.

Hard spots and hard heat-affected zones exposed to atomic hydrogen (DP aggravated) will be addressed as DP + IO. The rationale is that operators who have pipelines containing materials affected by hard spots or hard heat-affected zones should recognize that excessive cathodic protection voltage and/or internally corrosive conditions leading to hydrogen ion generation at the exterior or interior surface can cause hydrogen stress cracking of these materials. Failure to take appropriate mitigative actions constitutes incorrect operations.

External or internal corrosion subjected to severe compressive longitudinal loading (EC aggravated) or (IC aggravated), leading to buckling of the thinned wall will be addressed as follows. These cases will be considered EC + IO or IC + IO if the compressive stress loading comes from restraint of thermal expansion and the operator has failed to account for the effect of the built-in stress. Cases of reduced failure stress resulting from external loading such as earth movement will be defined as EC + EM or IC + EM.

Previously damaged pipe affected by cyclic bending loads, thermally-induced stresses or vibrations (PDP aggravated) will be addressed as PDP + IO. Failure to recognize the risk of early failure of previously damaged pipe from such loading conditions and to take appropriate mitigative action constitute incorrect operations.

The failure stress levels of manufacturing defects located in pipelines subjected to severe compressive longitudinal loading (DP aggravated) or (DPS aggravated) can be lower than conventional failure models that do not account for the effects of axial compression might suggest. The operator should take the possibly reduced failure stress levels into account when monitoring pipelines for manufacturing defects. Failure to do so in pipelines with compressive longitudinal loading from restraint of thermal expansion constitutes incorrect operations. Hence, these situations will be defined as DP + IO or DPS + IO. In pipelines with compressive longitudinal loading from earth movement these situations will be defined as DP + EM or DPS + EM.

Stress corrosion cracking affected by changes in environmental conditions (SCC aggravated) will be defined as SCC + IO if the changes are the result of changes in operating conditions and the operator has not considered enhanced mitigative responses. Alternatively, if the environmental changes result from earth movement, SCC aggravated will be defined as SCC + EM.

Pipe seam defect aggravated by environmental conditions (DPS aggravated) will be defined as DPS+ IO because operators should consider the effects of changing environmental conditions

on the probability of failure of pipe seam defects and take appropriate mitigative actions. Alternatively, if the environmental changes result from earth movement DPS aggravated will be defined as DPS + EM.

A Matrix of Interacting Threats

In the past, Kiefner developed a matrix for the Northeast Gas Association (NGA) to identify which threats could potentially interact under which circumstances. The threat interactions were first identified by the subject matter experts (SMEs) and were later evaluated with a review of reportable incident data. The resulting matrix is reproduced in Table 1 and shows 190 possible interactions of which only 98 were thought by the authors to be reasonably possible. (The authors placed "1" in each cell of Table 1 where it was believed that interaction could be reasonably possible based on considering causation mechanisms as informed by knowledge of events). Several possible interactions were highly conditional.

Table 1. Interacting Threat Matrix [3]

			Time-Dependent			Stable									Time-Independent							
			EC	IC	SCC	MFR		CON			EQ				IO	TPD			WROF			
			EC	IC	SCC	DP	DPS	DFW	DGW	CD	MCRE	TSBPC	GF	SPPF	IO	TP	PDP	V	EM	HRF	LIGHT	CW
	EC	EC			1	1	1		1	1[1]	1	1[3]	1		1	1	1		1	1		1
	IC	IC				1	1		1		1		1		1		1					
	SCC	SCC				1	1	1	1	1[4]	1				1		1		1	1		
	MFR	DP					1	1	1	1	1[2]					1[7]	1[7]	1[7]				
		DPS								1[5]	1[2]				1[6]	1[7]	1[7]	1[7]	1			
	CON	DFW										1			1	1			1	1		1
		DGW								1	1					1	1		1	1		1[8]
		CD									1[2]	1							1	1		
	EQ	MCRE										1	1	1	1	1	1			1	1	1
		TSBPC													1	1			1	1		1
		GF													1	1		1	1	1	1	
		SPPF													1							
	IO	IO														1	1	1	1	1		1
	TPD	TP															1		1	1		
		PDP																	1	1		
		V																				
	WROF	EM																		1		1
		HRF																				1
		LIGHT																				
		CW																				

Footnotes:

1. A 1 applies unless the history of the segment indicates the construction damage has not contributed significantly to corrosion.
2. A 1 applies if the segment has not been subject to a pressure test to at least 1.25 times MAOP.
3. A 1 applies if the Dresser-coupled segment has no CP or has CP but no bonds across the Dresser couplings.
4. A 1 applies unless it can be shown either that little or no coating damage exists or that the segment is not susceptible to SCC.
5. A 1 applies if the pipe is seam-welded and was installed with wrinkle bends
6. A 1 applies if the pipe was manufactured with low-frequency welded ERW seam or flash welded seam.
7. A 1 applies unless it is known that the pipe material exhibits ductile fracture behavior under all operating circumstances.
8. A 1 applies only to pipe joined by acetylene girth welds or girth welds of known poor quality.

The threats considered in the NGA Interacting Threat Matrix were the same 20 threats as from B31.8S discussed previously.

The middle bars on the left side and top of Table 1 consolidate the 20 basic causes into nine threat categories for the purpose of the NGA project. These nine threat categories were further consolidated into three groups represented by the shaded bars on the left side and top of Table 1: time-dependent threats, stable threats, and time-independent (i.e., random event) threats. The time-dependent, stable, and time-independent groupings are the same as those adopted in ASME B31.8S. However, ASME B31.8S uses nine threat categories consisting of the following:

1. External Corrosion
2. Internal Corrosion
3. Stress Corrosion Cracking
4. Manufacturing-related Defects
5. Welding/Fabrication-related Defects
6. Equipment
7. Third-party/Mechanical Damage
8. Incorrect Operations
9. Weather-related and Outside Force

PIPELINE FAILURE DATA REVIEW

Kiefner reviewed the DOT pipeline incident data and its own database of failure investigations to identify failures that involved interactive threats (cases where more than one threat occurred on a section of pipeline at the same time). The scope of the review of the DOT incidents included:

- Natural gas (GAS) pipeline incidents (1985 through December 2015)
- Hazardous liquids (HL) pipeline incidents (1986 through December 2015)

Possible interactions causing DOT reportable incidents were selected and counted based on the Interacting Threat Matrix presented previously. It is important to note that the *Wrinkle Bends and Buckles* category reported in early works has been expanded and renamed Construction Damage (CD). Construction damage includes Wrinkle Bends,[6] Buckles, Construction Dents, and Gouges. This differentiates dents and gouges inflicted during construction from delayed failure from previously damaged pipe (PDP) and from immediate failures caused by third parties (TP).

[6] Prior to the development of cold-bending equipment, around 1955, field bends in large-diameter pipe were made by intentionally buckling the pipe under controlled conditions while bending the pipe as means of foreshortening the inside meridian of the bend. The wrinkles were acceptable features and not considered defects, but are now viewed as potentially harboring damage.

Lastly, Kiefner's database of failure investigations was reviewed using the Interacting Threat Matrix to see if it reinforced the findings of the review of DOT reportable incidents regarding incidents caused by interacting threats.

DOT Reportable Hazardous Liquids Incidents

Kiefner reviewed 8,468 incidents in HL lines (reported from 1986 through 2015); 527 incidents (approximately 6% of the HL incidents) were considered to contain information implicating interactive threats. Five hundred and seventy-one (571) threat interactions were identified. The fact that the number of threat interactions exceeds the number of incidents simply means that some incidents involved more than two interacting threats. Table 2 presents the results for hazardous liquids transmission lines.

Table 2. Incidents from Interacting Threats for HL Transmission Lines – DOT Incident Data

	Hazardous Liquids Transmission Lines - DOT Incident Database 1986-2015																					
	EC	IC	SCC	DP	DPS	DFW	DGW	CD	MCRE	TSBPC	GF	SPPF	IO	TP	PDP	V	EM	HRF	LIGHT	CW	MISC	Total
EC		2	1		31	4	6	49	2	3			21		11		1	2				133
IC					2	2	5		1	3	1		3									17
SCC					2	2	1	1					2		1		1					10
DP					1								5				2			1		9
DPS								1	1				11				1					14
DFW							1			1			17	1	1		1	1		1		24
DGW								1					5				10	7		1		24
CD										1			1				4			4		10
MCRE											1	1	18	3					1	27	1	52
TSBPC											2		47	36			14	14	1	14	1	129
GF													37					1		2	1	41
SPPF													7						1	1	1	10
IO														24	7		2	5	1	24	2	65
TP																	2	13				15
PDP																		1				1
V																						0
EM																		15		1		16
HRF																				1		1
LIGHT																						0
CW																						0
																						571

DOT Reportable Natural Gas Incidents

Kiefner reviewed 2,716 incidents in natural gas pipelines (reported between 1985 and 2015). Interacting threats were involved in 306 (approximately 12%) of the incidents; this is double the percentage for HL lines (6%). Table 3 presents the summarized results for gas transmission and gathering lines. As indicated in Table 3, 331 threat interactions were identified. The fact that the number of threat interactions exceeds the number of incidents involving threat interaction simply means that some incidents involved more than two interacting threats.

Table 3. Incidents from Interacting Threats for GAS Transmission Lines – DOT Incident Data

	Gas Transmission and Gathering Lines - DOT Incident Database 1984 - 2015																					
	EC	IC	SCC	DP	DPS	DFW	DGW	CD	MCRE	TSBPC	GF	SPPF	IO	TP	PDP	V	EM	HRF	LIGHT	CW	MISC	Total
EC			1	1	14		4	3	5	2	2		6		4		1	1		2		46
IC					11		8		3													22
SCC				1																		1
DP								2	1												1	4
DPS									1								1				1	3
DFW										1			1	2			5	1		1	2	13
DGW								1	1				1	2			19	11		2	3	40
CD										2							3	1				6
MCRE										5	4	1	11	2			1	5	7	33	3	72
TSBPC													6	11			17	18		3	1	56
GF													8	2		1	1	2	2		1	17
SPPF																						0
IO														7	1					2	1	11
TP															2		2	17				21
PDP																	1	1				2
V																						0
EM																		14		1		15
HRF																				2		2
LIGHT																						0
CW																						0
																						331

Combined DOT Reportable Hazardous Liquid and Natural Gas Incidents

The numbers of each type of incident caused by interacting threats for hazardous liquid and natural gas incidents combined are presented in Table 4. The gas and liquid incidents were combined in Table 4 with the recognition that reporting requirements differ for the two types of pipeline system and that reporting requirements in both types of systems have changed several times over the years. Nevertheless, it simplifies the following analysis to deal with all incidents to establish which types of interaction might be important for integrity management planning and which might not be.

Table 4. Incidents from Interacting Threats for GAS and HL Transmission Lines – DOT Incident Data

	Total Incidents for Hazardous Liquids and Gas Lines - DOT Incident Database 1986-2015																					
	EC	IC	SCC	DP	DPS	DFW	DGW	CD	MCRE	TSBPC	GF	SPPF	IO	TP	PDP	V	EM	HRF	LIGHT	CW	MISC	Total
EC		2	2	1	45	4	10	52	7	5	2		27		15		2	3		2		179
IC					13	2	13		4	3	1		3									39
SCC				1	2	2	1	1					2		1		1					11
DP					1			2	1				5				2			1	1	13
DPS								1	2				11				2				1	17
DFW							1			2			18	3	1		6	2		2	2	37
DGW								2	1				6	2			29	18		3	3	64
CD										3			1				7	1		4		16
MCRE										5	5	2	29	5			1	5	8	60	4	124
TSBPC											2		53	47			31	32	1	17	2	185
GF													45	2		1	1	3	2	2	2	58
SPPF													7						1	1	1	10
IO														31	8		2	5	1	26	3	76
TP															2		4	30				36
PDP																	1	2				3
V																						0
EM																		29		2		31
HRF																				3		3
LIGHT																						0
CW																						0
																						902

From the incident count, it is apparent that many threats did not interact to cause incidents. These are the interactions that correspond to the 90 blank spaces out of the 190 possible interactions (excluding those in the "Miscellaneous" column) in Table 4. Many more interactions appeared as causes only a few times in 30 years of operation of hundreds of thousands of miles of pipelines. The frequencies with which the various interacting threats caused incidents are illustrated graphically in Figure 1.

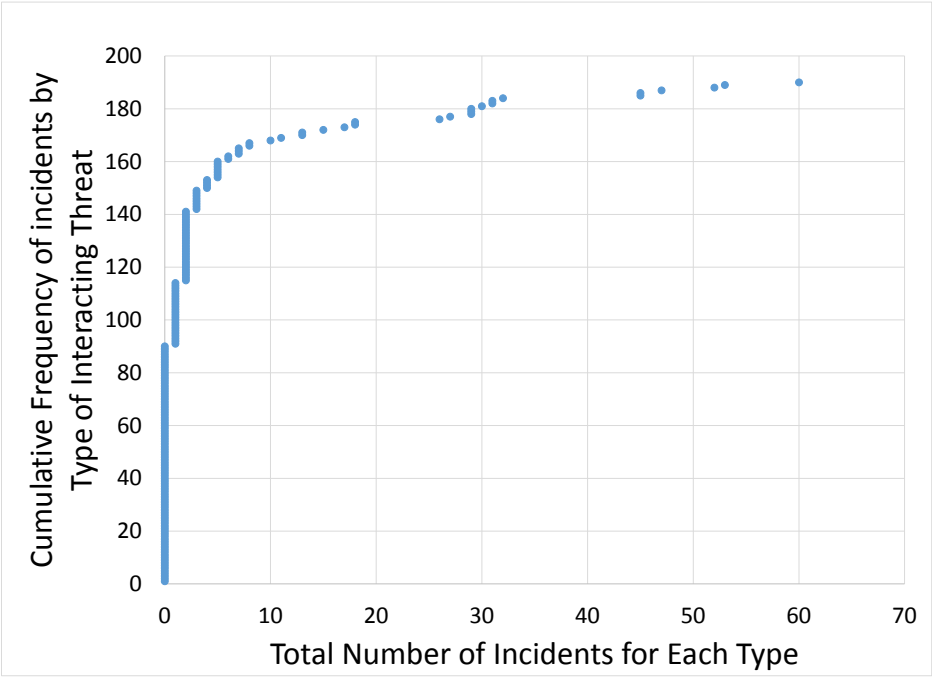


Figure 1. Cumulative Frequencies of Incidents from Various Types of Interacting Threats

Figure 1 shows the cumulative distribution of the number of incidents by type of interacting threat for all 190 possible interactions. No incidents are shown for 90 possible theoretically interactions. These no-incident threat pairs correspond to the blanks in Table 4. Eight or fewer incidents were observed for 167 of the possible interactions (including the 90 interactions for which no incidents were observed). The remaining 23 threat interactions are presented in Table 5. The threats are presented in descending order of HL + GAS count.

Table 5. Interacting Threats that Account for 75.5% of the Incidents Caused by Threat Interactions

Interaction Number	Type of Interaction	HL Count	GAS Count	HL+GAS Count
1	MCRE+CW	27	33	60
2	TSBPC+IO	47	6	53
3	EC+CD	49	3	52
4	TSBPC+TP	36	11	47
5	EC+DPS	31	14	45
6	GF+IO	37	8	45
7	TSBPC+HRF	14	18	32
8	TSBPC+EM	14	17	31
9	IO+TP	24	7	31
10	TP+HRF	13	17	30
11	DGW+EM	10	19	29
12	MCRE+10	18	11	29
13	EM+HRF	15	14	29
14	EC+IO	21	6	27
15	IO+CW	24	2	26
16	DFW+IO	17	1	18
17	DGW+HRF	7	11	18
18	TSBPC+CW	14	3	17
19	EC+PDP	11	4	15
20	IC+DPS	2	11	13
21	IC+DGW	5	8	13
22	DPS+IO	11	0	11
23	EC+DGW	6	4	10
Incidents with >8 occur.		453	228	681
Percentage of all incidents		5.35	8.39	6.09

For the purpose of this project, which is to provide guidance for pipeline operators for their responses to interacting threats in their integrity management plans, the focus will be on these 23 interacting threats. With one exception, which is discussed below, the remaining 167 possible interacting threats will not be included in the guidance because they appear to entail a low probability of causing pipeline failure incidents.

General Observations Concerning the Reportable Incident Data

Some threat interactions were simply a result of where the damage or failure occurred rather than a complex interaction of failure mechanism(s). For example, failures due to third-party

(mechanical) damage that occurred in the pipe were not an interacting threat, but if the damage involves a threaded nipple or fitting, it is an interaction of threats. Another example would be failures due to external loading from soil movement. If the pipeline fails in the pipe body or sound girth weld, it is not interacting, but if the pipe fails at a defective girth weld, coupling, or defective fabrication weld, it is a case of interacting threats. In these cases, there is no consideration of the failure stress level or whether the pipeline would have failed if the damage or stress would have occurred in a different location on the pipeline.

After each of these examples was reviewed, some inherent interaction was considered to be present in each. In the case of mechanical damage, it was determined that threaded connections were inherently weaker and therefore more susceptible to failure from damage, both in the likelihood of being damaged as well as being more likely to fail if damaged. The reasons for this were described previously, but include the following observations: 1) threaded joints are weaker than welded joints; 2) threaded joints tend to be smaller in diameter than most pipelines and thus less strong; and 3) threaded attachments tend to be oriented perpendicular to the pipeline, presenting a moment arm for most external forces. In the case of defective girth welds, two factors were identified that make these joints more susceptible to failure than the adjacent pipe body: 1) the shape of the joint itself represents a geometric stress concentrator and 2) the presence of some type of welding defect in an area of concentrated stress would make these joints more susceptible to failure than the mating pipe.

Some interactions seemed to be the result of limitations of the threat definition. The category of “Heavy Rains and Floods” is frequently associated with the type of Earth Movement caused by saturated soils, and mechanical damage associated with airborne debris (e.g., from tornados and storms, which can only affect above-ground piping). Although these are identified as interacting threats (HRF+EM) in the 20-threat approach, there is no interaction in the 9-threat approach because HRF and EM are, by definition, both part of the weather-related or outside force (WROF) threat.

Not all interactions of threats may be apparent from a review of reportable incidents. Several reasons why this may be possible include:

- The cause of failure and contributing factors were unknown at the time of the report.
- The person filing the incident did not have all of the information available.
- The narrative was incomplete or not written in a way for the interaction to be apparent.
- The interaction was not recognized.

These shortcomings are inherent in relying on the reportable incident data. Very likely, an analysis of the reportable incident data underestimates the frequency of occurrence of interactions, and may completely miss some interaction pairs.

Review of Kiefner Failure Investigation Data

The failure analyses that have been performed by Kiefner from 1990 to 2014 were reviewed. In-service and hydrostatic test failures from hazardous liquid and gas transmission pipelines were considered. The review identified 35 cases of threat interactions as having caused failures. The numbers of incidents caused by the various types of interactions are shown in Table 6 below. The two threat interactions causing the most failures were external corrosion and defective pipe seam (EC + DPS) (most, if not all, involved selective seam weld corrosion) which accounted for 10 of the 35 failures (28.5%) and stress corrosion cracking in mechanical damage (SCC + PDP) which accounted for 5 of the 35 failures (14.3%). The interaction between internal corrosion and defective pipe seam (IC + DPS) accounted for 3 failures. The interaction between internal corrosion and defective girth weld (IC + DGW), the interaction between external corrosion and incorrect operations (EC + IO), and the interaction between defective girth weld and earth movement (DGW + EM) each accounted for 2 failures. Nine other interactions were thought to have caused one failure each, and the vast majority of interactions were not implicated in any of the failures in the database. The (DGW + EM) interaction was the fourth leading cause in the DOT Incident Data review. The (EC + DPS) interaction was the fifth leading cause. The (IC + DPS) interaction was the twentieth leading cause, (IC + DGW) was the twenty-first leading cause, and (EC + IO) was the fourteenth leading cause. However, the (SCC + PDP) interaction accounted of only one incident in the DOT Incident Data review (90th in order in that review). The significance of the latter interaction is discussed below.

Table 6. Failures from Interacting Threats from Kiefner Failure Analysis Projects

	Review Kiefner Failure Reports 1990-2015																				
	EC	IC	SCC	DP	DPS	DFW	DGW	CD	MCRE	TSBPC	GF	SPPF	IO	TP	PDP	V	EM	HRF	LIGHT	CW	Total
EC					10				1				2		1						14
IC					3		2								1						6
SCC														1	5						6
DP					1																1
DPS													1								1
DFW								1													1
DGW																	2				2
CD																					
MCRE																				1	1
TSBPC														1							1
GF																					
SPPF																					
IO														1							1
TP																					
PDP																	1				1
V																					
EM																					
HRF																					
LIGHT																					
CW																					
																					35

Stress Corrosion Cracking and Previously Damaged Pipe (SCC + PDP)

SCC has been observed at the perimeter of plain dents and dents associated with mechanical damage. The dent increases the local stresses, sometimes in pipelines whose operating hoop stress is below the level usually considered to be susceptible. The deformation must be sufficient to damage the coating, and the cathodic protection is locally impaired in some way.

(For example, the high resistivity of a rock that has indented the pipe and damaged the coating may also interfere with cathodic current reaching the exposed pipe surface within the indentation.) The increased residual stress associated with the dent or gouge can be sufficient to initiate and grow SCC in these locations.

Because it seems likely that stress corrosion cracking interacting with previously damaged pipe (SCC + PDP) is under-represented in the DOT incident statistics, this interacting threat will be included in the guidance to be developed on this project. That brings the number of types of interactions to be considered to 24.

DEVELOPMENT OF INTERACTING THREAT IDENTIFICATION PROCESSES AND DATA REQUIREMENTS

From the frequency analysis presented in Table 5 and the discussion of the Kiefner failure investigations, it was determined that the threat interactions requiring the development of illustrative narratives and flowcharts, were the 23 interactions presented in Table 5, with the addition of SCC + PDP.

A guidance procedure was developed for every one of the 24 threat interactions. The study of each interaction was as follows:

1. The factors affecting the individual threat and the interaction were studied.
2. The basic causes of the threat interaction were determined.
3. A flowchart[7] for identifying the threat interaction was constructed, taking care of incorporating the basic causes in the logical tests.
4. The data requirements for the threat were discussed.
5. The methods available to assess the pipe or component condition were reviewed, with an emphasis on their scope and limitations.
6. A list of mitigative barriers available to prevent the threats and their interaction were determined.

The definition of mitigative barrier as used herein is as follows:

[7] The project proposal erroneously used the term *decision tree*, which is a sequence chart that lists probabilities of each event. The flowchart required for this work is a diagram with logical test that helps the operator identify the threat interaction.

Elements, components, actions and processes that can prevent or mitigate a LoC in the pipeline system.

A failed mitigative barrier can be an aggravating factor but cannot cause a failure[8] by itself. For example, the failure of an ILI run to detect an anomaly or to characterize it accurately can increase the likelihood of failure from external corrosion, internal corrosion, stress corrosion cracking, a defective pipe, a defective pipe seam, construction damage, or previously damaged pipe. However, the failure to detect is a failure of a mitigative barrier but not a threat by itself.

Many threat interactions share some common elements; for example, EC + DPS and IC + DPS are driven by the same mechanism (SSWC), but have different influencing factors depending on whether the corrosion happens on the outside or the inside surface of the pipe seam. The 24 threat interactions were bundled together if and when the common elements were sufficiently related as follows:

- EC + DPS
- IC + DPS
- EC + CD
- EC +PDP
- EC + IO
- EC + DGW and IC + DGW
- DPS + IO
- DFW + IO
- MCRE + IO
- MCRE + CW
- TSBPC + IO
- TP + IO
- TSBPC + TP
- EM + HRF
- TSBPC + EM and DGW + EM
- TSBPC + HRF and DGW + HRF
- GF + IO
- CW + IO and TSBPC + CW
- TP + HRF
- SCC + PDP

[8] An exception should be made whenever a defective cathodic protection (CP) system actually promotes corrosion in the line (*e.g.* CP electrical connections made with the wrong polarity).

External Corrosion and Defective Pipe Seam (EC + DPS) Interacting Threat Identification

EC+DPS was found to be the fifth leading cause of incidents for interactive threats accounting for 45 incidents. There are three important reasons why EC+DPS, or more appropriately, selective seam weld corrosion (SSWC), is one of the most difficult-to-manage interacting threats:

- The narrow axially-oriented defect is not readily detected by conventional MFL ILI tools and is not accurately characterized (if it is detected) by conventional UT metal loss ILI tools.
- The rate of depth penetration may be 2 to 5 times greater than the rate of penetration in the base metal.
- The condition may lead to rapid development of a critical-size flaw in the ERW seam bond line of the pipe, especially if the bond line region possesses low fracture toughness, or it may lead to failure over a longer period of time in a case where the bond line has good ductility. In either case a rupture at a low stress level is possible.

The likelihood of failure from SSWC depends on the following factors:

- Type of seam. Low-frequency-welded ERW, direct-current-welded ERW, and flash-welded seams should be considered susceptible to SSWC unless there is evidence to show that the seams in a particular pipeline are not susceptible. High-frequency-welded ERW pipe may also be susceptible, especially if its sulfur content exceeds 0.01% and carbon content exceeds 0.1% by weight or the pipe was manufactured before 1985, but the seam region of high-frequency-welded ERW pipe usually has much higher toughness that the seam regions of the other types of pipe. This latter advantage means that defects in the bond line of a high-frequency-welded pipe will be larger and therefore will take longer to grow to failure than those of the other types of pipe.
- Corrosiveness of the soil environment
- Coating condition
- Effectiveness of the cathodic protection system

A pipeline operator may be able to show that the probability of failure from SSWC for a particular pipeline segment is so low that it need not be considered in an integrity management plan. If not however, the existence of any one of the following circumstances would indicate the need to develop a mitigative plan to prevent failures from SSWC:

- The pipeline has sustained external corrosion

- One or more in-service or hydrostatic test failures from either base metal corrosion or SSWC have occurred.
- The coating on the pipeline is in poor condition.
- The cathodic protection is insufficient to satisfactorily mitigate external corrosion.
- Prior ILI runs to detect metal loss show that significant amounts of external corrosion-caused metal loss have occurred.
- SSWC has been identified in prior excavations of corroded areas.
- Linear polarization resistance (LPR) tests of representative seam samples indicates potential susceptibility.

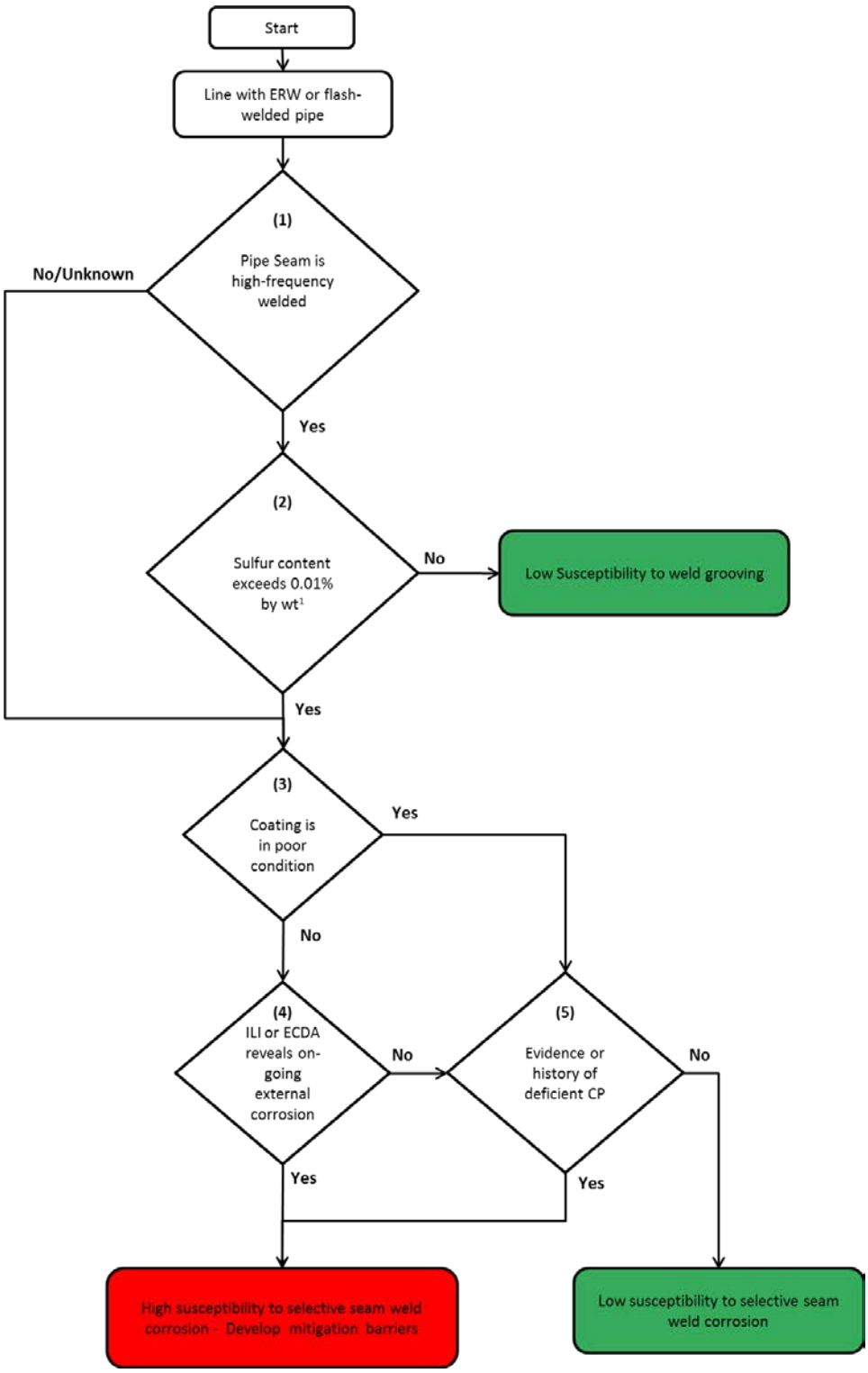
The mitigative plan that should be developed by the operator to prevent failures from SSWC should consist of the following elements:

- Review prior ILI runs for detecting external corrosion-caused metal loss or ECDA data to understand where corrosion has been occurring. Review dig sheets to see if any SSWC was identified.
- Train field personnel to look for and recognize SSWC on exposed pipe.
- Expose some known areas of prior external corrosion that were not repaired to see if SSWC has occurred.
- Estimate the rate of external corrosion from prior digs in response to ILI runs.
- If any SSWC is identified and the segment containing the SSWC can be removed, use metallographic sectioning to establish the grooving ratio, that is, the ratio of maximum corrosion penetration of the wall thickness in the bond line to the maximum penetration of the surrounding base metal.
- Estimate the rate of SSWC by multiplying the rate of corrosion in the base metal by the grooving ratio.
- Conduct an ILI run using a tool that is capable of identifying and characterizing SSWC anomalies such as a circumferential-field magnetic-flux leakage (CMFL) tool.
- Conduct an ILI run using a longitudinal-field MFL tool as is done normally for metal loss in the body of the pipe.
- Compare the results of both types of inspection to maximize the ability to size SSWC.
- Inspect all indications of SSWC by exposing the pipe.
- Repair all areas affected by SSWC unless the maximum depth of the SSWC can be shown to be less than 10% of the wall thickness.

- Use an appropriate defect failure assessment technique to calculate the sizes (length-depth combinations) of SSWC that could cause failure at the maximum operating pressure keeping in mind the need to account for the extremely low toughness of the bond line region. See Appendix F and [4].
- Where possible, cut out and pressure test to failure, areas of SSWC to validate the defect failure assessment technique.
- Use the corrosion rate in the bond line, the data on the anomaly-sizing capabilities of the ILI tool used to detect SSWC, and the data on critical sizes that will cause failures in service to establish suitable re-inspection intervals.
- Alternatively, use periodic hydrostatic testing at sufficiently short intervals to eliminate SSWC anomalies before they can grow to a size that would cause failures in service. This can be done via the Fessler-Rapp [5] method or a modified version of it [6].

Consider as an example a pipeline comprised of 16-inch-OD, 0.250-inch wall, API Grade 5LX52 line pipe manufactured with a direct-current-welded ERW seam in 1953 by the Youngtown Sheet and Tube Company. The pipeline was coated over the ditch with coal tar enamel and felt wrap. A material of this type and vintage will likely be susceptible to SSWC, if the pipe is exposed to corrosive conditions. If this pipeline is known to have experienced external corrosion-caused metal loss either because of prior in-service or hydrostatic test failures, or if ILI runs or ECDA measurements have established the existence of significant amounts of external corrosion, the pipeline should be considered at risk of failure from SSWC. An SSWC mitigation plan is needed.

The flowchart for IC + DPS interacting threat identification is presented in Figure 2.



(1) Use S < 0.02 wt% for a critical grooving factor less than 2

Figure 2. Flowchart for EC + DPS Interacting Threat Identification

The flowchart content for the DPS + EC threat interaction identification flowchart is as follows:

- The assessment is limited to lines with ERW or flash welded seam pipe.
- Test 1 is for whether or not the seam is high-frequency welded. If the answer is yes, the user is directed to Test 2. If the answer is no or unknown, the pipe is assumed to be susceptible to weld grooving and the user is directed to Test 3.
- Test 2 addresses whether or not the sulfur content of the high-frequency-welded seam exceeds 0.01% by weight. If the answer is no, the pipeline is considered to have low susceptibility to SSWC. If the answer is yes, the pipe is assumed to be susceptible to weld grooving and the user is directed to Test 3.
- Test 3 asks whether or not the coating is in poor condition. If the answer is no, the user is directed to Test 4. If the answer is yes, the user is directed to Test 5.
- Test 4 asks whether or not ILI or EDCA reveals on-going external corrosion. If the answer is yes, the pipeline should be considered susceptible to SSWC, and a mitigation program is needed. If the answer is no, the user is directed to Test 5.
- Test 5 asks whether or not cathodic protection deficiencies exist. If the answer is no, the pipe has low susceptibility to SSWC. If the answer is yes, the pipeline should be considered susceptible to SSWC, and a mitigation program is needed.

Internal Corrosion and Defective Pipe Seam (IC + DPS) Interacting Threat Identification

IC+DPS was found to be the twentieth leading cause of incidents for interactive threats accounting for 13 incidents. The likelihood of failure from IC+DPS (SSWC), depends on the following factors.

- Type of seam. Low-frequency-welded ERW, direct-current-welded ERW, and flash-welded seams should be considered susceptible to SSWC unless there is evidence to show that the seams in a particular pipeline are not susceptible. High-frequency-welded ERW pipe may also be susceptible, especially if its sulfur content exceeds 0.01% and carbon content exceeds 0.1% by weight or the pipe was manufactured before 1985, but the seam region of high-frequency-welded ERW pipe usually has much higher toughness that the seam regions of the other types of pipe. This latter advantage means that defects in the bond line of a high-frequency-welded pipe will take longer to grow to failure than those of the other types of pipe.
- Corrosiveness of the fluid being transported
- Propensity of corrosive fluids to be trapped in low spots or areas of low flow
- Effectiveness of the cleaning pig and/or inhibitor injection program

A pipeline operator may be able to show that the probability of failure from internal SSWC for a particular pipeline segment is so low that it need not be considered in an integrity management plan. If not however, the existence of any one of the following circumstances would indicate the need to develop a mitigative plan to prevent failures from SSWC.

- The pipeline has sustained internal corrosion
- One or more in-service or hydrostatic test failures from either internal base metal corrosion or internal SSWC have occurred.
- The pipeline profile or flow rate is conducive to corrosive fluids being held up in low spots or areas of low flow.
- The pigging and/or inhibitor program is insufficient to satisfactorily mitigate internal corrosion
- Prior ILI runs to detect metal loss show that significant amounts of internal corrosion-caused metal loss have occurred.
- SSWC has been identified in prior examinations of the interior of the pipeline.
- Linear polarization resistance (LPR) tests of representative seam samples indicates potential susceptibility.

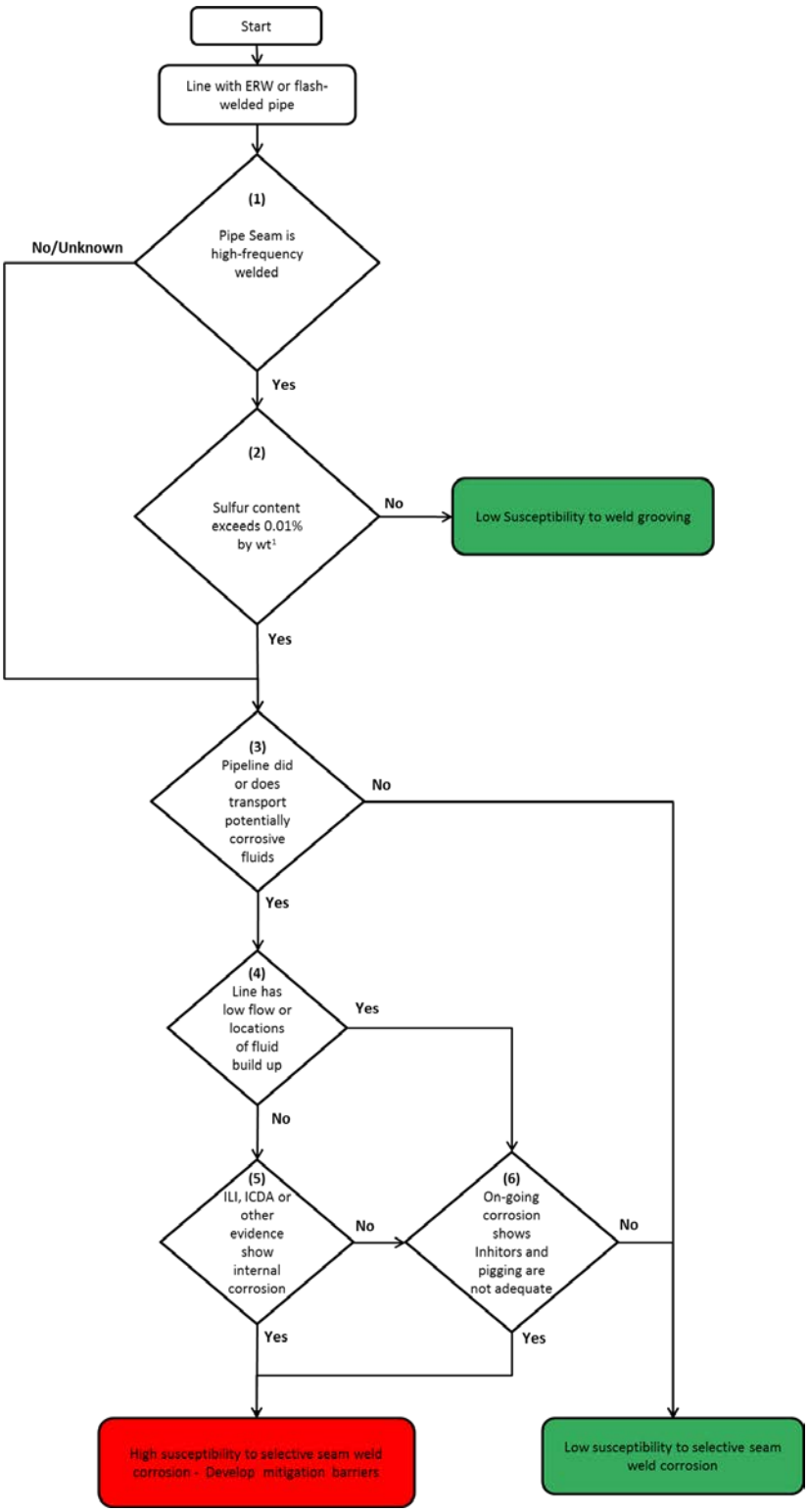
The mitigative plan that should be developed by the operator to prevent failures from internal SSWC should consist of the following elements.

- Review prior ILI runs for detecting internal corrosion-caused metal loss or ICDA data to understand where corrosion has been occurring.
- Run profile and flow analyses to identify areas where fluid hold-up could be occurring.
- Examine the wall thickness at suspect areas.
- Estimate the rate of internal corrosion from prior digs in response to ILI runs.
- If any internal SSWC is identified and the segment containing the SSWC can be removed, use metallographic sectioning to establish the grooving ratio, that is, the ratio of maximum corrosion penetration of the wall thickness in the bond line to the maximum penetration of the surrounding base metal.
- Estimate the rate of SSWC by multiplying the rate of corrosion in the base metal by the grooving ratio.
- Conduct an ILI run using a tool that is capable of identifying and characterizing SSWC anomalies such as a circumferential-field magnetic-flux leakage (CMFL) tool.
- Conduct an ILI run using a longitudinal-field MFL tool as is done normally for metal loss in the body of the pipe.
- Compare the results of both types of inspection to maximize the ability to size SSWC.

- Inspect all indications of SSWC by exposing the pipe.
- Repair all areas shown to be affected by SSWC unless the maximum depth of the SSWC can be shown to be less than 10% of the wall thickness.
- Use an appropriate defect failure assessment technique to calculate the sizes (length-depth combinations) of SSWC that could cause failure at the maximum operating pressure keeping in mind the need to account for the extremely low toughness of the bond line region see Appendix F and Reference [4].
- Where possible, cut out and pressure test to failure, areas of SSWC to validate the defect failure assessment technique.
- Use the corrosion rate in the bond line, the data on the anomaly-sizing capabilities of the ILI tool used to detect SSWC, and the data on critical sizes that will cause failures in service to establish suitable re-inspection intervals.
- Alternatively, use periodic hydrostatic testing at sufficiently short intervals to eliminate SSWC anomalies before they can grow to a size that would cause failures in service.

Consider as an example a pipeline comprised of 16-inch-OD, 0.250-inch wall, API Grade 5LX52 line pipe manufactured with a direct-current-welded ERW seam in 1953 by the Youngtown Sheet and Tube Company. The pipeline transports crude oil that likely contains produced fluids. Almost certainly, a material of this type and vintage will be susceptible to SSWC, if the pipe is exposed to corrosive fluids. If this pipeline is known to have experienced internal corrosion-caused metal loss either because of prior in-service or hydrostatic test failures, or if ILI runs or ICDA measurements have established the existence of significant amounts of internal corrosion, the pipeline should be considered at risk of failure from internal SSWC. An SSWC mitigation plan is needed.

The flowchart for the IC + DPS interacting threat identification is presented in Figure 3.



(1) Use S < 0.02 wt% for a critical grooving factor less than 2

Figure 3. Flowchart for IC + DPS Interacting Threat Identification

The flowchart content for DPS + IC is as follows:

- The assessment is limited to lines with ERW or flash welded seam pipe.
- Test 1 is for whether or not the seam is high-frequency welded. If the answer is yes, the user is directed to Test 2. If the answer is no or unknown, the user is directed to Test 3.
- Test 2 addresses whether or not the sulfur content of the high-frequency-welded seam exceeds 0.01% by weight. If the answer is no, the pipeline is considered to have low susceptibility to SSWC. If the answer is yes, the user is directed to Test 3.
- Test 3 asks whether or not the pipeline did or does transport potentially corrosive fluids. If the answer is no, the pipeline is considered to have low susceptibility to SSWC. If the answer is yes, the user is directed to Test 4.
- Test 4 asks whether or not the pipeline has low flow or locations of fluid build-up. If the answer is no, the user is directed to Test 5. If the answer is yes, the user is directed to Test 6.
- Test 5 asks whether or not ILI, ICDA, or other evidence shows internal metal loss. If the answer is yes, the pipeline should be considered susceptible to SSWC, and a mitigation program is needed. If the answer is no, the user is directed to Test 6.
- Test 6 asks whether or not corrosion is occurring in spite of the use of inhibitors and pigging. If the answer is no, the pipe has low susceptibility to SSWC. If the answer is yes, the pipeline should be considered susceptible to SSWC, and a mitigation program is needed.

External Corrosion and Construction Damage (EC + CD) Interacting Threat Identification

For the purposes of this report coating damage and dents caused by rocks in the backfill are classified as construction damage. Wrinkle bends are also considered construction damage. In contrast if the pipe is hit by equipment during construction and a gouge and/or dent is created, such an incident will be classified as previously damaged pipe. Construction damage (CD) was classified as a stable threat in the Interaction Matrix presented in Table 1. An aggravating factor is required to bring the pipe to failure. External corrosion is the most significant aggravating factor because the pipeline coating is invariably breached by the damage. The EC + CD interaction accounted for a total of 52 incidents and was the third leading cause of incidents arising from interactive threats. CD often results in a coating holiday at the point of contact exposing the pipe to the threat of corrosion. In 32 incidents there was evidence of coating damage, but no initial pipe wall damage, during construction. These latter failures arose solely because of external corrosion at the area of construction-caused coating damage.

PHMSA has identified that the principal causes for coating and pipe damage during the pipeline construction phase are the followings [7]:

- Incorrect backfill preparation – In areas where the ground is rocky and coarse, the backfill material should be screened to remove rocks or the pipe can be covered with a material to protect it from sharp rocks and abrasion. Alternatively, clean fill may be brought in to cover the pipe in areas where the ground is rocky and coarse.
- Incorrect backfill operation – Care must be taken to protect the pipe and coating from sharp rocks and abrasion as the backfill is returned to the trench.
- Incorrect ditch/support preparation – Line resting on rocks.

The EC + CD threat can be mitigated during construction of a new pipeline with good excavation and lowering practices during the construction phase [8]:

- Adequate use of rock shielding, padding and selective backfill.
- Provide adequate boom spacing per ECA requirements.
- Repair any coating damage prior to lowering-in of the pipeline.
- Avoid placing the pipe directly on rocks.

However, for an existing pipeline, susceptibility to the threat of EC + CD depends on a number of factors. The flowchart for EC + CD interacting threat identification is presented in Figure 4.

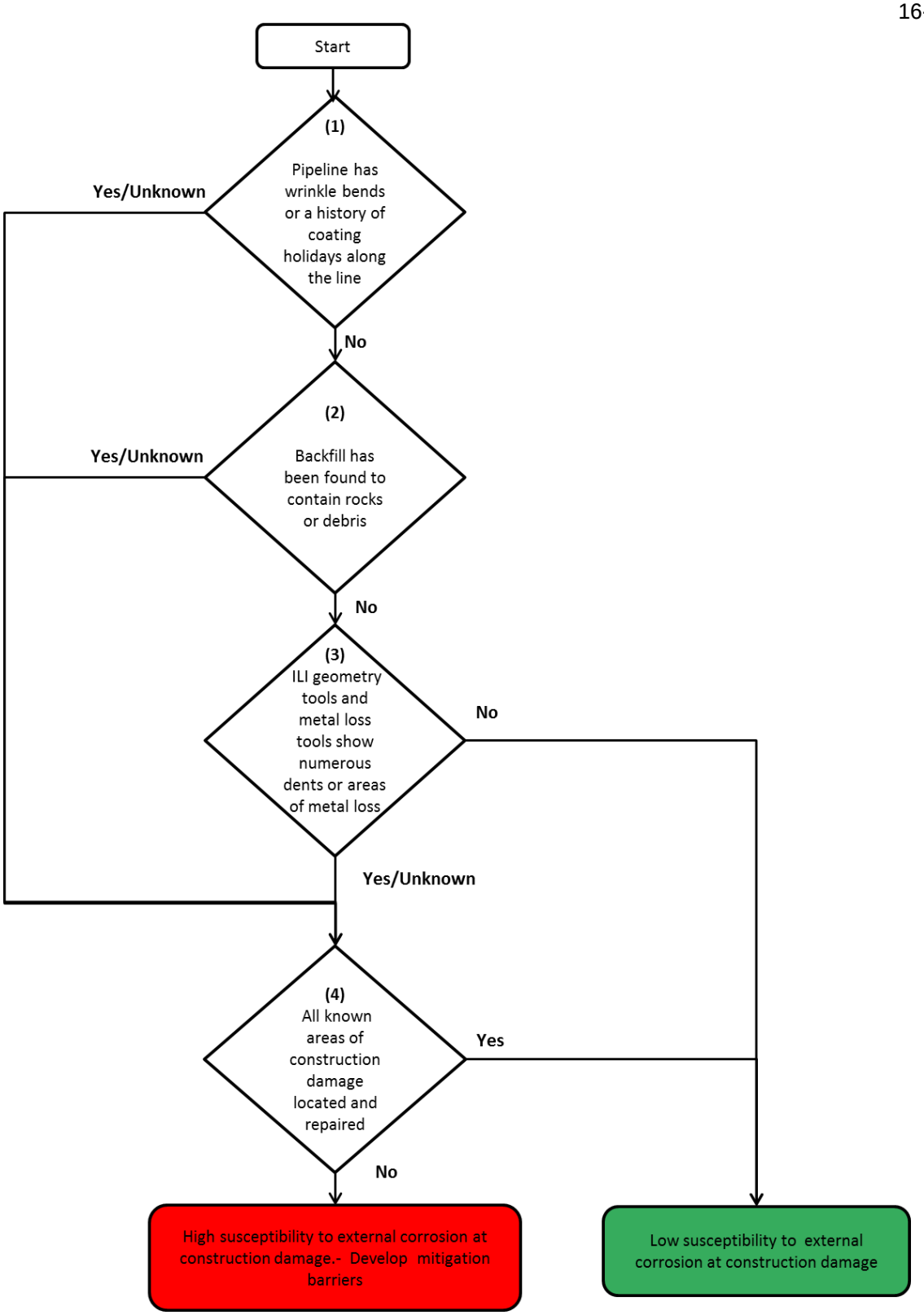


Figure 4. Flowchart for EC + CD Interacting Threat Identification

The EC + CD interacting threat identification process shown in Figure 4 involves the following tests.

- Test 1 asks if the pipe has wrinkle bends and/or has had a history of coating holidays. If the answer is yes or unknown, the line is considered susceptible to construction damage and the user is directed to Test 4. If the answer is no, the user is directed to Test 2.
- Test 2 asks if the backfill has been found to contain rocks and/or debris. If the answer is yes or unknown, the pipeline should be considered susceptible to construction damage and the user is directed to Test 4. If the answer is no, the user is directed to Test 3.
- Test 3 asks if ILI or ECDA show that the pipeline has numerous dents or areas of metal loss. If the answer is yes or unknown, the pipeline should be considered susceptible to construction damage and the user is directed to Test 4. If the answer is no, the pipeline has low susceptibility to EC + CD.
- Test 4 addresses whether or not all known areas of construction damage have been located and repaired. If the answer is no, the pipeline should be considered susceptible to EC + CD, and a mitigation plan is needed. If the answer is yes, the pipeline has low susceptibility to EC + CD.

A mitigation plan for EC + CD is likely to consist of looking for coating faults and/or conducting ILI to find dents and/or metal loss. If the pipeline has been the subject of an ECDA then a valuable snapshot of the coating integrity is available. DCVG and ACVG have been benchmarked as the most accurate above ground techniques for coating condition assessment [9]. It is also required to review any in dig direct inspection reports for any findings of rocks or debris in the lower backfill or evidence of the pipeline resting on rocks.

Assessing the condition of a pipeline that has been identified as highly susceptible to EC + CD requires the combination of different inspection techniques. As mentioned in the previous section, DCVG and ACVG are capable of pinpointing sites with damaged or disbonded coating, but do not provide significant information on the pipe condition. Once a holiday site has been identified via ECDA, it can be directly inspected for denting and/or corrosion pitting. ILI techniques are available for locating and sizing dents and for assessing metal loss.

If coating damage or a rock has been detected, the remediation measures are to re-condition the backfill and/or rehabilitate the coating of the section affected. When pipe damage has been identified, it should be preferably characterized and remediated in situ. If a plain dent (with no gouge or crack) is to be left unrepaired, the fatigue life of the dent from the standpoint of

pressure cycles can be calculated via the dent stress concentration factor approach illustrated in Appendix D.

External Corrosion and Previously Damaged Pipe (EC + PDP) Interacting Threat Identification

The EC + PDP interaction accounted for a total of 15 cases and was the nineteenth leading cause of failure. All cases involved external corrosion happening at sites with unrepaired pipe wall impact damage (denting and/or gouging).

The EC + PDP flowchart is shown in Figure 5.

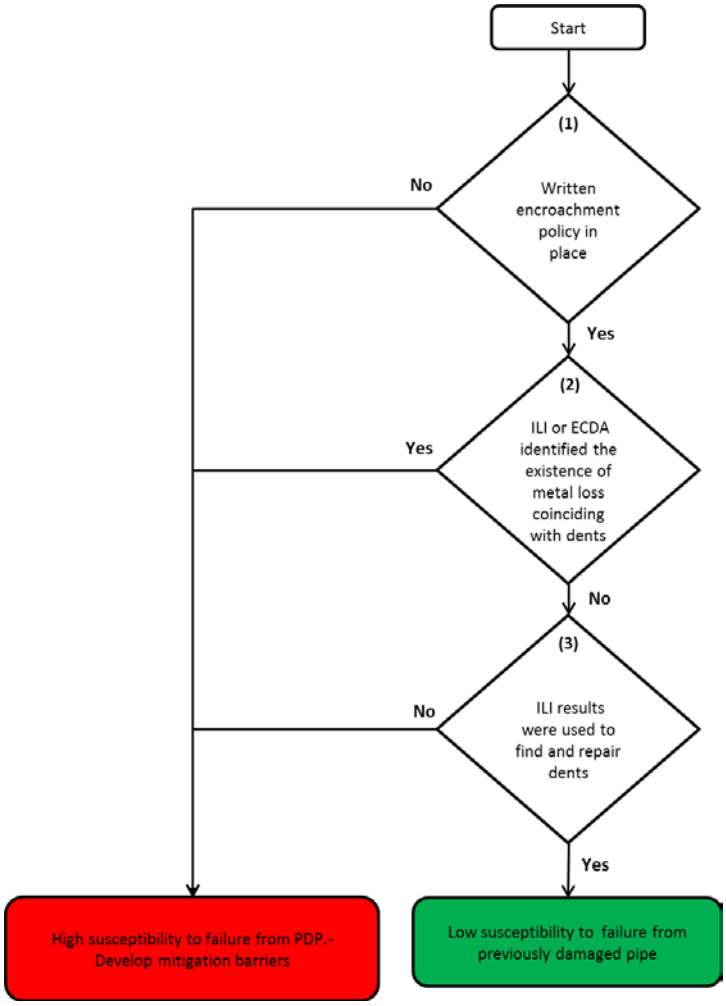


Figure 5. Flowchart for EC + PDP Interacting Threat Identification

The EC + PDP interacting threat identification process shown in Figure 5 involves the following tests.

- Test 1 asks if a written encroachment policy exists for the pipeline. Such a policy should outline the steps and actions the operator takes to prevent unauthorized persons from excavating near the pipeline, and to assure that any necessary excavations are done in a manner that will not cause damage to the pipeline or its coating. If the answer is no, there is no policy, or if the policy that does or did exist is inadequate, the pipeline should be considered susceptible to EC+PDP, and a mitigation plan is needed. If the answer is yes, the user is directed to Test 2.
- Test 2 asks if the ILI or ECDA has located areas of metal loss coinciding with dents. If the answer is yes, the pipeline should be considered susceptible to EC+PDP, and a mitigation plan is needed. If the answer is no, the user is directed to Test 3.
- Test 3 asks if ILI was used to find and repair dents or areas of metal loss. If the answer is no, the pipeline should be considered susceptible to EC+PDP, and a mitigation plan is needed. If the answer is yes, the pipeline has low susceptibility to EC+PDP.

A mitigation plan for EC + PDP is likely to consist of looking for coating faults and/or conducting ILI to find dents and/or metal loss. If the pipeline has been the subject of an ECDA then a valuable snapshot of the coating integrity is available. DCVG and ACVG have been benchmarked as the most accurate above ground techniques for coating condition assessment [9]. It is also required to review any in dig direct inspection reports for any findings of rocks or debris in the lower backfill or evidence of the pipeline resting on rocks.

Assessing the condition of a pipeline that has been identified as highly susceptible to EC + PDP requires the combination of different inspection techniques. As mentioned in the previous section, DCVG and ACVG are capable of pinpointing sites with damaged or disbonded coating, but do not provide significant information on the pipe condition. Once a holiday site has been identified via ECDA, it can be directly inspected for denting and/or corrosion pitting. ILI techniques are available for locating and sizing dents and for assessing metal loss.

If previously damaged pipe is detected, the remediation measures are to excavate and repair all dents with gouges and to rehabilitate the coating of the section affected. When pipe damage has been identified, it should be preferably characterized and remediated in situ. If a plain dent (with no gouge or crack) is to be left unrepaired, the fatigue life of the dent from the standpoint of pressure cycles can be calculated via the dent stress concentration factor approach illustrated in Appendix D.

Lastly, the mitigation of EC+PDP, unlike that of EC+CD which can be a one-time exercise, requires periodic re-assessment because unauthorized encroachment can occur again in spite of continuing vigilance via the encroachment policy.

External Corrosion and Incorrect Operations (EC + IO) Interacting Threat Identification

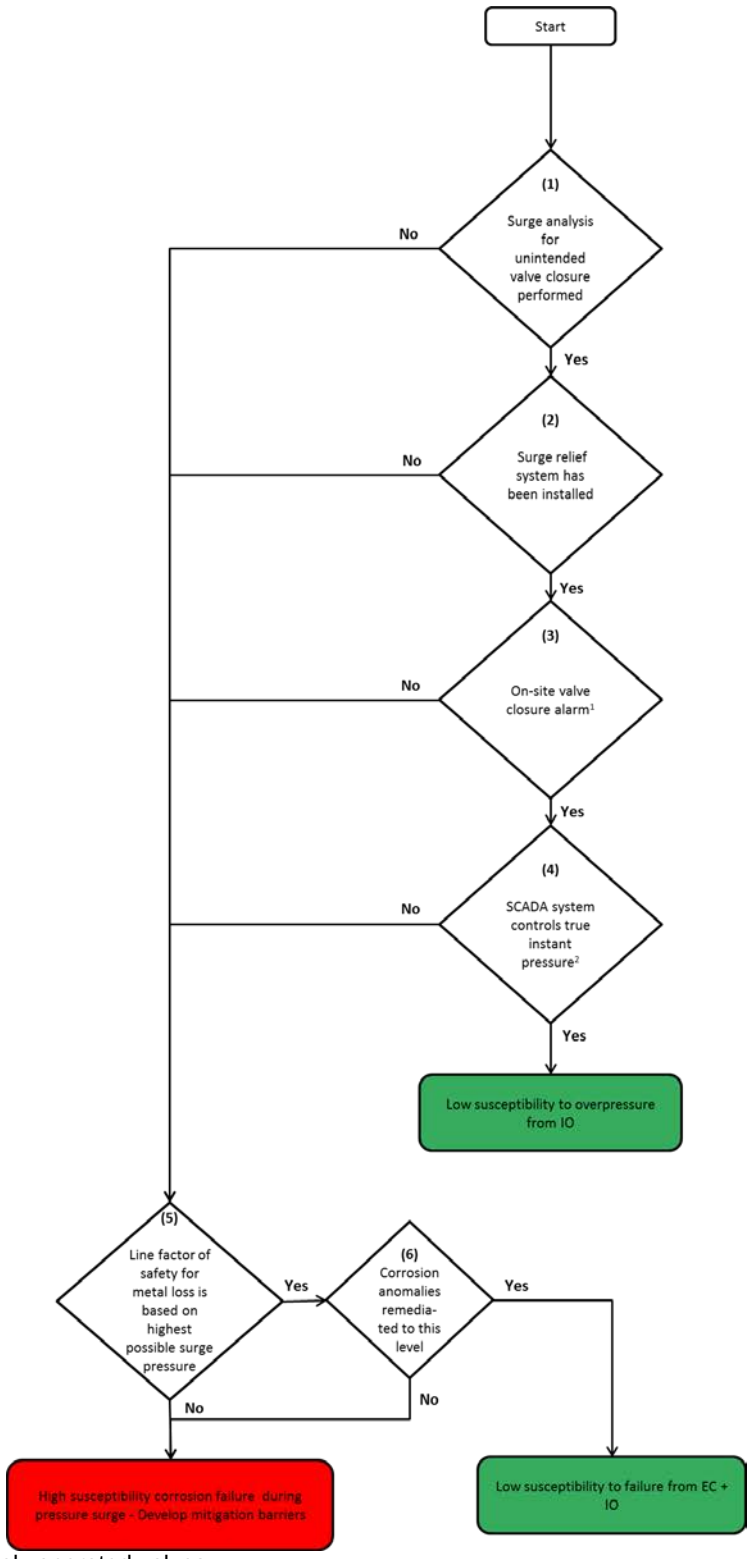
EC + IO interaction accounted for a total of 27 incidents and was the fourteenth leading cause of incidents from interacting threats. Sixteen (15) incidents were caused by unwanted pressurization of a corroded line. Six cases were associated with CP interference or coating damage. Four incidents had a vibration fatigue component. Finally, three cases present miscellaneous maintenance malpractices. The details of the incidents are presented in Appendix B.

The majority of the narratives of EC + IO and IC + IO report a failure occurring from over-pressurization. Whereas the corroded pipe would have survived for some time at the normal operating pressure, the over-pressure in the pipeline caused the strength of the remaining wall of thickness of the corroded pipe to be exceeded. The over-pressurizations were the result of lack of control from the operations personnel during a transient operation. From the narratives of the failure incidents, the system considered is natural gas or hazardous liquids pipeline system in transient operation - the failure occurs during the operation of pressure control equipment.

Over-pressurization is characteristic of these types of failures and is attributed to “operations personnel not following company procedures”. The narratives do not give specifics of the factors influencing these human errors, hence Kiefner decided to adopt the factors listed in some over-pressure prevention guidelines [10, 11, 12]:

- Lack of adequate valve closure control
- Lack of pressure monitoring
- Lack of surge relief system or lack of surge pressure analysis

These three factors were integrated in the flowchart shown in Figure 6. The diagram presents two sections: a first one assessing the susceptibility for over-pressurization from human error, followed by a section checking for evidence of corrosion pitting.



(1) Only for remotely operated valves
(2) Some SCADA systems show a pressure trend with values sampled at a fixed interval

Figure 6. Flowchart for EC + IO Interacting Threat Identification

The flowchart content for EC + IO is as follows:

- Test 1 is for whether or not surge analysis has been performed. If the answer is yes, the user is directed to Test 2. If the answer is no, the line is considered susceptible to overpressure and the user is directed to Test 5.
- Test 2 asks whether or not a surge relief system has been installed. If the answer is yes, the user is directed to Test 3. If the answer is no, the user is directed to Test 5.
- Test 3 asks whether or not an on-site valve closure alarm exists for remotely operated valves, since many valve operation sequences are skewed by false valve closure assumption. If the answer is yes, the user is directed to Test 4. If the answer is no, the user is directed to Test 5.
- Test 4 asks whether or not the SCADA system controls true instant pressure. If the answer is yes, the risk of failure from EC + IO is low. If the answer is no, the user is directed to Test 5.
- Test 5 asks whether or not the pipeline's factor of safety for metal loss is based on highest possible surge pressure. If the answer is no, the pipeline should be considered susceptible to EC + IO, and a mitigation program is needed. If the answer is yes, the user is directed to Test 6.
- Test 6 asks whether or not corrosion anomalies are remediated to the maximum surge-determined level of pressure. If the answer is yes, the pipe has low susceptibility to EC + IO. If the answer is no, the pipeline should be considered susceptible to EC + IO, and a mitigation program is needed.

A pressure relief system is the main mitigative barrier for this type of failure, since the critical path to the loss of containment requires an unintended overpressure of the pipeline. Alternatively, the operator could calculate the highest possible surge pressure that could occur, set a factor of safety on that level, and remediate metal loss to the factor of safety level. This latter remedy could be very expensive because it would likely require excavation of many more corrosion anomalies after an ILI run, and ILI runs might have to be conducted at shorter return intervals.

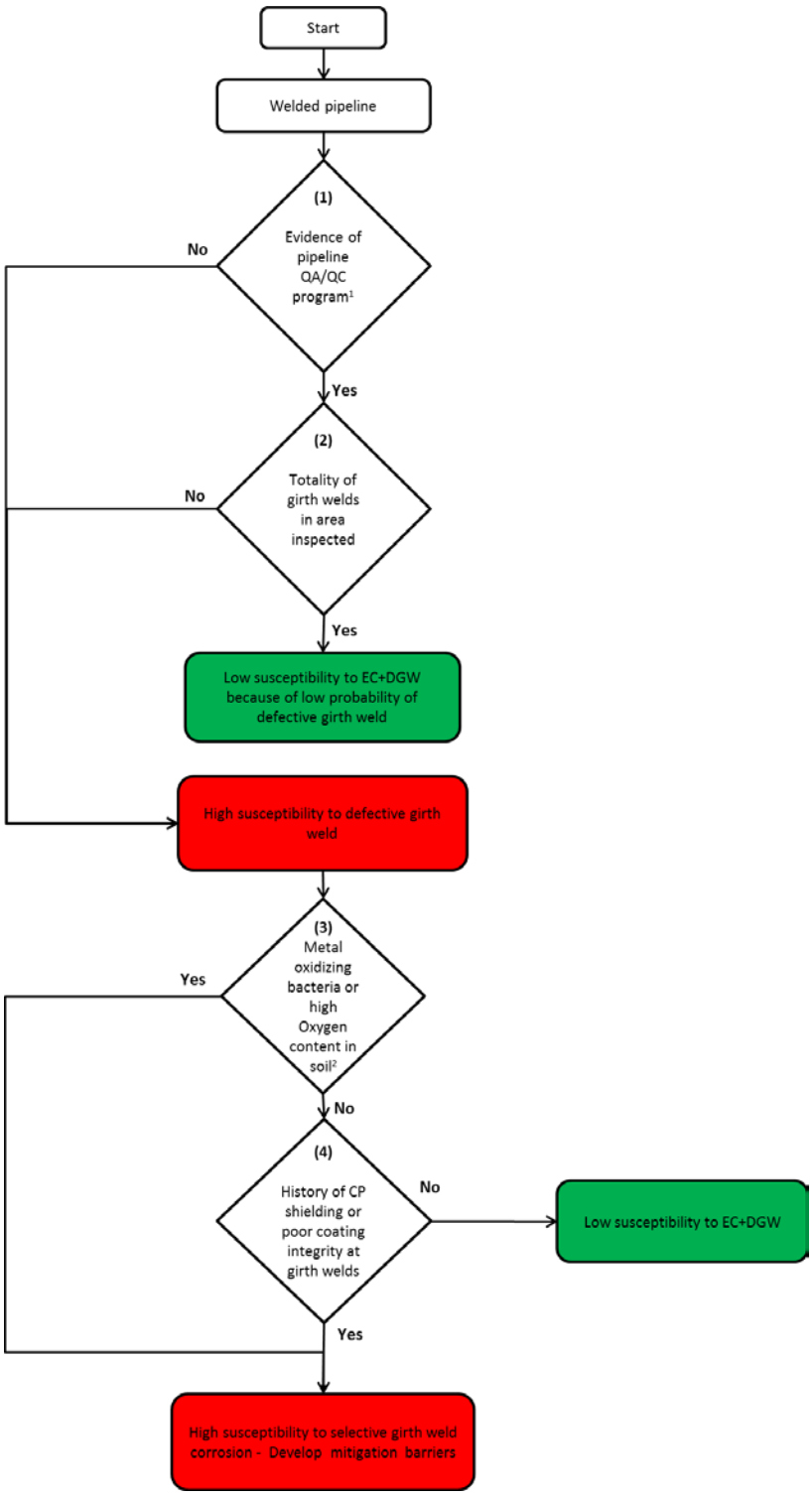
External Corrosion and Defective Girth Weld (EC + DGW) and Internal Corrosion and Defective Girth Weld (IC + DGW) Interacting Threat Identification

EC + DGW and IC + DGW were, respectively, the twenty-third and twenty-first most frequent causes of incidents from interacting threats. As nearly as one can tell from the reportable incidents, most, if not all, occurred as leaks rather than ruptures. This is significant since it

probably means that neither circumferential nor axial stress played much of a role in the occurrences.

The EC/IC + DGW narrative is very simple; preferential corrosion occurs over a girth weld defect, originally introduced during the pipeline's construction that was undetected by the QA/QC program. The corrosion can cause a leak at a weld defect which, by itself, might not otherwise have caused any problem. The existence of the defect facilitates the corrosion penetrating the wall thickness.

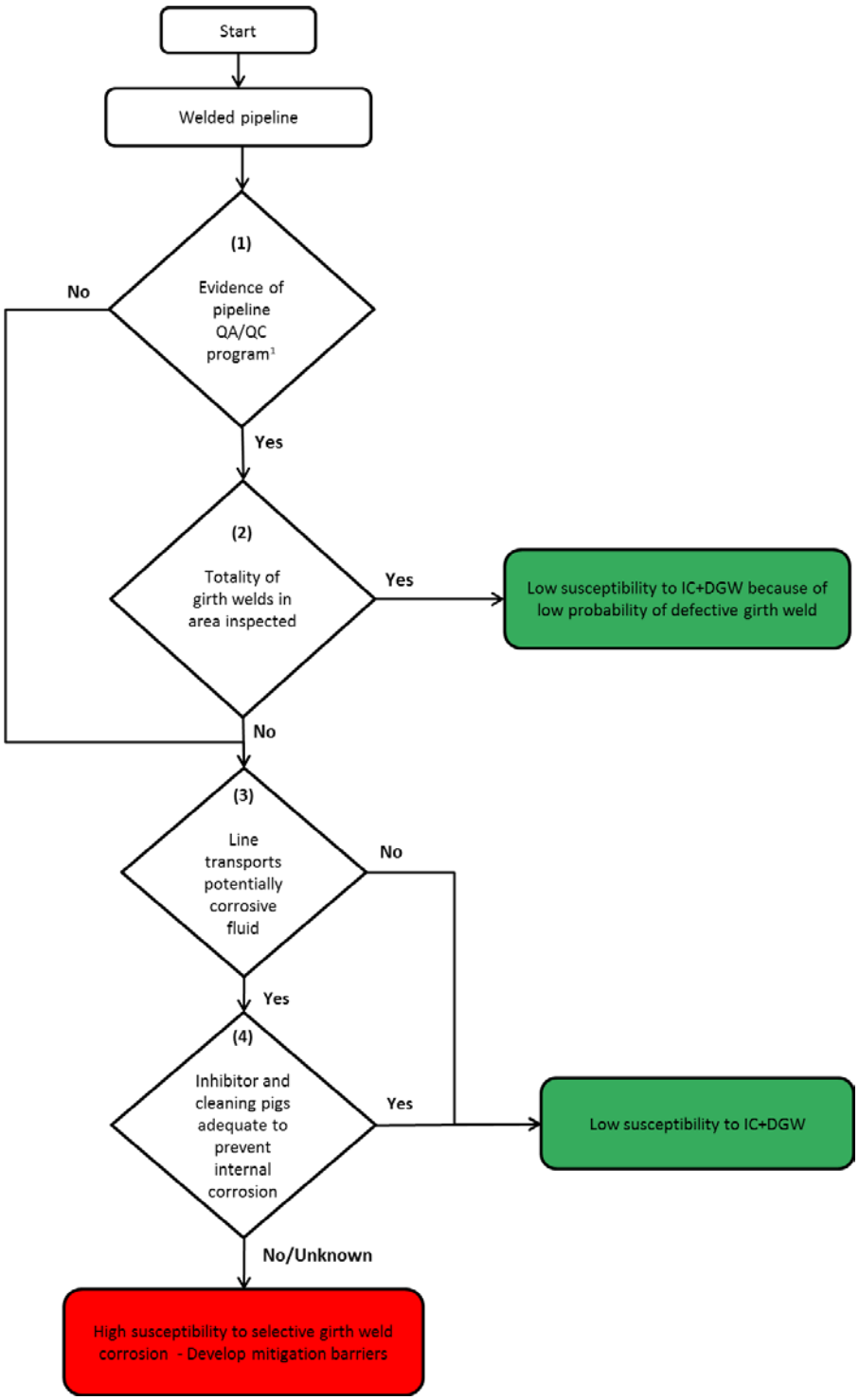
The flowcharts for EC + DGW and IC + DGW interacting threat identification are presented in Figure 7 and Figure 8 respectively. Figure 7, the flowchart for EC + DGW checks for evidence of a QA/QC program during the construction phase (Test 1) and whether or not the totality of the girth welds were inspected (Test 2). If the welding procedure specifications were developed and properly qualified by tests of procedures and welders and if close to 100% of the welds were radiographed, then the probability of a weld being defective is low. As such the EC+DGW threat can be ignored in the integrity management plan. If the answers to either Test 1 or Test 2 was no, the flowchart directs the user to whether or not corrosive conditions could be present at the location of a girth weld defect. Test 3 involves checking for the likelihood of MIC corrosion, and Test 4 checks for evidence of CP shielding or poor coating at girth welds. If either of these corrosive conditions are known to present or the quality of the coating or the level of cathodic protection of the girth welds is questionable, a mitigation plan for EC + DGW is needed. If neither corrosive conditions nor coating nor CP deficiencies exist, the EC + DGW threat can be ignored in the integrity management plan.



(1) Qualifications of welders and welding procedures and NDE of welds
(2) Coarse, well aggregated and dry soils without vegetation have the highest Oxygen content

Figure 7. Flowchart for EC + DGW Interacting Threat Identification

Figure 8, the flowchart for IC + DGW checks for evidence of a QA/QC program during the construction phase (Test 1) and whether or not the totality of the girth welds was inspected (Test 2). If the welding procedure specifications were developed and properly qualified by tests of procedures and welders and if close to 100% of the welds were radiographed, then the probability of a weld being defective is low. As such the IC + DGW threat can be ignored in the integrity management plan. If the answers to either Test 1 or Test 2 was no, the flowchart directs the user to whether or not corrosive conditions could be present at the location of a girth weld defect. Test 3 involves checking for the corrosivity of the fluid being transported, and Test 4 checks for whether or not the inhibitor and cleaning pig program is capable of mitigating internal corrosion. If the pipeline does not transport a potentially corrosive fluid or transports a potentially corrosive fluid but the inhibitor and cleaning program is adequate to prevent corrosion, then the IC + DGW threat can be ignored in the integrity management plan. If the pipeline transports a potentially corrosive fluid and the effectiveness of the inhibitor and cleaning pig program is not adequate or is of questionable adequacy, a mitigation plan for IC + DGW is needed.



(1) Qualifications of welders and welding procedures and NDE of welds

Figure 8. Flowchart for IC + DGW Interacting Threat Identification

The likelihood of EC + DGW is influenced by the coating integrity, cathodic protection shielding and the soil environment. Soil characterization requires soil sampling and chemical analysis. Pipe external coating type is reported in the pipeline feature list; it should be verified whenever in-dig inspections are performed in the line. Pipe coating deterioration and cathodic protection effectiveness are within the scope of any External Corrosion Direct Assessment (ECDA) and are commonly assessed using close interval survey (CIS), direct current voltage gradient (DCVG), alternate current voltage gradient (ACVG) and pipeline current mapping (PCM) techniques.

Mitigation of EC/IC+DGW is largely dependent on finding metal loss anomalies in the girth welds via ILI before they become large enough to fail in service. The girth welds of a section of a pipeline can be inspected with UT, MFL or EMAT tools and locations of anomalies can be examined and repaired if necessary during ITD inspections.

If an ILI program is not feasible, hydrostatic testing can be used to mitigate the EC/IC+DGW threat. However, this is likely to be an expensive and inefficient response because the failure mode of these types of anomalies is almost always that of a leak. It is well known that small pit-like defects, even if very deep, often escape detection during hydrostatic testing. A better approach might be to use ECDA to locate coating anomalies to check for EC at girth welds or examine girth welds at low spots in the pipeline to assess for IC at girth welds.

Defective Pipe Seam and Incorrect Operations (DPS + IO) Interacting Threat Identification

The DPS + IO threat exists when a crack-like defect is introduced during the manufacture of a seam weld that can later propagate via pressure-cycle-induced fatigue. Failure on the part of the operator to properly account for the effects of pressure-cycle-induced fatigue on potential seam defects constitutes incorrect operation.

DPS + IO constitutes the twenty-second leading cause of incidents involving interacting threats. DPS + IO interactions accounted for a total of 11 incidents, all occurring in liquid pipelines, at least 8 of which pretty clearly were caused by pressure-cycle-induced fatigue cracking which initiated at seam weld defects. No such incidents were encountered in gas pipelines, and that probably reflects the fact that gas pipelines tend to be subjected to much less aggressive pressure cycling than some liquid pipelines. However, gas operators, from time to time, should at least evaluate the levels of exposure of their pipelines to pressure-cycle-induced fatigue and classify seam defects as a stable threat if and only if they can show that there is a very low probability of failure from pressure-cycle-induced fatigue within the useful life of the pipeline.

The flowchart for DPS + IO interacting threat identification is presented in Figure 9. The analysis suggested in the flowchart is intended primarily for longitudinal seam defects. However, any significant longitudinally-oriented defect could become enlarged via pressure-

cycle-induced fatigue. This could include longitudinally-oriented pipe body manufacturing defects, SCC, or a gouge and/or dent.

The first test in Figure 9 asks whether or not the pipeline has been subjected to a hydrostatic test to at least 1.25 times its maximum operating pressure (MOP for a liquid pipeline) or its maximum allowable operating pressure (MAOP for a gas pipeline). If the answer is no, the pipeline is considered susceptible to failure from pressure-cycle-induced fatigue, and a mitigation program is needed. If the answer is yes, the user is directed to the second test.

The second test asks whether or not a pressure-cycle analysis has been conducted. Techniques for conducting such analyses are presented in Appendix D. If the answer is no, the pipeline is considered susceptible to failure from pressure-cycle-induced fatigue, and a mitigation program is needed. If the answer is yes, the user is directed to the third test.

The third test asks whether or not the analysis shows that a hypothetical defect could grow to failure within the useful life of the pipeline. If the answer is yes, the pipeline is considered susceptible to failure from pressure-cycle-induced fatigue, and a mitigation program is needed. If the answer is no, longitudinal defects in the pipeline can be considered stable.

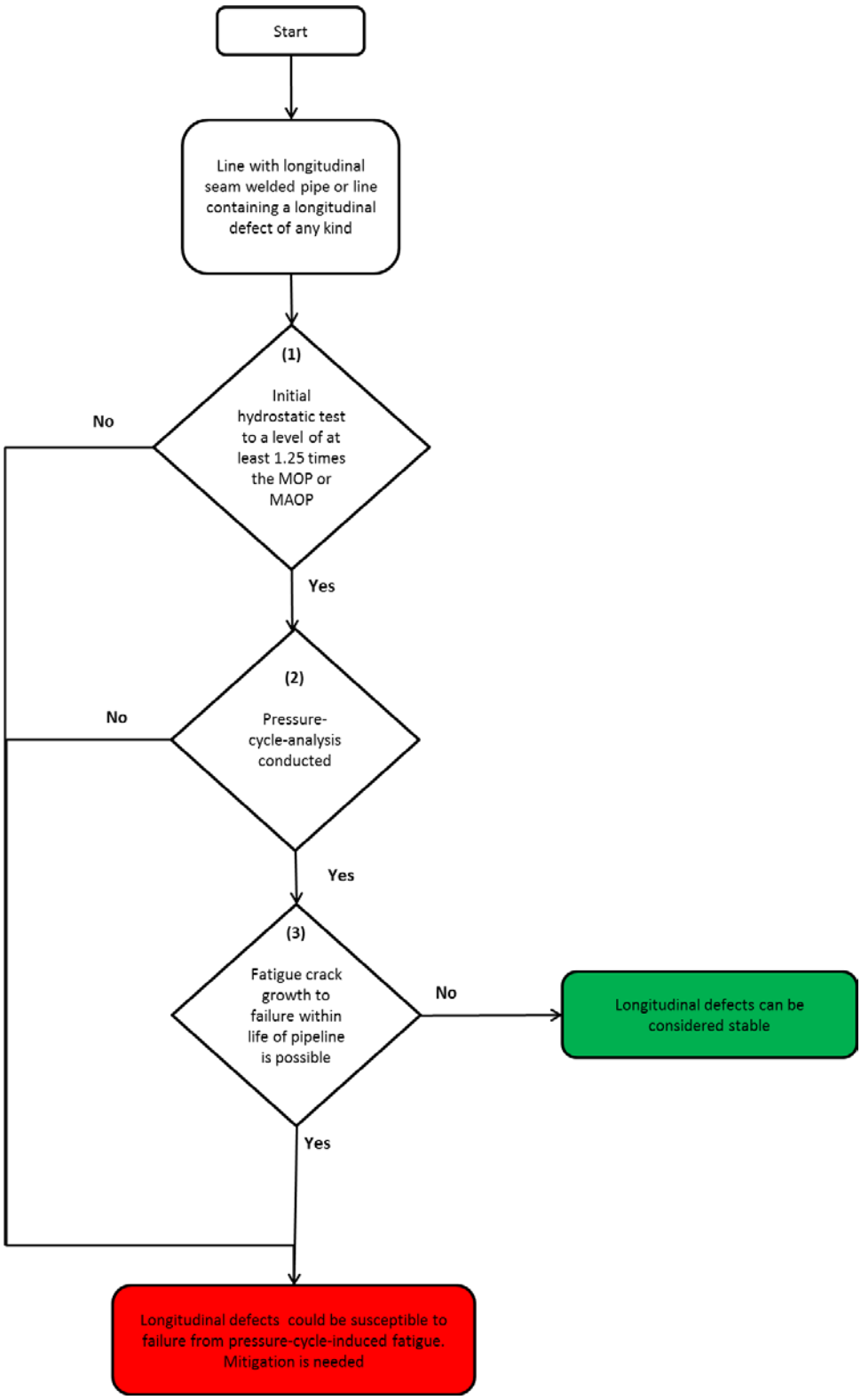


Figure 9. Flowchart for DPS + IO Interacting Threat Identification

The essential requirements for managing the DPS+IO threat are a means to establish the worst case hypothetical longitudinal defect in the pipeline, an accurate description of the pressure cycle spectrum that represents the operation of the pipeline, and a means to periodically re-validate the integrity of the pipeline. The worst case defects can be established by means of a hydrostatic test or an in-line inspection using a crack-detection technology that has been proven reliable at finding and accurately characterizing the sizes of cracks with sizes above the detection threshold size. The times to failure of identified cracks can then be predicted by applying analytical techniques described in Appendix D. Mitigation of such cracks then consists of periodically retesting the pipeline (periodic hydrostatic testing) or periodically re-running ILI crack-detection tools to allow removal or repair of any growing cracks before they can grow large enough to fail in service.

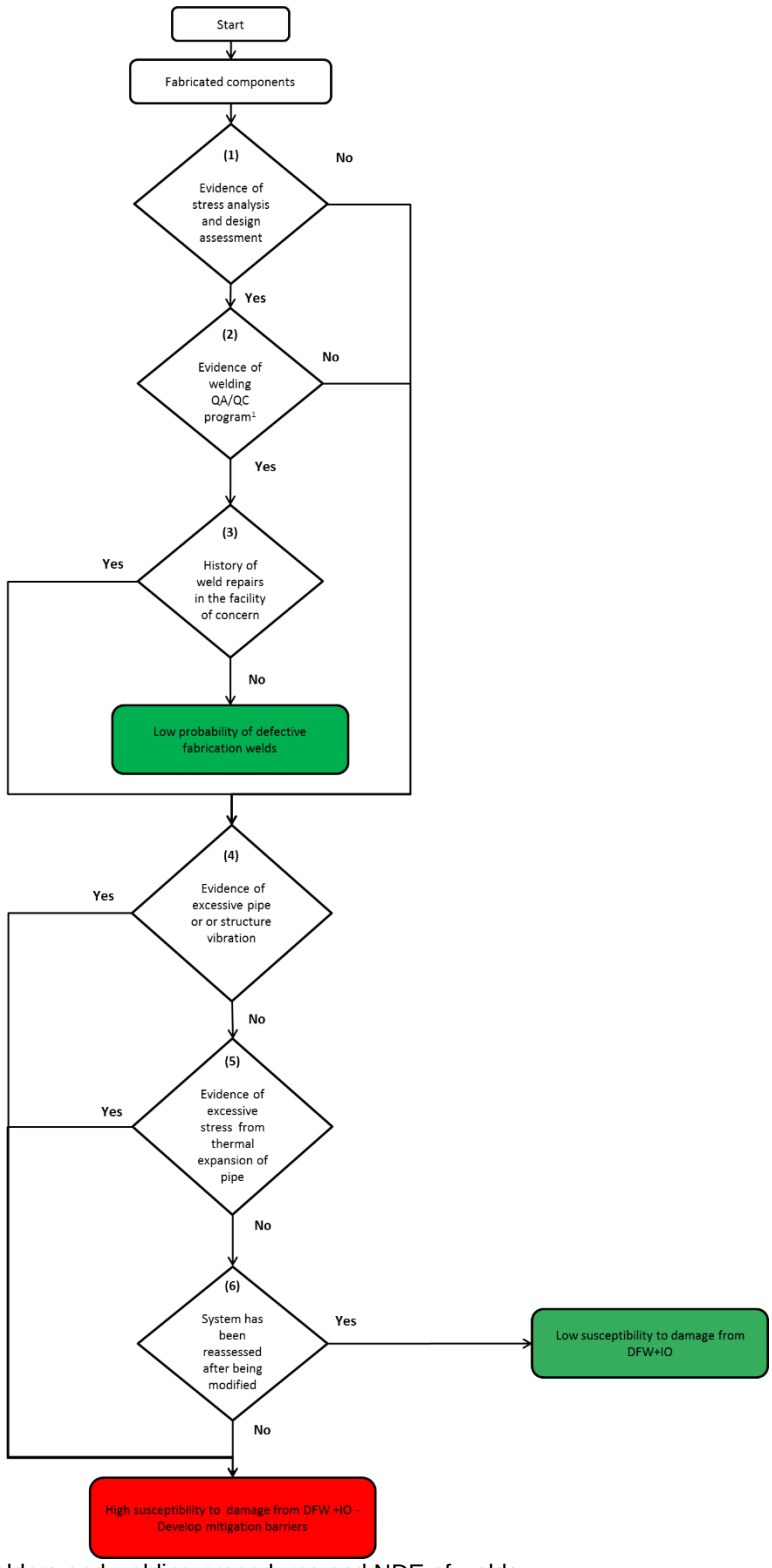
Defective Fabrication Seam and Incorrect Operations (DFW + IO) Interacting Threat Identification

DFW + IO interactions accounted for 18 incidents, with the vast majority reporting excessive vibration initiating a crack in a weld defect. DFW+IO was the sixteenth most frequent cause of incidents involving interacting threats.

DFW + IO occurs when a crack-like defect is introduced during the fabrication of a component and later propagates under excessive vibration of the component. Pulsation bottles, slug catchers, and heat exchangers in gas compressor stations; meter provers and manifolds in liquid pump stations; and pig traps and fabricated branch connections in pipelines are typical fabricated components. Mechanical vibration or pressure pulsations from inadequate design can lead to failure. Inadequate design or the failure to implement measures to prevent the vibration or movement of the pipe or components would be considered a form of incorrect operation.

A common cause of excessive vibration is the high variability of some process that provokes pressure variations, and lack of pipe support exacerbates this problem. Localized vibration can also be caused by operating machinery such as pumps and compressors or by bad design. A vortex inducing component, such as a gate valve, can lead to excessive vibration of the downstream segment.

The flowchart for DFW + IO interacting threat identification is presented in Figure 10.



(1) Qualifications of welders and welding procedures and NDE of welds

Figure 10. Flowchart for DFW + IO Interacting Threat Identification

There are six tests in Figure 10 to categorize the DFW + IO threat interaction. Test 1 asks whether or not there is evidence that the component has been subjected to stress analysis and that it has been adequately designed. If the answer is yes, the user is directed to Test 2. If the answer is no, the user is directed to Test 4. Test 2 addresses evidence of a QA/QC program during the fabrication phase. If there is evidence of such a program (a "yes" answer), the user is directed to Test 3. If no evidence exists, the user is directed to Test 4. Test 3 addresses the history of weld repairs in the fabrication welds. If there has been no history of weld repairs it is assumed that the fabrication welds are adequate, that the susceptibility to defective fabrication welds is low and that no special mitigation of the DFW+IO threat is needed. If the answer to Test 3 is yes, the user is directed to Test 4.

Test 4 asks whether or not there is evidence of excessive pipe or structure vibration. If there is evidence of vibration, the component should be considered susceptible to the DFW + IO threat interaction. If there is no evidence of vibration, the user is directed to Test 5.

Test 5 asks whether or not there is evidence of excessive stress from thermal expansion. If there is evidence of stress from thermal expansion, the component should be considered susceptible to the DFW + IO threat interaction. If there is no evidence of stress from thermal expansion, the user is directed to Test 6.

Test 6 asks whether or not the system has been re-assessed after any modification of its configuration. If there has been no re-assessment, the component should be considered susceptible to the DFW + IO threat interaction. If there has been a re-assessment the threat of DFW + IO is considered negligible.

There are a number of mitigative steps that can be taken if the threat of DFW+IO is determined to exist. If the maintenance group has a maintenance ticketing or log system, it should be reviewed for evidence of lack of support and excessive line vibration. The alignment sheets, as-built drawings and PIDs should be reviewed for gate valves or components that produce kernel vortex into the flow immediately upstream of the feature being assessed. Line modifications can also be identified in the drawings. Pressure and temperature history should be exported from the SCADA system and reviewed to determine the variability of the process. The objective is to minimize vibrations and stresses from pressure or thermal transients. Operators may find useful information for stress analysis and design by consulting Appendices H and I herein.

Fabrication welds are generally inspected from the outside; it is generally difficult to navigate and position internal tools inside those systems. If the external surface can be accessed, then the fabrication weld can be inspected with different UT and MFL techniques (such as phased array ultrasonic testing, or PAUT) for discontinuities. PAUT is particularly adept at detecting and

characterizing weld flaws. After repairs are made it may be necessary to subject the component to a stress relief heat treatment.

If a component can be removed from service it may be desirable to subject it to a hydrostatic testing to assess its integrity. Such a test would usually be conducted at a minimum pressure level of 1.5 times the required MOP.

Malfunctioning Pressure Control or Relief Equipment and Incorrect Operations (MCRE + IO) Interacting Threat Identification

MCRE+IO was the twelfth most frequent cause of incidents from interactive threats. The MCRE + IO interaction accounted for a total of 29 incidents. Twelve incidents were caused by a valve malfunction followed by the operator's failure to notice the anomalous condition or failure to shutdown/isolate the section affected. Eleven incidents were caused by an incorrect transient operation which resulted in a valve being in wrong position followed by a malfunction of the emergency shut-down (ESD) valve or relief equipment (generally a relief valve not seating). The narrative of this type of failure presents a sequence of events where a valve fails to operate adequately, followed by a communication error provoking the overflow of a vessel or over-pressurization of a segment of the line. The system considered is a pipeline during transient operation.

Some narratives mention debris or corrosion product in the valve seat, but the cause for the valve malfunctioning is often inconclusive. Hence, Kiefner decided to consider all possible causes of valve closure malfunction, which are the following [13]:

- Corrosion Product trapped inside the valve
- Debris or solid particles trapped inside the valve
- Loss of power to activate a remotely operated valve
- Loss of communication with a remotely operated valve (i. e. signal failure)
- Inadequate control of the closed state of a remotely operated valve closure

The factors affecting the incorrect flowrate increase are:

- Lack of valve closure confirmation between the on-site personnel and the personnel in the control room.
- Restricted access to a manual operated valve hinders its operation.
- The operation involves a complicated valve operation sequence.

The flowchart for MCRE + IO interacting threat identification is presented in Figure 11. Three different sections were required to cover the two variants of this type of interaction. The first

section tests for debris entrapment susceptibility and defective valve/relief control equipment. The second section pertains to remote valve operations and checks for loss of communication issues. The third section tests for incorrect operations that might lead to an anomalous increase in the flowrate.

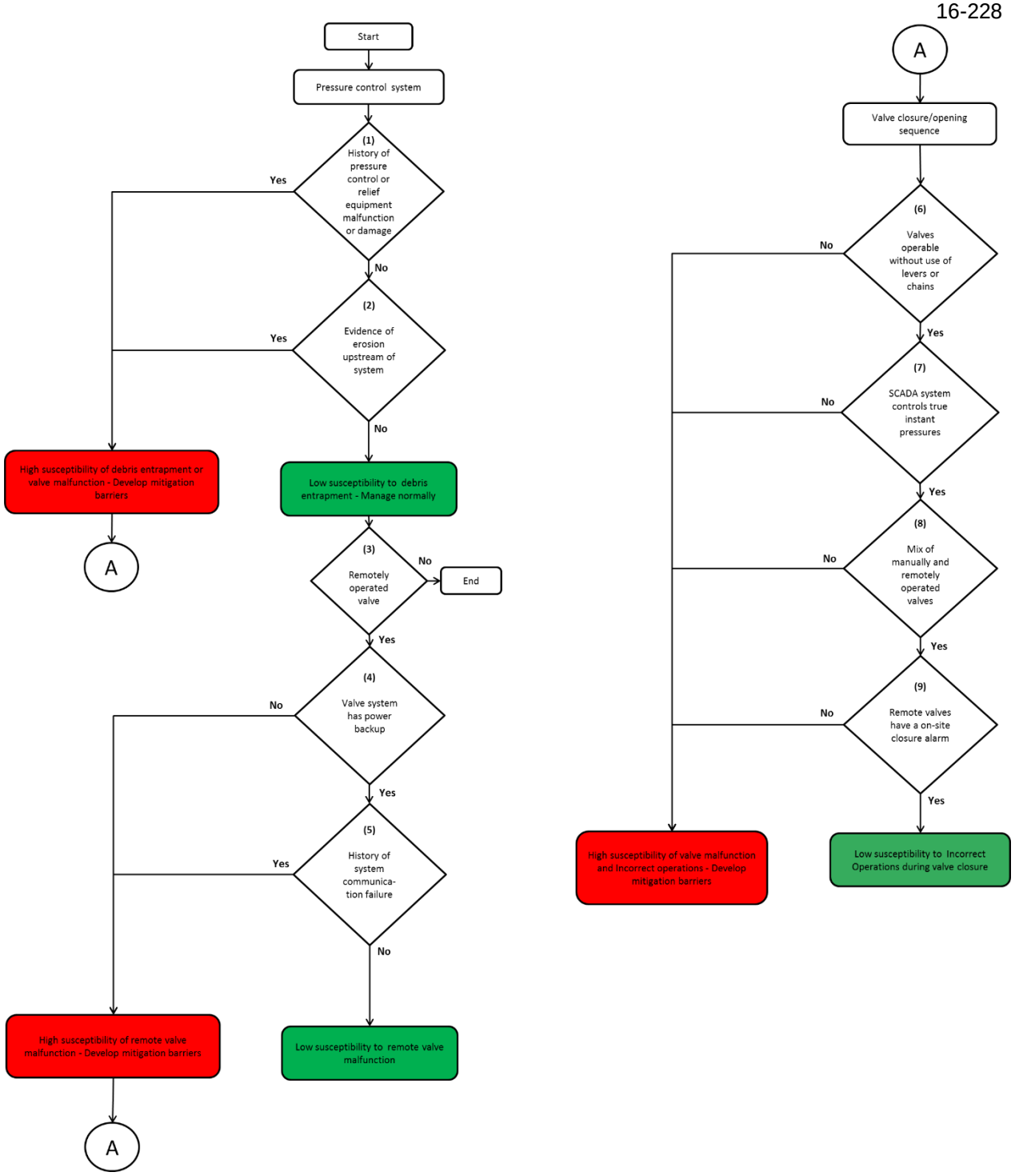


Figure 11. Flowchart for MCRE + IO Interacting Threat Identification

The MCRE + IO interacting threat identification assessment requires reviewing any history of pressure control or relief equipment failure. In addition, the process requires assessing the possibility of erosion happening upstream of the valve. If the line has been assessed for that particular threat in the past, then the assessment report should be reviewed. Otherwise, it is

recommended to calculate the erosional velocity limit according to API 14E and compare to the fluid velocity of the line. It would be also convenient to review any past fluid analysis of the line for solid particle content that might deposit at the valve.

The interacting threat identification assessment has a section dedicated to remote valves. In order to evaluate the fail-safe measures, it is required to review the instrumentation and controls of the remote valves. The valve specification and the associated Piping and Instrumentation Diagram (PIDs) might have sufficient detail, but an interview with the personnel at the control room should suffice to get the pieces of information required (fail-safe valve position, power backup and communication system adequacy).

The IO threat occurs during a transient operation with a sequence of valve closure/opening. The assessment requires identifying the valves operated; the valve operation sequence should be detailed in the operation procedure and the valve details should be reported in the Pipeline Feature List (PFL).

There is no effective inspection technique to detect debris or corrosion products in the valve seats. Hence, the valve condition can only be assessed during its maintenance; any evidence of corrosion product or debris entrapment should be reported. In addition, all valves should be tested periodically for complete opening and closure.

Mitigative barriers to minimize the MCRE+IO threat are as follows. A back-up power supply is an essential mitigative measure to ensure the operation of remotely operated valves. In addition, some pipeline operators have installed backup communications systems in order to prevent loss of communication with remotely operated valves.

Malfunctioning Pressure Control or Relief Equipment and Cold Weather (MCRE + CW) Interacting Threat Identification

The threat of MCRE+CW was the most frequent cause of incidents involving interacting threats. This finding is consistent with a separate study [78] that observed frozen components to be the second most-frequent cause of cold-weather incidents in natural gas and hazardous liquid transmission pipelines (after frost heave). The MCRE + CW interaction accounted for 60 incidents. The interaction has a high incident rate in both hazardous liquid and gas transmission pipelines, but low pressure gas transmission lines and gas gathering lines are more susceptible because of the propensity for water or water vapor to be present. The failure can be caused by frozen water inside a valve[9], but in gas pipelines condensation of water can occur when the pipeline is operating below the dew point of the mixture. This is more apt to happen when a

[9] Ten of the incidents in HL lines were classified as MCRE + CW + IO, because incorrect operation or maintenance facilitated water or debris entrapment inside the valve; that narrative is covered in the IO + CW assessment.

pressure drop occurs at a regulator. Twenty incidents in NG lines report a frozen regulator malfunction.

The flowchart for MCRE + CW is presented in Figure 12. The first section of the chart is intended to establish whether or not there has been a history of control and relief equipment malfunction and whether or not there has been evidence of ice formation in the past. The second section is exclusively for low pressure gas transmission lines and gathering lines or for above-ground pipelines or components in liquid service. This section consists of four logical tests. Three of the tests address the likelihood that liquid water can be present and one test assesses whether or not the pressure regulators in a gas system are adequate to avoid water dropout at cold temperatures.

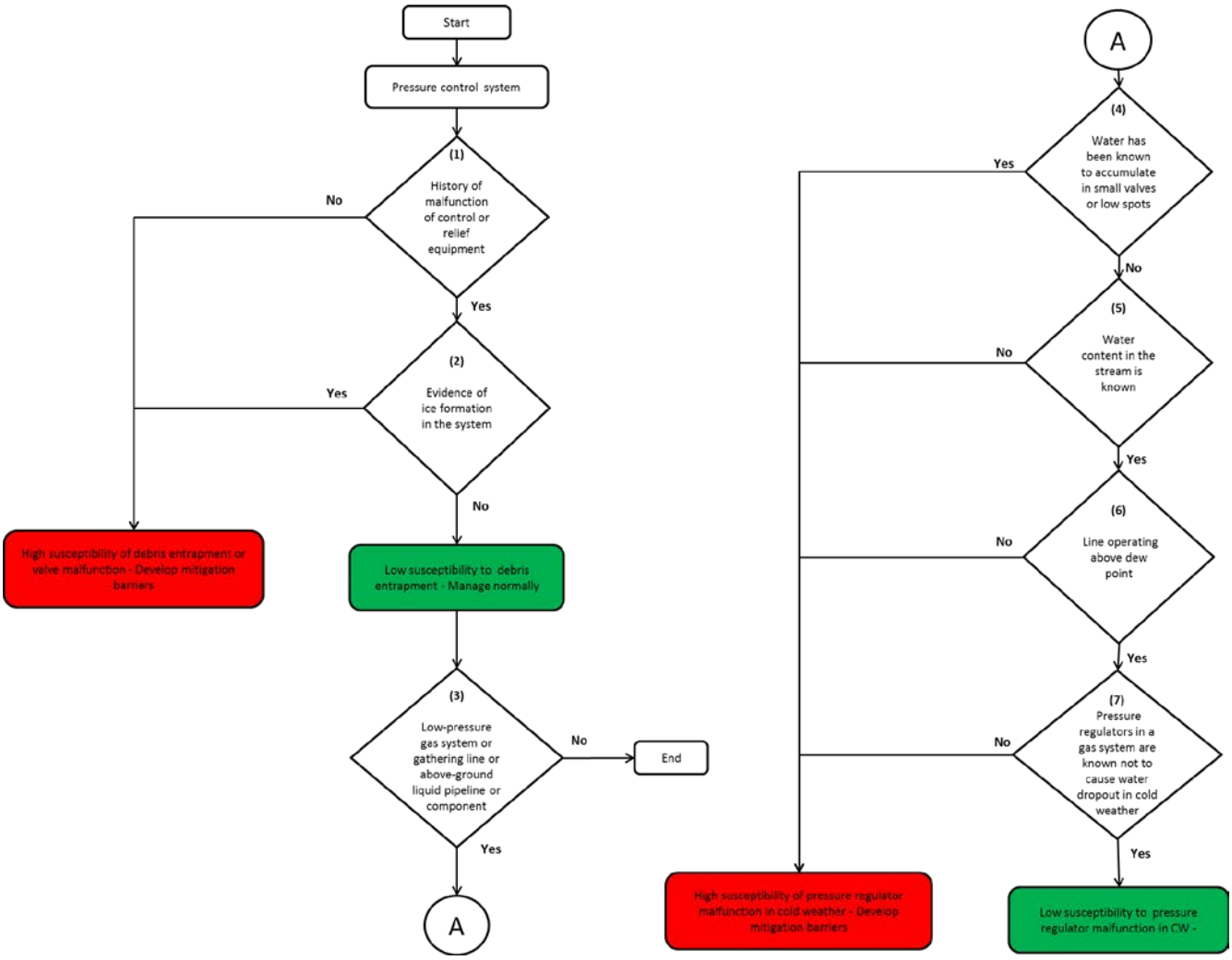


Figure 12. Flowchart for MCRE + CW Interacting Threat Identification

Past operating records may be useful in determining whether or not water has been observed in low spots or within valve bodies. A fluid chemical analysis report can be used to determine the water content and dew point of gas. A temperature log can be exported from the SCADA system in order to check if the line operates below dew point. Finally, the pressure regulators need to be reviewed for low temperature service. The PFL can provide the model type and the specifications can be reviewed to assess the regulator adequacy.

Mitigative barriers that can be considered are as follows. Heat tracing of pipes can help in preventing liquid condensation and/or ice formation. However, these can be a costly. Piping arrangements should allow for the ability to drain water from low spots, and provisions should be made for draining water from small valves ahead of cold weather. Another option with a gas system is dehydration. Glycol absorption and dry bed/molecular sieve are very efficient water removal methods. An alternative option is injecting an antifreeze, such as methanol. Drip pots and coalescers that collect liquid at low points of the system can help protect pressure measuring devices.

Threads Stripped, Broken Pipe Coupling and Incorrect Operations (TSBPC + IO) Interacting Threat Identification

The threat of TSBPC+IO was the second leading cause of incidents involving interactive threats. TSBPC + IO interaction accounted for 53 incidents. Twenty-six (26) incidents in HL lines had the coupling or fitting or connection replaced or redesigned, which indicates an initial faulty design, and incorrect operation. Nine incidents involved issues with the installation of the connection/coupling/fitting, also an incorrect operation. Twenty-seven incidents were associated with excessive vibration or thermal expansion.

TSBPC + IO incidents that occur in above-ground piping are usually caused by a combination of excessive vibration in the piping and improper installation of threaded joints. As was stated in the section for DFW + IO, a number of factors can lead to excess vibration. A common cause of excessive vibration is the high variability of some process that causes pressure variations, and lack of pipe support exacerbates this problem. Localized vibration can also be caused by operating machinery such as pumps and compressors or by bad design. A vortex inducing component, such as a gate valve, can lead to excessive vibration of the downstream segment.

Improper installation of threaded joints is a primary cause of stripped threads. In a buried pipeline, if the pipeline is installed with misalignment of the pipes at couplings or deliberate angle changes at couplings, the line is less able to withstand soil movement. Also, the pipe may pull out of a coupling of a buried coupled pipeline if there is insufficient thrust restraint. The latter can happen during excavation around a buried coupled pipeline.

The flowchart for TSBPC + IO interacting threat identification is presented in Figure 13.

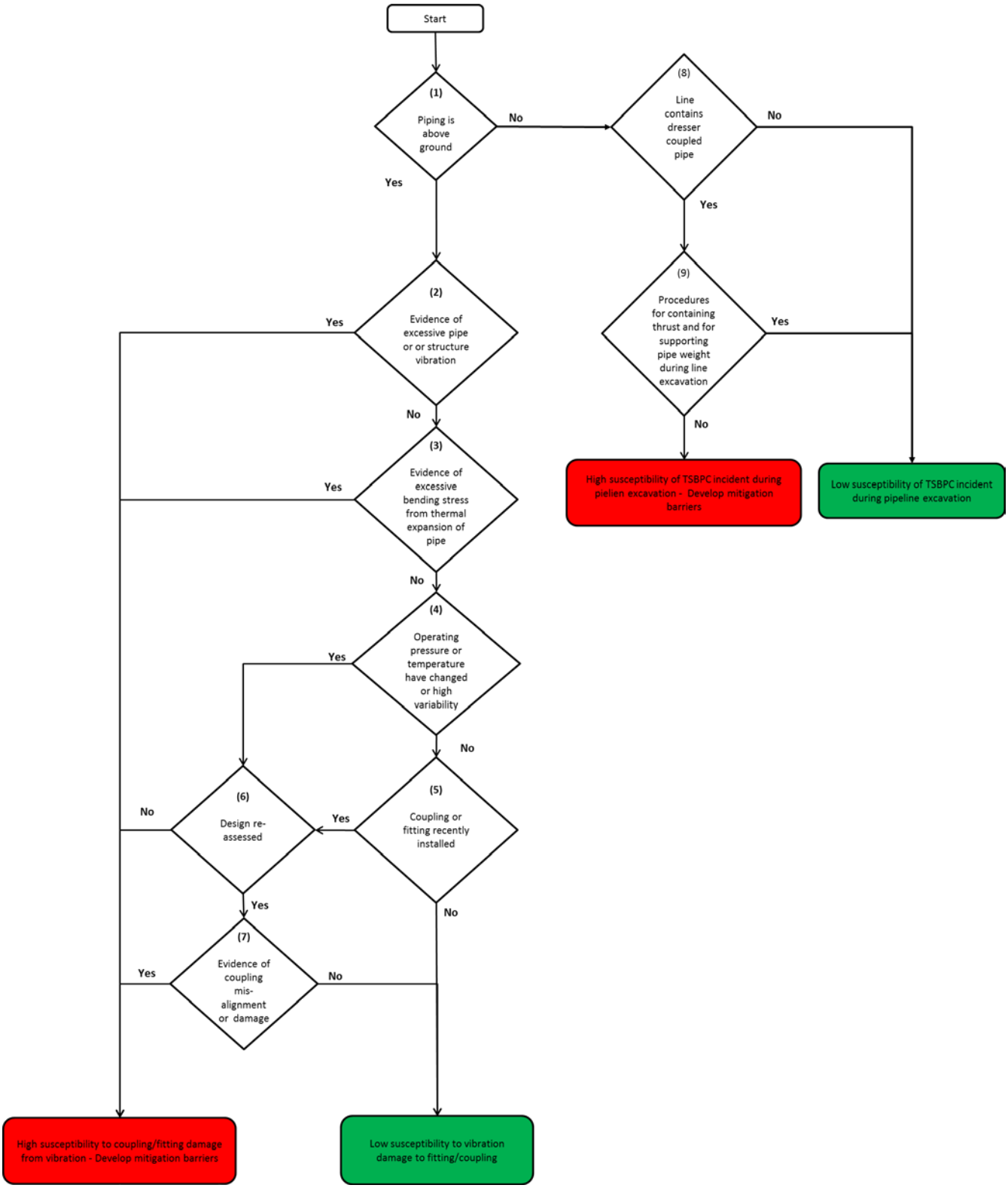


Figure 13. Flowchart for TSBPC + IO Interacting Threat Identification

One of the two branches of the flowchart deals with above-ground piping. The upper part of this branch is aimed at identifying the threat of excessive vibration. If the maintenance group has a maintenance ticketing or log system, it should be reviewed for evidence of lack of support and excessive line vibration. The alignment sheets, as-built drawings and PIDs should be reviewed for gate valves or components that produce a kernel vortex into the flow immediately upstream of the feature being assessed. Line modifications can also be identified in the drawings. Pressure and temperature history should be exported from the SCADA system and reviewed to determine the variability of the process.

Once a line has been identified as susceptible to vibration, it is required to identify any threaded joint. The PFL of the line or segment of interest should be used to identify any threaded joint and then the specifications should be reviewed. In addition, any inspection or maintenance report of the line and/or threaded joint should be reviewed for evidence of misalignment that might compromise the integrity of the joint.

It is difficult to assess the integrity of threaded joints employing a non-invasive method; visual inspection is only useful if the feature shows clear signs of deterioration. It is important to record any sign of deterioration or anomalous condition whenever the joint is de-coupled or given maintenance.

The other branch of the flowchart addresses the threat of coupling failure and thread failure in buried pipelines. The main risk is associated with inadequate restraint to keep the pipe from separating from a coupling. A “pull-out” is possible if an excavation is conducted near or on the pipeline while it is pressurized, and the operator has not adequately prepared for the loss of restraint. Normally, such excavations are limited in length to expose only one or two couplings unless the pipeline is completely depressurized. A secondary risk is associated with the operator not considering need for sufficient support for a pipeline as it is excavated, and not providing enough temporary support to prevent excessive deformation that could lead to a pull-out.

The mitigative barriers aimed at minimizing line vibration should consider the piping configuration and its natural frequency and the sources of vibration. Solutions could include reconfiguration to change the natural frequency of the piping, installation of vibration dampeners, and isolation of the piping from machinery vibrations. A vibration warning system could be installed.

It may be possible to mitigate damaged threads by providing detailed connection assembly instructions for the personnel involved.

Regarding mitigating the risk of coupling pull-out, a detailed written procedure for excavating a coupled line should be developed. It should consider type of coupling, distance between couplings, pipe diameter, operating pressure, depth of burial, weight of the pipeline, type of coating, and soil density and friction coefficient. The objective is to ensure that thrust is restrained by unexcavated soil and that the exposed span is adequately supported to prevent a pull-out.

Third Party and Incorrect Operations (TP + IO) Interacting Threat Identification

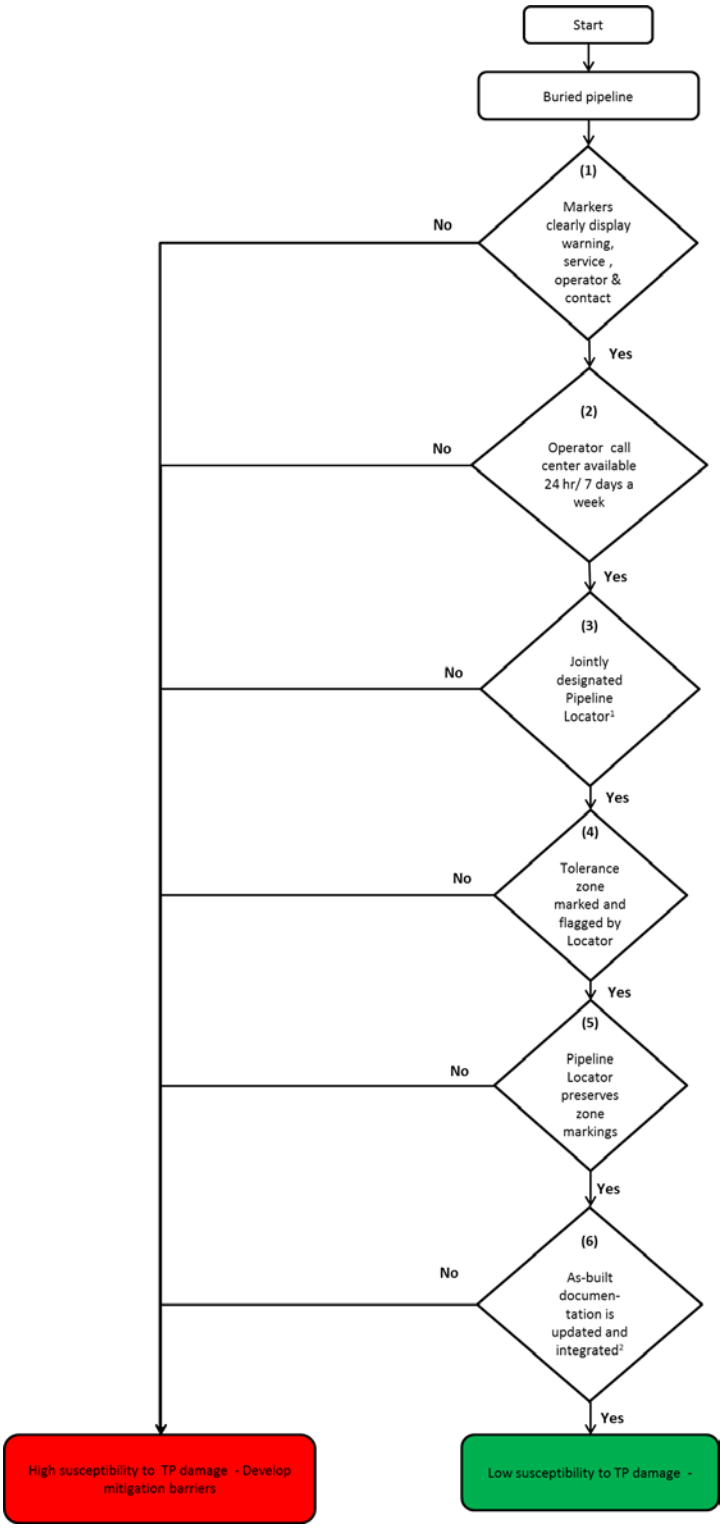
Third party damage (TP) is defined as an immediate failure resulting from mechanical damage caused by an outside force, such as from contact with excavation equipment. The pipeline industry has developed and implemented procedures for communication and monitoring at locations of known excavation by contractors and land owners. When a TP incident happens because one or more of these communication or monitoring procedures has not been appropriately implemented, incorrect operation can be said to have contributed to the incident. Thus TP + IO is an interacting threat.

TP + IO incidents were the ninth leading cause of incidents involving interacting threats. There were 31 such incidents in the incident database. TP+IO incidents are related to pipeline awareness. Many of the TP + IO incidents are simply labeled as '*TPD caused by error in marking line*'. Some incidents occurred due to poor communication resulting in the line not being identified and marked. A variant of the above narrative reports marker destruction; the excavator machinery covers or destroys the markers indicating the pipeline location. Finally, a few cases are caused by the One-call center not communicating or not following up excavation requests.

The factors affecting pipeline awareness are the following [14]:

- Missing ROW markers
- Lack of call center and/or ticket system

The flowchart for the TP + IO interacting threat identification is presented in Figure 14.



(1) Pipeline Locator does not have to be part of pipeline operator personnel
(2) After repair/installation/modification of any facilities (by operator or third party)

Figure 14. Flowchart for TP + IO Interacting Threat Identification

The TP + IO interacting threat identification process requires keeping system maps up to date. It is important to review the repositories of information used by the operation/maintenance personnel (PFL, drawings, GIS Mapping system) for completeness, but also to review the Management of Change (MOC) procedures for adequacy.

Another aspect of the assessment is reviewing the pipeline awareness program in place. The Right of Way (ROW) reports or log needs to be reviewed to make sure markers are maintained visible. The One-call Ticket procedures and training material need to be reviewed. There are two aspects considered in the threat identification assessment that might be difficult to document; the guidelines for data provision from the operations/maintenance personnel and definition of the Locator role and responsibilities. This might require interviewing personnel of the pipeline operators.

It is recommended to observe the safeguards embodied in API RP 1162 and API RP 1166 to mitigate the likelihood of TP + IO.

- In response to a one-call ticket, inspect the proposed excavation site.
- Establish whether or not the pipeline could be impacted.
- Establish temporary markers or markings
- Talk to the excavator, explaining the attributes of the pipeline, where the pipeline is located, and what the markers mean.
- Agree on when digging is to start.
- Provide an on-site observer when excavation is taking place.
- Specify a zone within which hand-digging is required to expose the pipeline.
- Specify structural support requirements for the pipeline.
- Do not withdraw locator/observer from the location until all excavation has been completed.

Threads Stripped, Broken Pipe Coupling and Third Party (TSBPC + TP) Interacting Threat Identification

Any protrusions from the line are at risk of being impacted during excavation works, particularly when the excavator is digging parallel to an existing pipeline with a backhoe. Small diameter fittings and connections are particularly susceptible to breaking from direct impacts or compaction of soil on top of them. The threat of TSBPC+TP was the fourth leading cause of incidents involving interacting threats. TSBPC + TP interaction accounted for 47 incidents. The majority of the narratives report a small diameter connection protruding from the pipeline being hit by a backhoe while exposing the line[10]. A variant is an above ground or partially covered

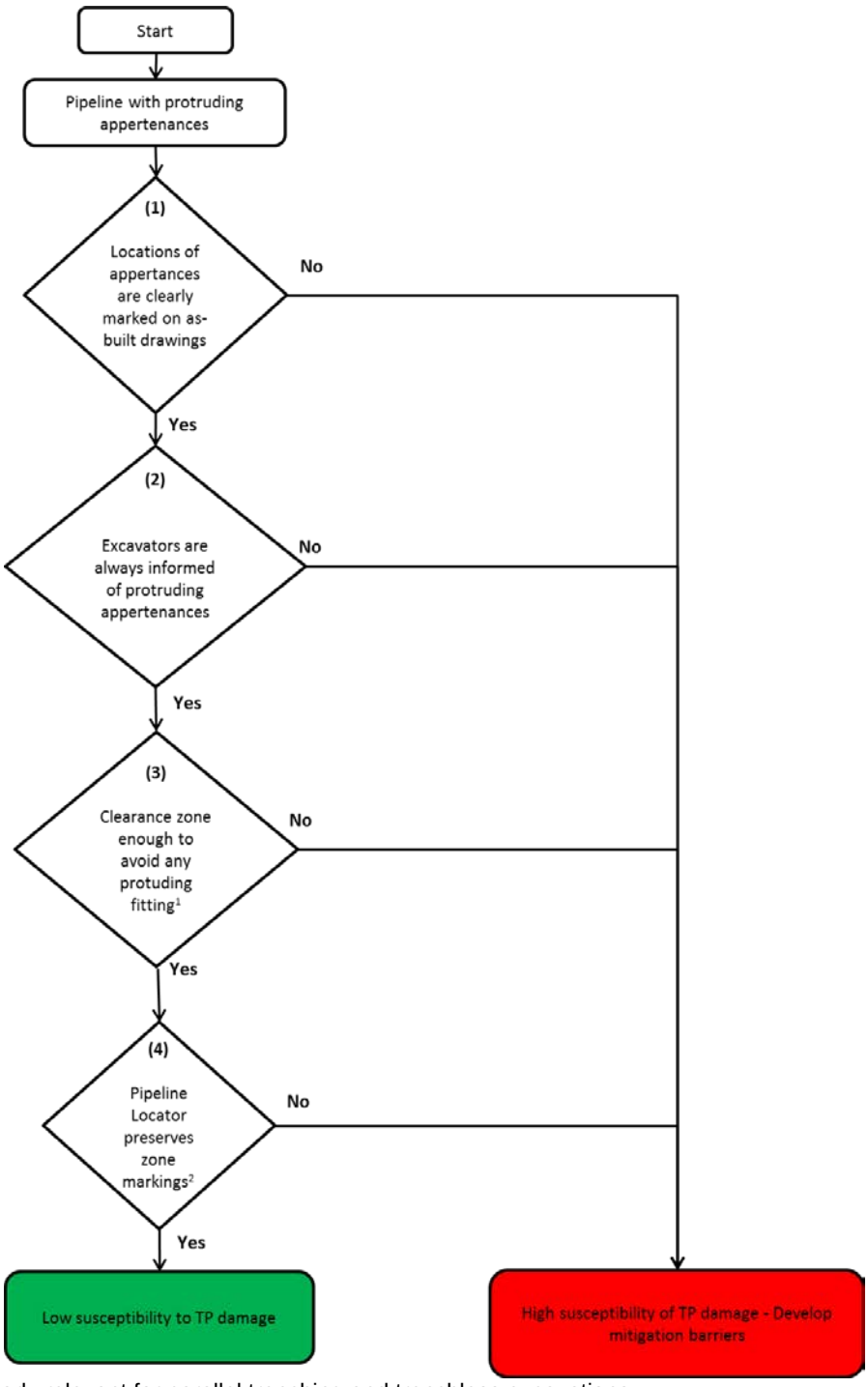
[10] A small set of incidents involves vehicles or objects or cattle impacting above ground valves; this scenario is not covered in the assessment.

small diameter protrusion that is hit or run over by equipment or vehicles. In the majority of cases the contractor hit the protrusion because he was operating equipment too close to the pipe.

The factors that influence protrusion impact during excavations are:

- Out-of-date PIDs or line mapping
- A corporate policy of reactive information provision
- Not enough clearance to avoid fitting or markers not preserved during for the duration of the works

The flowchart for the TSBPC + TP interacting threat identification is presented in Figure 15.



(1) Particularly relevant for parallel trenching and trenchless excavations
(2) Pipeline Locator does not have to be part of pipeline operator personnel

Figure 15. Flowchart for TSBPC + TP Interacting Threat Identification

The mitigative measures to minimize TSBPC + TP require maintaining accurate as-built drawings showing locations and nature of appurtenances. In addition, the pipeline operator is advised to review the as built drawings with excavators involved in each excavation activity.

The operator and excavator must designate a Pipeline Locator to monitor the progress of the excavation and preserve the marking of any zone that is to be hand-excavated.

Heavy Rains or Floods and Earth Movement (EM + HRF) Interacting Threat Identification

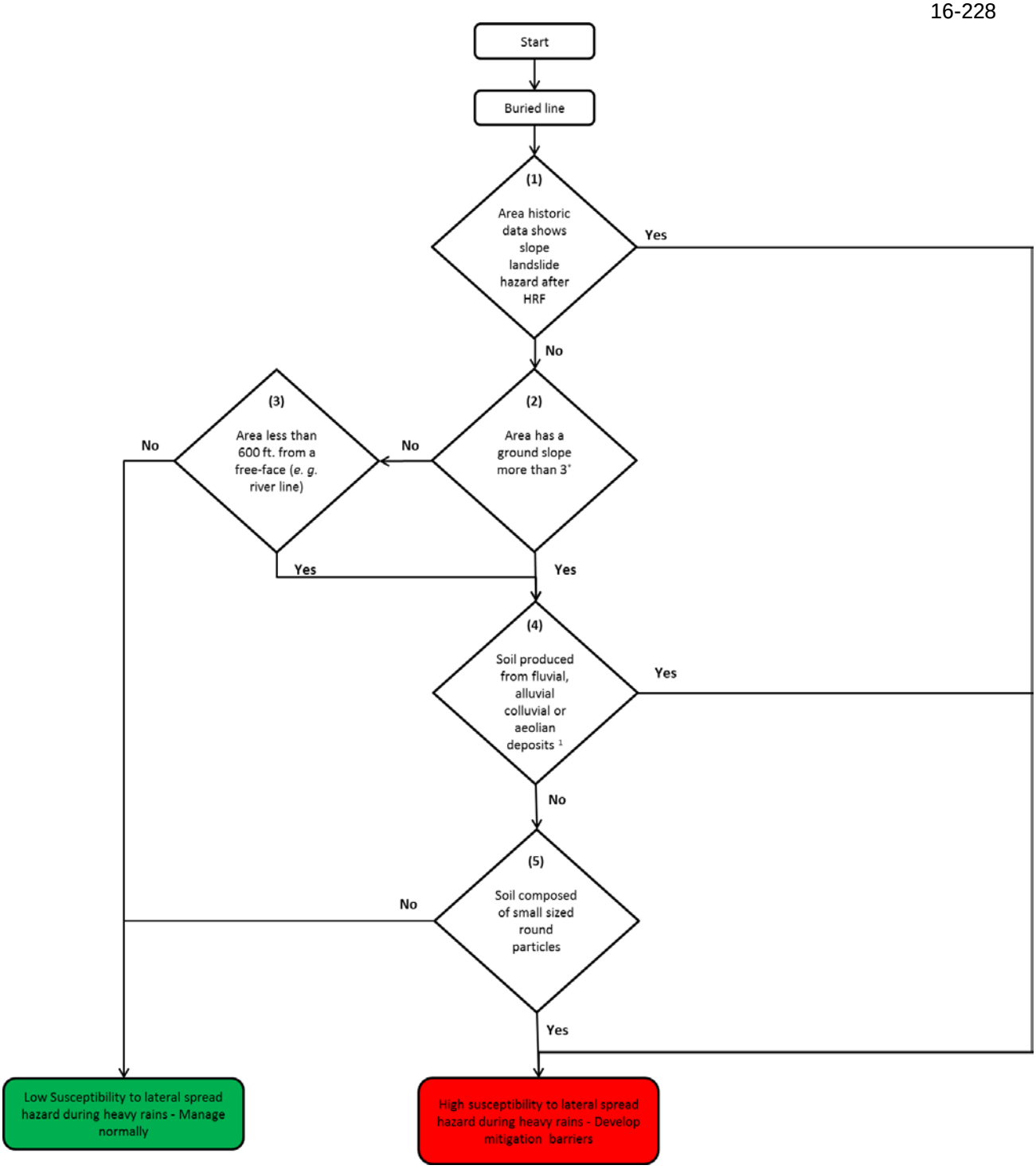
The system considered for this system is a buried pipeline. The sequence of events shows that there must be an external load already present for the mudslide to occur.

Heavy rains can sometimes cause soil to become saturated and thereby contribute to its movement. EM + HRF incident narratives report mudslides resulting from saturated unstable soil layers. The EM + HRF interaction accounted for a total of 29 incidents making it the thirteenth most frequent cause of incidents involving interacting threats. Most of the incidents were caused by landslides or mudslides in sloped terrain or near open faces[11]. Kiefner considered this equivalent to a liquefaction with a lateral spread scenario [15].

The soil susceptibility to liquefaction is affected by its granulometry and compactibility. Some empirical guidelines to predict soil liquefaction are available but require a formal soils characterization [16]. For lateral spread to occur, the pipeline needs to be buried in sloped terrain or be near an open face[12]. To evaluate these two conditions, Kiefner decided to use the guidelines used in [15].

The flowchart for EM + HRF interacting threat identification is presented in Figure 16.The flowchart consists of five logical tests. The first logical test checks for historical data for mudslides; it is then followed by two logical test that check for slopped terrain or a nearby open face. The last two tests check for the soil susceptibility for liquefaction.

[11] Four incidents were caused by underwater mudslides; this scenario is not considered in the threat identification process.
[12] If the soil liquefies and no external load is applied (no slopped terrain or nearby open face) then the line is susceptible to “float”. This buoyancy effect is not reflected in the HRF + EM incident narratives. Kiefner estimates the resulting loads from the buoyancy of a segment of the line are not sufficient to over-stress the pipe



(1) Soil created by sedimentation in rivers and lakes (fluvial or alluvial), by deposition of debris or eroded material (colluvial), or by wind action (aeolian).

Figure 16. Flowchart for EM + HRF Interacting Threat Identification

The EM + HRF interacting threat identification assessment requires reviewing the incident history for any background on landslides in the area. The assessment for lateral spread susceptible areas would be conducted using pipeline alignment maps, geologic maps, stereo aerial photographs, and available geotechnical data. However, some authors warn that it is unusual to have sufficient subsurface information to fully characterize types and locations of pipeline alignment. The same authors provided guidelines for identifying areas with low likelihood for significant lateral spread displacement [15]; (1) areas with ground slope less than 3° and (2) areas at a distance more than about 50 times the pipe diameter from a free-face or bank height. These guidelines were integrated into the flowchart. The terrain slope and distance to other features are available in most alignment sheets, but GPS Mapping tools are particularly helpful for visualization.

The third step requires assessing the potential for soil liquefaction in the lateral spread susceptible areas, which is dependent of soil density, grain size distribution, burial depth and presence of ground water. A formal study would require performing a standard penetration test (SPT) and a cone penetrometer test (CPT) to collect site specific information, but soil borings and test pits are generally reserved for pipeline trench excavation studies. A more general guideline was adopted for the flowchart; evenly distributed small particle soils and granular soils loosely deposited in the past 500 years (river banks, flood plains, deltaic zones, etc.) and should be considered for further characterization. Flood plains and river banks are generally identified in alignment sheets and GPS mapping tools. General soil categorization (fluvial, colluvial, etc.) and properties can also be found in soils survey databases, like the one made available by the National Resources Conservation Services (NRCS) in the U. S [17].

Regarding mitigating the exposure to the threat of EM + HRF, the following factors can be considered. Pipeline burial depth is the main preventive measure against the earth movement hazard since it helps prevent the line being washed out in the event of a lateral spread. Pipeline movement monitoring devices might prove ineffective in preventing an EM + HRF incident since such incident does not involve a gradual displacement of the line. Standpipe piezometers can be used to monitor pore-water pressure, which is a useful indicator of impending landslide activity. Finally, soil stabilization is a preventive measure that directly addresses the lateral spread threat.

Threads Stripped, Broken Pipe Coupling and Earth Movement (TSBPC + EM) and Defective Girth Weld and Earth Movement (DGW + EM) Interacting Threat Identification

Soil movement, such as subsidence or landslides, results in an increase in the axial force applied to a pipeline. Defective girth welds are susceptible to failure from the high axial stress even though they may not be critical at the axial stress levels associated with internal pressure (0.3

times hoop stress in a buried pipeline). Dresser couplings act like defective girth welds in that they are susceptible to failure when subjected to axial movement (often from lateral movement of the pipeline). Mechanical couplings provide a pressure seal but offer negligible axial strength (e.g., only friction resistance). Earth movement that imparts axial movement to a pipeline could cause pipe to pull out of mechanical couplings.

The TSBPC + EM threat interaction accounted for 31 incidents, making it the eighth leading cause of incidents involving interacting threats. In all cases, except one, soil subsidence or lateral spread overstressed a coupling or nipple. A subset of the cases is associated to cold weather. Another subset is associated with ground subsidence after heavy rains. No incidents report soil subsidence caused by nearby mining or water drafting, nor associated with permafrost degradation (which is a recent phenomenon).

The DGW + EM threat interaction accounted for 29 incidents. This interaction was the eleventh most frequent cause of incidents arising from interacting threats. All narratives report pipeline displacement because of soil subsidence or lateral spread and failure at a defective girth weld. The DGW + EM threat interaction has many similarities with TSBPC + EM; the incident is provoked by soil subsidence or movement, and a weak link in the affected pipeline segment. In this case, the weakest link is a defective girth weld.

In both cases, earth movement is caused by soil subsidence, which might be caused by any of the following factors:

- Soil liquefaction
- Nearby mining
- Frost heave or thaw settlement
- Permafrost degrading

The flowchart for TSBPC + EM interaction threat identification is presented in Figure 17.The first section assesses the soil subsidence susceptibility and has two branches depending of the type of climate; for cold/artic terrains, the flowchart checks for thawing and permafrost degrading; for any other type of terrain the flowchart checks for soil liquefaction susceptibility and nearby mining. It must be assumed that a mechanically coupled pipeline cannot withstand significant axial tensile stress and will offer little or no resistance to axial tensile strain. Therefore, the threat of earth movement must be mitigated, since the risk of the pipeline parting upon lateral displacement is substantial.

The flowchart for evaluating the threat of DGW + EM is presented in Figure 18. The subsidence factors to consider are identical to those for the threat of TSBPC + EM, but a section is added at the end that checks for girth weld integrity. The threat of subsidence causing a girth weld to

fail is affected by the integrity of the girth weld because a sound girth weld that overmatches the strength of the base metal will not be a weak point in the pipeline. In contrast to the situation involving a pipeline with mechanical couplings, a pipeline with sound girth welds can withstand substantial axial stress, and it poses substantial resistance to lateral deformation of the pipeline.

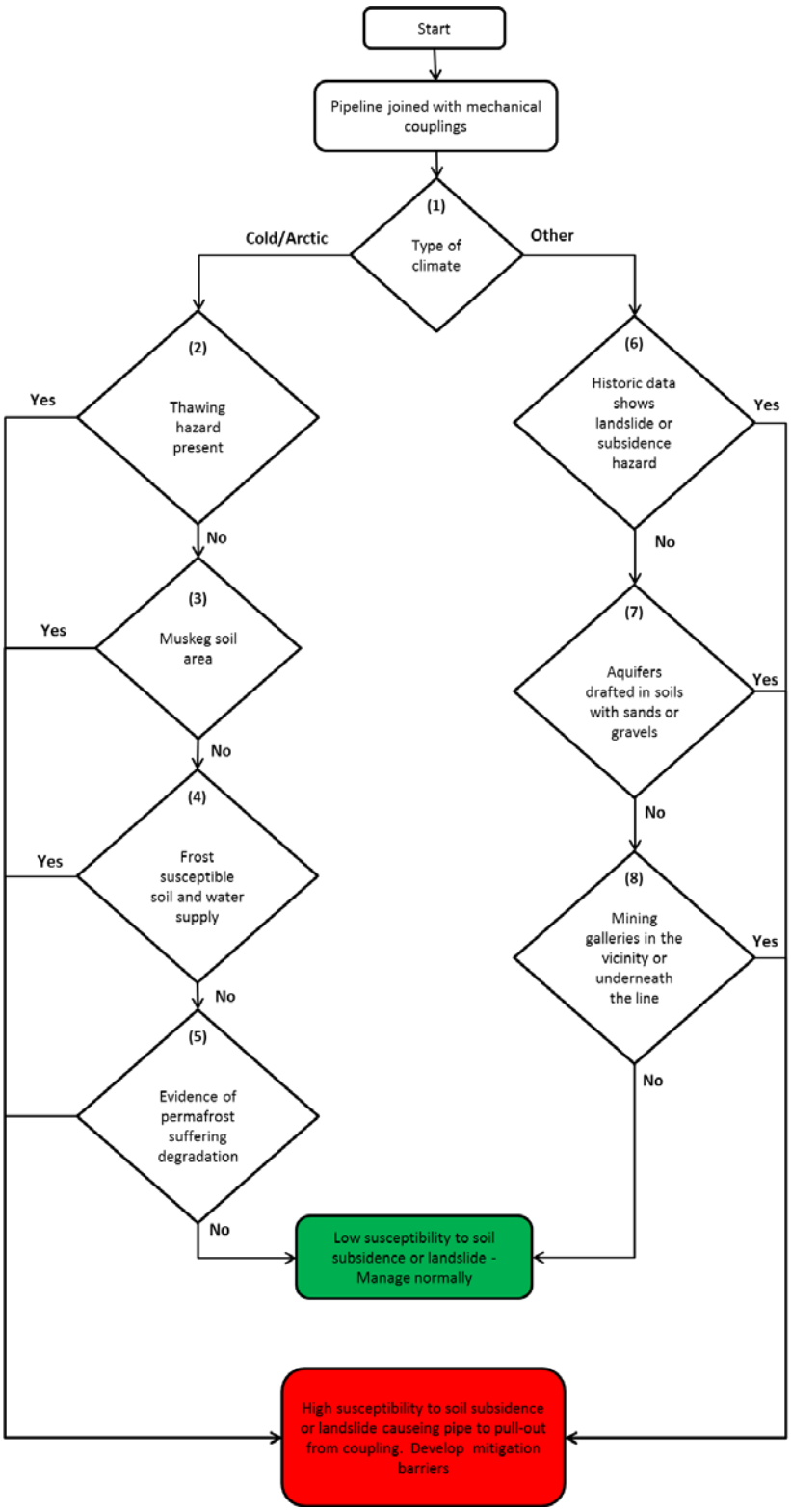
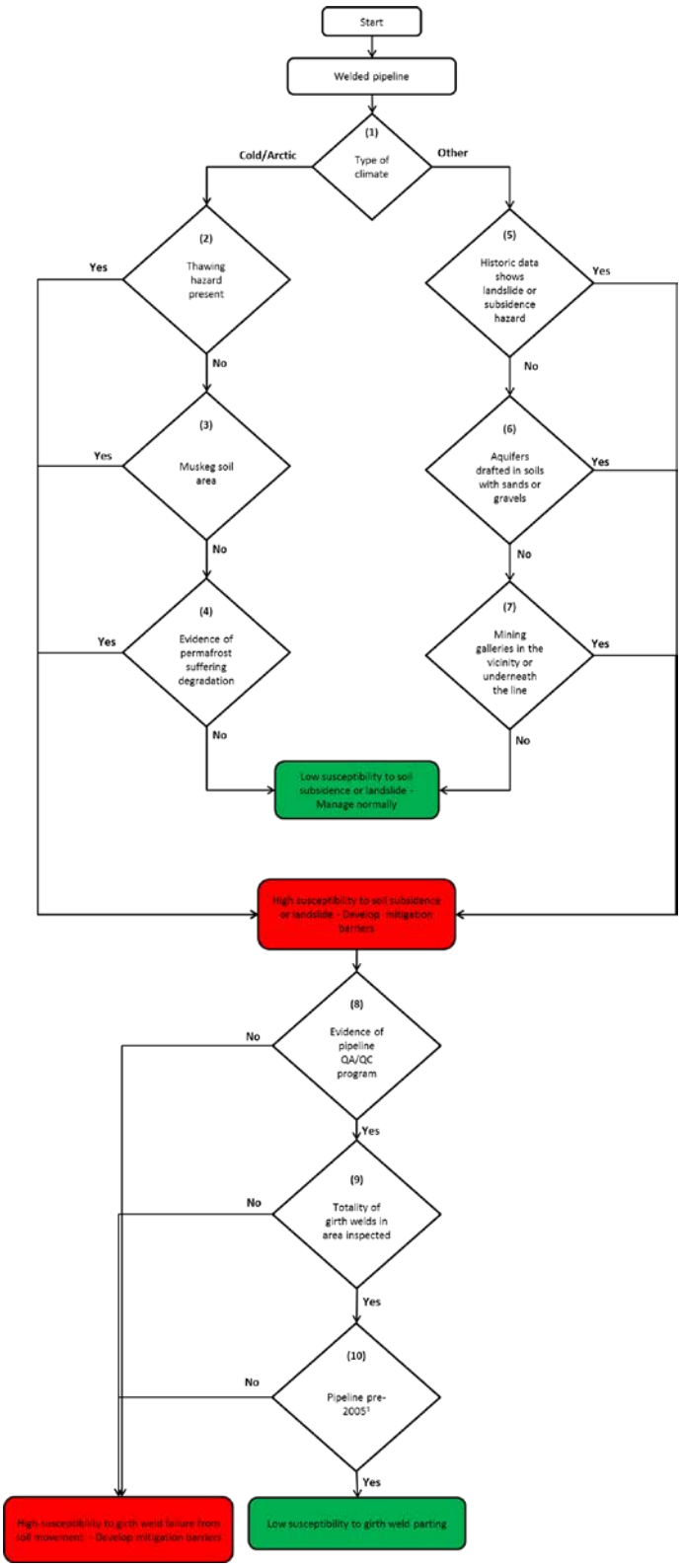


Figure 17. Flowchart for TSBPC + EM Interacting Threat Identification



(1) Or any pipeline where girth weld strength tends to under-match that of base metal.

Figure 18. Flowchart for DGW + EM Interacting Threat Identification

The TSBPC/DGW + EM interacting threat assessment requires determining the type of terrain and the soil overall properties. This information might be available in public survey databases, such as the one made available by the National Resources Conservation Services (NRCS) in the U. S [17]. In addition, it is necessary to determine if there are any nearby underground galleries or aquifers being drafted. This information might be available in local records and might require a review of external information sources.

Once the soil liquefaction susceptibility has been identified, the TSBPC + EM process requires identifying any mechanical couplings in the segment of the line. The PFL of the line or segment of interest should be used to identify the presence of such components. In addition, any inspection or maintenance report of the pipeline and/or couplings should be reviewed for evidence of misalignment that might further compromise the integrity of the couplings.

The assessment process for DGW + EM requires checking for evidence of the QA/QC program during the constructions phase (the qualification of the welders and the welding procedures) and evidence of the inspection of the 100% of the girth welds. Poor quality electric arc welds or any acetylene girth welds will be more at risk of failure than sound electric arc girth welds.

A simple array of strain gauges can characterize the distribution of tensile and compressive strains in a pipe with girth welds. It can provide baseline readings for later calculations of stress in the pipe. A geometrical ILI tool can also detect bending and buckling of the line and, if instrumented with a geo positioning system, can also detect line displacements. Also, operators can employ the analytical techniques presented in Appendices C, E, and G to assess the limits on pipeline displacement that must be observed to avoid girth weld failures.

The girth welds of a section of the pipeline can be inspected with UT, MFL or EMAT ILI tools or by radiography if exposed during ITD inspections. ILI vendors report advances in MFL and EMAT technologies that allow ILI tools to identify and characterize weld defects. In particular, the EMAT tool capabilities seem promising; its detection reliability remains to be validated.

Pipeline burial depth is the main mitigative measure to reduce the earth movement hazard, since it helps preventing the pipeline being move out of position in the event of soil liquefaction. In the earth movement scenarios envisioned here the lateral displacement or sinking of the pipeline might be gradual. Hence, pipeline monitoring devices are valid mitigative barriers. Inclinometers are useful for detecting the onset of soil movement. The limits on earth movement that can be tolerated are obviously different for the coupled versus the girth-welded pipeline.

Threads Stripped, Broken Pipe Coupling and Heavy Rain or Flood (TSBPC + HRF) and Defective Girth Weld and Heavy Rain or Flood (DGW + HRF) Interacting Threat Identification

Heavy rains and floods (HFR) can produce scouring of backfill, floatation of a pipeline, and vortex shedding in water current. The resulting lateral forces can cause pipes to pull out of mechanical couplings, breakage or thread stripping of threaded pipe or fittings, and ruptures of pipelines with defective girth welds. Storm surges and high winds associated with hurricanes can cause floatation and impacts from flying debris. The associated forces can cause breakage or thread stripping of threaded pipe or fittings, and ruptures of pipelines with defective girth welds. Pipelines with mechanical couplings are usually not located in areas affected by hurricanes (i.e., offshore or near a coastline). The effects of heavy rains and floods on piping and pipelines are similar to those described in the TSBPC/DGW + EM section except that in the case of heavy rains and floods, the displacement can occur rapidly.

TSBPC+HRF incidents were the tenth most frequent cause of incidents involving interacting threats. The TSBPC + HRF interaction accounted for 32 incidents; the common element in the majority of the incidents was line shifting. Some incidents involved pipes being pulled out of coupling. Others involved breakage of threaded pipes or fittings or stripped threads. At least 12 incidents happened during a hurricane. One incident happened during a tornado. Six cases involved ground shifting and hence have the EM component.

DGW+HRF incidents were the seventeenth most frequent cause of incidents involving interacting threats. The DGW + HRF interactions accounted for 18 incidents. Six incidents were caused by the pipeline being exposed to river/flooding currents. A similar number of incidents were caused by the pipeline being exposed to high winds and tidal surge from hurricanes. The vast majority of DGW + HRF have been reported since 2005; most happen during hurricanes.

The flowchart for TSBPC + HRF interacting threat identification is presented in Figure 19. Tests 1 and 2 address pipelines with mechanical couplings and whether or not they are exposed to the possibility of flooding. Tests 3 and 4 address threated piping and fittings and whether or not such systems are exposed to being damaged by flooding, storm surge or high winds.

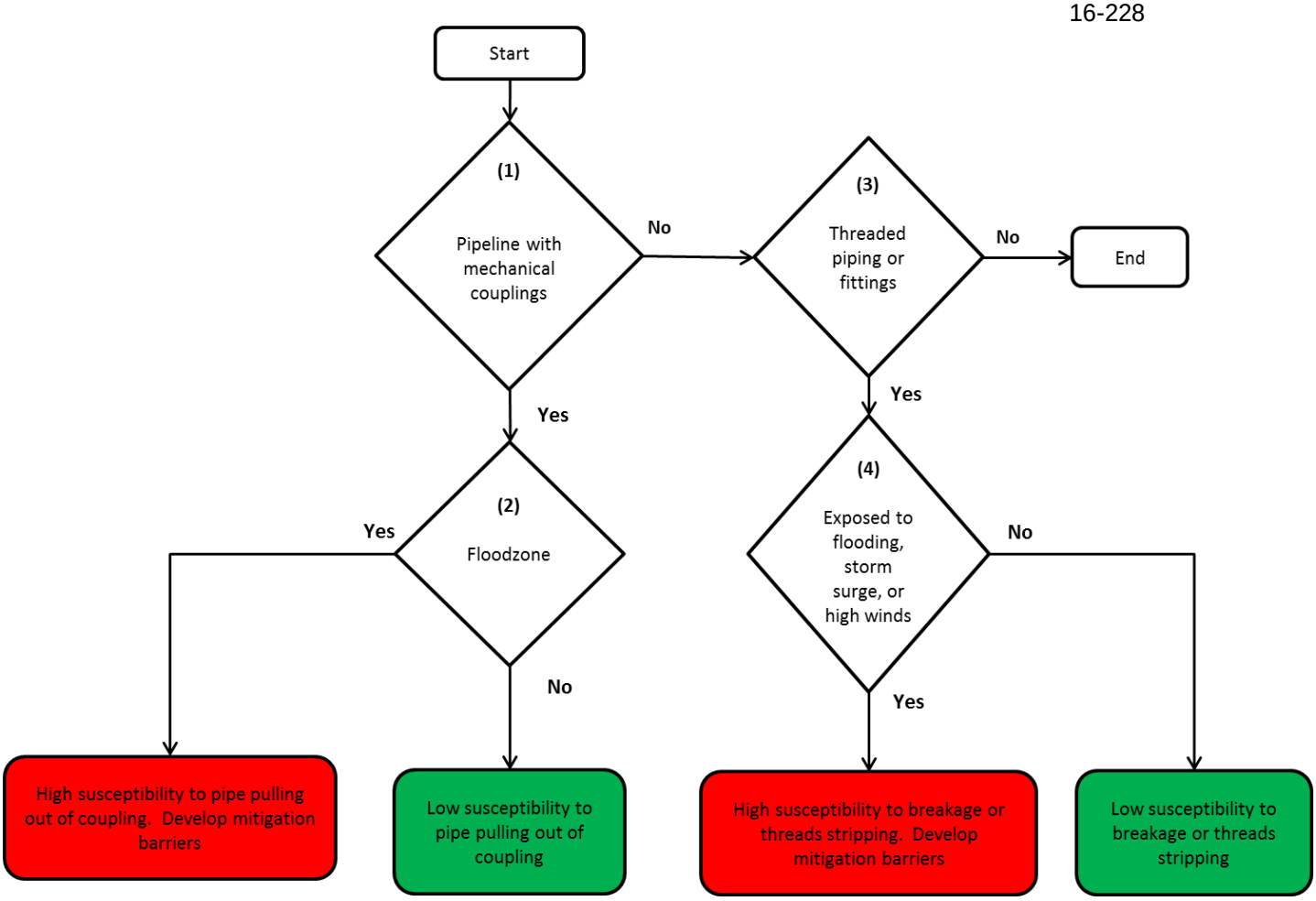
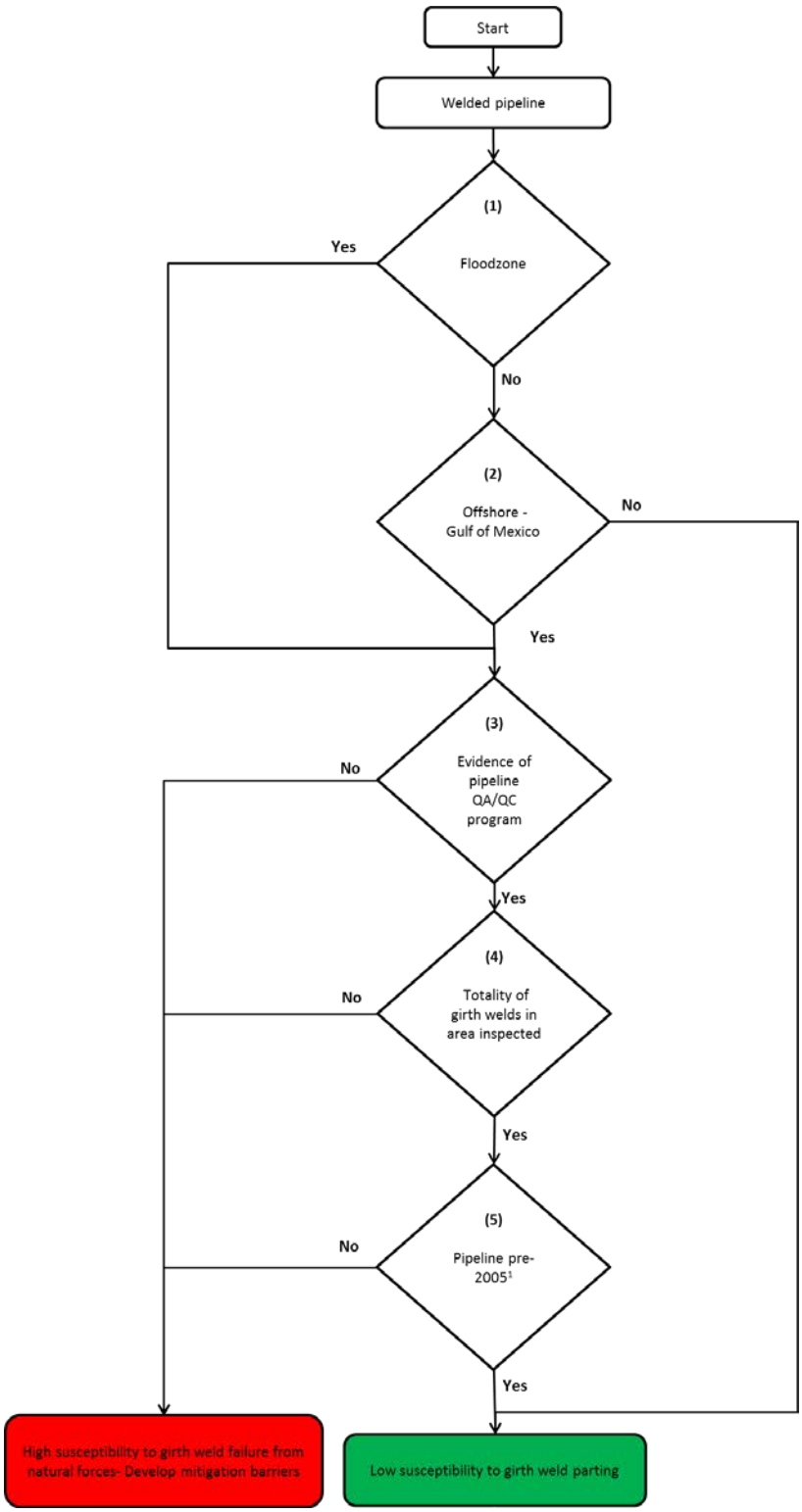


Figure 19. Flowchart for TSBPC + HRF Interacting Threat Identification

The flowchart for DGW + HRF interacting threat identification is presented in Figure 20.



(1) Or any pipeline where girth weld strength tends to under-match that of base metal.

Figure 20. Flowchart for DGW + HRF Interacting Threat Identification

If the pipeline is exposed to either flooding or storms offshore, the integrity of the girth welds is assessed to determine whether or not defects or weld strengths under-matching that of the base metal can be present. If either can exist, mitigation is needed.

The TSBPC/DGW +HRF interacting threat assessment requires determining if the line passes through a flood-zone. This information might be available in local records and might require a review of external information sources. In the case of girth welded pipelines, records of welding inspections and tests are also required to assess the likelihood of the girth welds being defective.

The TSBPC + HRF process requires identifying and locating pipelines with mechanical couplings and piping systems with threaded joints. The PFL of the line or segment of interest should be used for these purposes. In addition, any inspection or maintenance report of the pipeline and/or threaded piping should be reviewed for evidence of misalignment that might compromise their integrity.

The assessment process for DGW + HRF requires checking for evidence of the QA/QC program during the constructions phase (the qualification of the welders and the welding procedures) and evidence of the inspection of the 100% of the girth welds.

It is difficult to assess the integrity of threaded joints employing a non-invasive method; visual inspection is only useful if the feature shows clear signs of deterioration. It is important to record any sign of deterioration or anomalous condition whenever the joint is de-coupled or given maintenance.

A simple array of strain gauges can characterize the distribution of tensile and compressive strains in a pipeline. It can provide baseline readings for later calculations of stress in the pipe. A geometrical ILI tool can also detect bending and buckling of the line and, if instrumented with a geo positioning system, can also detect pipeline displacements. Appendix C presents methods to assess strain on a pipeline displaced from its normal alignment by external forces.

The girth welds of a section of the pipeline can be inspected with UT, MFL or EMAT ILI tools or by radiography if exposed during ITD inspections. ILI vendors report advances in MFL and EMAT technologies that allow ILI tools to identify and characterize weld defects. In particular, the EMAT tool capabilities seem promising; its detection reliability remains to be validated.

Pipeline burial depth is an effective mitigative measure against wash out, since it helps preventing the pipeline being moved out of position in the event of soil liquefaction. Operators may want to consider replacing mechanically-coupled pipelines in flood zones.

Gasket Failure and Incorrect Operations (GF + IO) Interacting Threat Identification

GF + IO incidents happen from a combination of improper gasket installation and a change of process variables that speed up the degradation of the gasket. Incidents solely caused by an improperly tightened flanged joint should not be classified as GF + IO, since they are only caused by improper installation (IO) without gasket or O-ring malfunction.

The interacting threat of GF+IO was the sixth most frequent cause of incidents involving interacting threats. GF + IO interaction accounted for a total of 45 incidents. Twenty-nine incidents were caused by deficient design or wrong specification of the gasket. Twelve incidents reported evidence of improper gasket installation. Six incidents were associated with a defective gasket and incorrect operation of the pipeline/system.

The assessment considers that improper tightening of the flange or off-center installation of the gasket can result in radial cracking of the gasket. Another consideration is that a change of service or thermal cycling or pressure increase can provoke accelerated degradation of the gasket. The resulting flowchart for GF + IO interacting threat identification is presented in Figure 21.

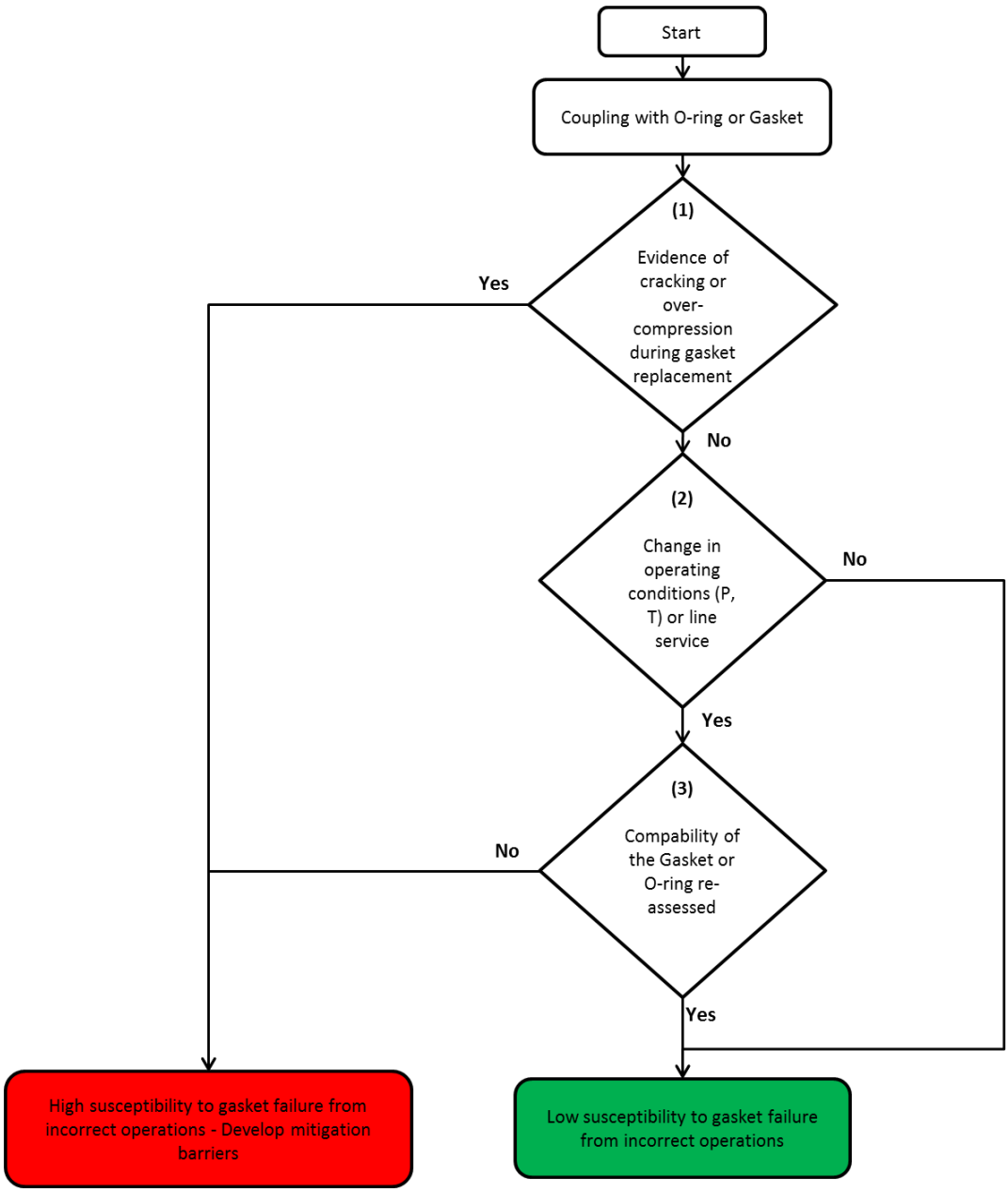


Figure 21. Flowchart for GF + IO Interacting Threat Identification

The assessment necessitates reviewing the adequacy of the gasket specifications. Hence the starting point of the analysis is the gasket specifications sheet. The pipeline service and operating conditions can be retrieved from the PFL. The temperature and pressure history needs to be exported from the SCADA system to evaluate the variability of the process. The last item to consider is any sign of deterioration or failure of the gasket, which may be documented in maintenance reports or logs. If not documented, the necessary information may be obtained from interviews of the maintenance personnel.

It is difficult to assess the integrity of a gasket using a non-invasive method. It is very important to document any sign of deterioration or anomalous condition whenever the gasket is replaced. Concerning mitigation barriers: The GF + IO threat requires an improper gasket installation, hence an appropriate procedure for flange bolt tightening is the main mitigative measure. In addition, the maintenance team must develop reliable standards for matching gasket material to the type of service and implement a program of periodic visual inspection of flanged joints. Documents on flange bolt tightening and gasket/fluid compatibility are available in the technical literature [18, 19, 20].

Cold Weather and Incorrect Operations (CW + IO) and Threads Stripped, Broken Pipe Coupling and Cold Weather (TSBCP + CW) Interacting Threat Identification

The CW + IO threat was the fifteenth most frequent cause of incidents involving interactive threats. It accounted for 26 incidents. Fourteen CW + IO incidents were associated with water freezing inside a pipe or component. Two incidents may have involved incorrectly operating a gas pipeline in cold weather causing hydrates in the pipeline to freeze, either restricting flow or shutting off flow in the pipeline. This condition often arises downstream of pressure reductions which causes significant cooling effects. The flow restriction or blockage could lead to a pressure excursion and a resulting failure.

In most narratives the preparations for cold weather failed to include draining accumulated water from piping systems and components. If the system has low points (*e. g.* dead legs) and they are not drained in preparation for winter or artic weather, then the system has a high susceptibility for freeze rupture.

It has been noted that a considerable number of CW + IO incidents occurred during the polar vortex of 2014 (also named early 2014 North America Cold Wave) that affected southern states, such as Louisiana and Texas, where operators do not normally implement winter preparation programs; operators should prepare an arctic blast preparation program regardless of the region. The flowchart for CW + IO interacting threat identification is presented in Figure 22.

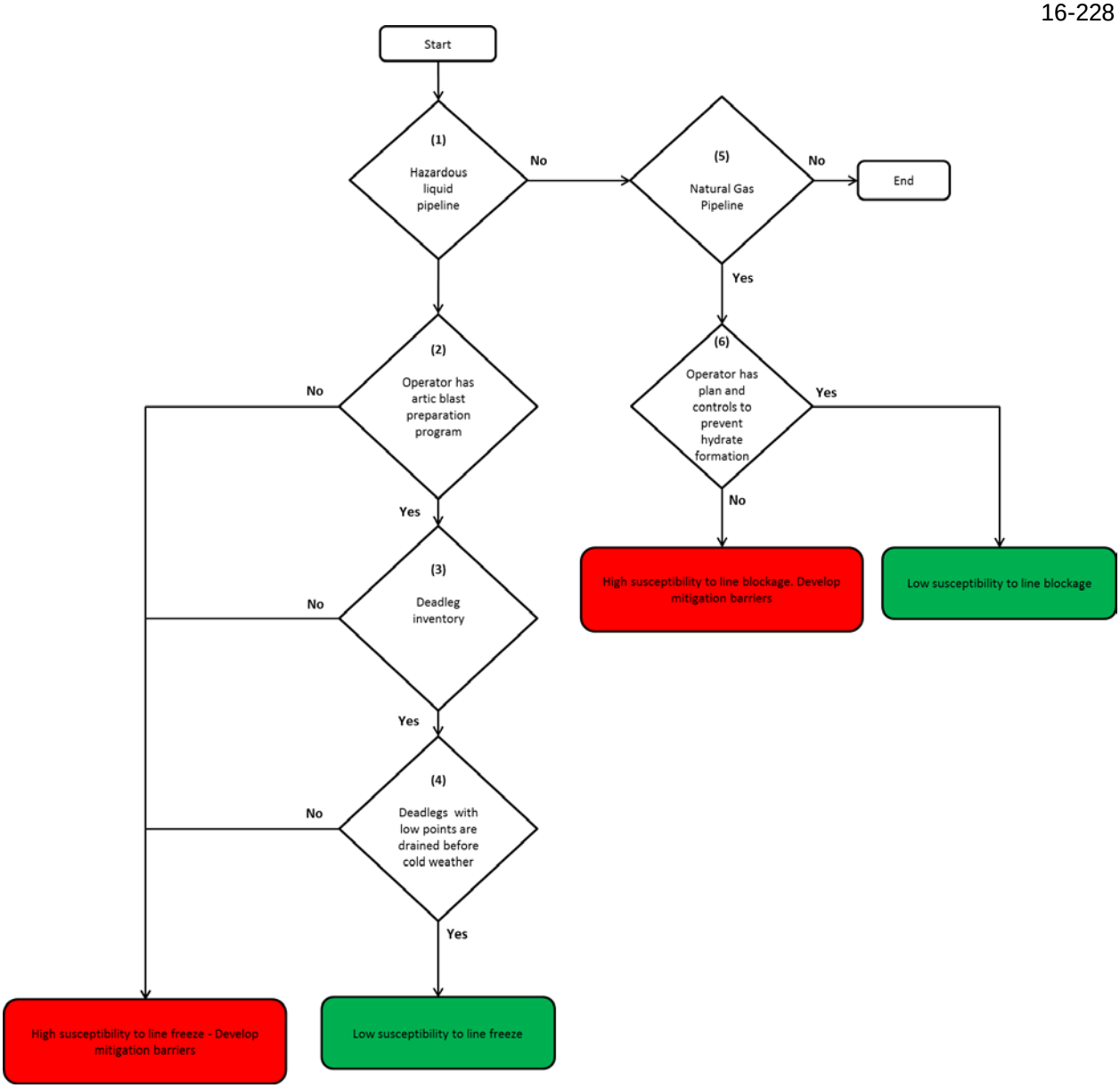


Figure 22. Flowchart for CW + IO Interacting Threat Identification

Figure 22 addresses the likelihood of water freezing in low spots and deadlegs in hazardous liquid pipelines and the likelihood of hydrate formation and line blockage in natural gas pipelines.

The TSBPC + CW interaction was the eighteenth most frequent cause of incidents involving interacting threats. It accounted for 17 incidents that fell in three different categories:

- Incidents that report that a nipple broke from freezing.
- Incidents that report a small-diameter threaded connection being cracked (or flange stressed) by ground frost heave.

- Ice falling from a roof and breaking a small-diameter threaded connection. (This scenario is much more significant in the gas distribution lines, which are not within the scope of this work.)

The flowchart for the TSBPC + CW threat is presented in Figure 23. The figure is intended to address adverse effects of cold weather on pipelines with mechanically-coupled or threaded joints and pipelines with threaded appurtenances. Tests 1 through 4 check for the presence of thaw settlement, frost heave, and/or permafrost hazards that could cause excessive deformation of the pipeline. Test 5 addresses whether or not water is drained from low spots to prevent ice formation in appurtenances.

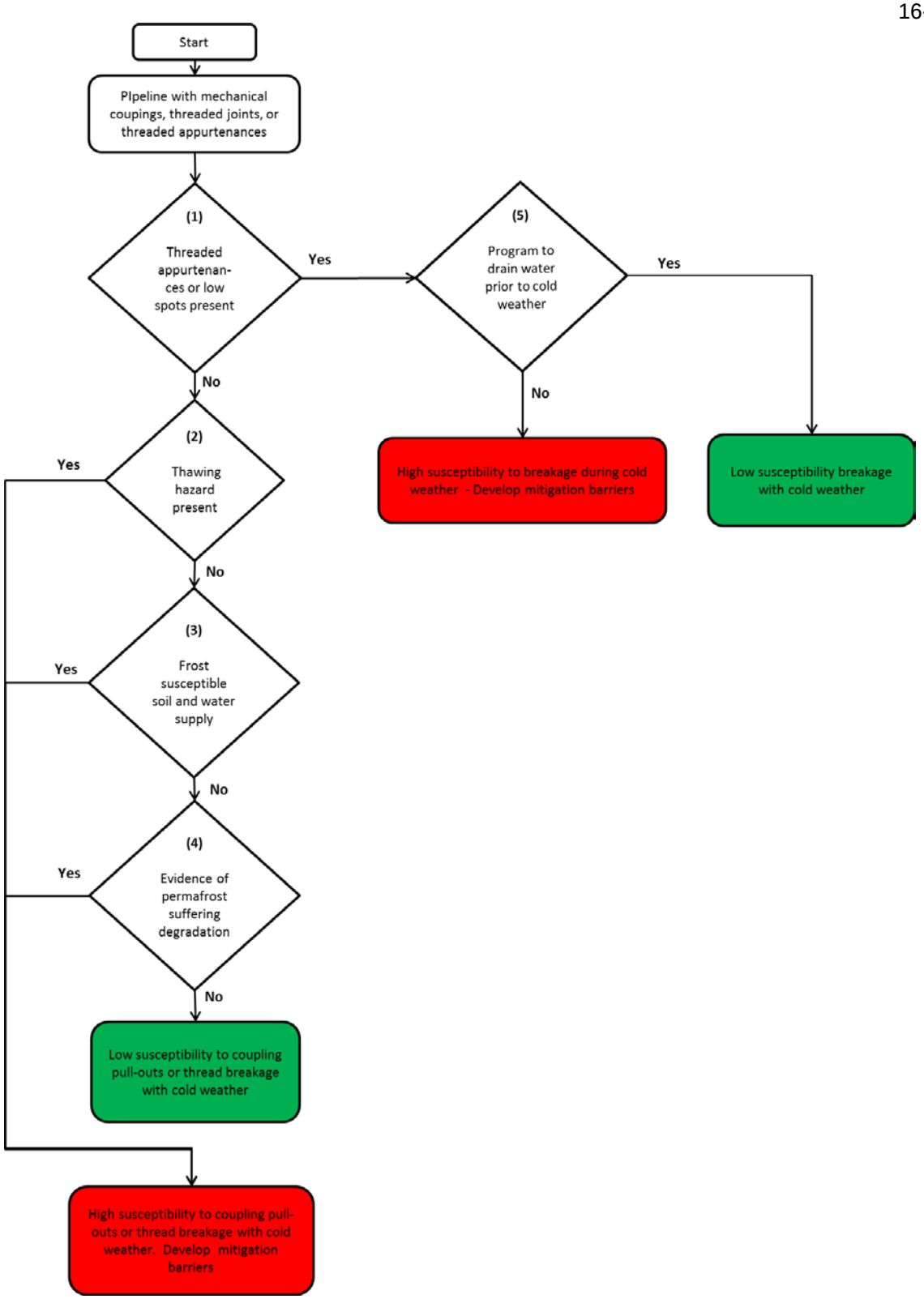


Figure 23. Flowchart for TSBPC + CW Interacting Threat Identification

Data gathering for addressing the CW+IO and TSBPC+CW threats consists reviewing the preparations for cold weather and ascertaining whether or not the pipeline resides in soils that may susceptible to frost heave or thaw settlement. The operator should verify the locations of deadlegs with low points.

For mitigative barriers, the operator should either provide heating or insulation to keep trapped water from freezing or make sure that all water is eliminated prior to the onset of cold weather. Other alternatives are to inject antifreeze or to remove deadlegs and low spots from service to prevent ice formation within the piping. Methods for assessing the likelihood of having water trapped in a deadleg are presented in Appendix J.

With regard to preventing the breakage of threaded piping or the pull-out of pipe from couplings in a mechanically-coupled pipeline buried in thaw-unstable or frost-heave-susceptible soils, the operator might be able to stabilize the terrain to prevent frost heave or thaw settlement. Alternatively, the operator could consider replacing threaded or mechanically-coupled piping or pipelines with welded piping or pipelines.

Third Party and Heavy Rain or Floods (TP + HRF) Interacting Threat Identification

Third-party damage includes incidents resulting immediately from encroachment by outside parties and by pipeline operators and their contractors. But it also includes impacts by debris and objects hurled by high winds or currents. TP + HRF (mechanical damage incidents arising from severe storms and/or flooding) was the tenth most frequent cause of incidents involving interacting threats. The TP+HRF interaction accounted for 30 incidents. The vast majority of the TP + HRF incidents fall into one of the following narratives: (1) during a hurricane a dragged object/structure impacts the pipeline causing an immediate release and (2) during flood remediation operations, third party heavy equipment impacts a pipeline or causes soil instability that put pipelines in contact.

The offshore incidents during hurricane season are the most common narrative and nearly 65% of them occurred when hurricane Ike affected the Gulf of Mexico in 2008. The most common dragged items are anchors, followed by jack up rigs. Unfortunately, the narrative of such incidents is very austere and does not give details on preparations and proximity of the vessel whose anchor was dragged. This case is presented as TP + HRF Offshore below.

The second type of narrative is less common: heavy rains cause flooding in an area and the external impact happens during remediation work. In one case, a farmer breaching levees on his field severed a 4" gas transmission pipeline with a backhoe. In another case, a utilities company provided ways of water egress from a flooded area by perforating under a road (no description how this was achieved is given in the narrative) and this eventually caused a

washout cavern beneath the road which in turn caused the gas pipeline to collapse and conflagrate. This case is labeled TP + HRF Onshore.

Third Party Damage + Heavy Rain or Floods (TP + HRF) - Offshore

During the 2005 and 2008 hurricanes in the Gulf of Mexico, waves were higher and winds were stronger than anticipated and many jack–up platforms were dragged. The main factor affecting the drag susceptibility of a jack up platform was its elevation. For the vessels, the factors are time of advanced warning for a hurricane (some Floating Production and Storage and Offloading vessels require more than 48 hours to unmoor) and the implementation of a multi stage plan for moving it out of the storm path.

For Jack-up platforms the API recommends reviewing wind and wave and water current measurements (metaocean data) to assess the likelihood of a structure to be dragged. The same analysis can be done to assess if a vessel (particularly FPSOs) are on major surge directions relative to the pipeline corridor.

After the major 2005 hurricanes, the American Petroleum Institute (API) reassessed its Recommended Practices (RPs) for industry operations in the Gulf of Mexico. In 2008, API published an update to RP 2SK, Design and Analysis of Station-keeping Systems for Floating Structures, that provides guidance for design and operation of Mobile Offshore Drilling Unit (MODU) mooring systems in the Gulf of Mexico during the hurricane season. API also updated API RP 95J, Gulf of Mexico Jack-up Operations for Hurricane Season, which recommends locating jack-up rigs on more stable areas of the sea floor, and positioning platform decks higher above the sea surface.

API has also issued several new standards that improve structural design and assessment considerations for Gulf hurricanes. These include:

- Recommended Practice 2A-WSD, Planning, Designing, and Construction Fixed Offshore
- Recommended Practice 2GEO, Geotechnical and Foundation Design Considerations
- Recommended Practice 2MET, Derivation of Metocean Design and Operating Conditions
- Recommended Practice 2SIM, Structural Integrity Management of Fixed Offshore Structures

Existing Jack-up structures should be re-assessed using API RP 2SIM, while new structures should comply with API RP 2A-WSD.

For vessels it is important that a hurricane response plan has been implemented that clearly defines the times and prompted actions during the different stages of the crisis. A basic plan has four stages: before the storm, upon imminent arrival of the storm, during the storm and after the storm.

The flowchart for the HRF + TP offshore scenario is presented in Figure 24.

Limitations of the flowchart:

- The flowchart only applies for the Gulf of Mexico.
- The flowchart requires making an inventory of assets that may be dragged and impact the pipeline. Most of those assets will not be owned by the pipeline operator and therefore, it might not be feasible to evaluate if they do not follow the API Recommended Practices or do not have an appropriate response plan. Because these incidents are a major concern for the offshore oil industry, the API is coordinating the efforts to evaluate the preparation measures of all operators in the Gulf of Mexico.

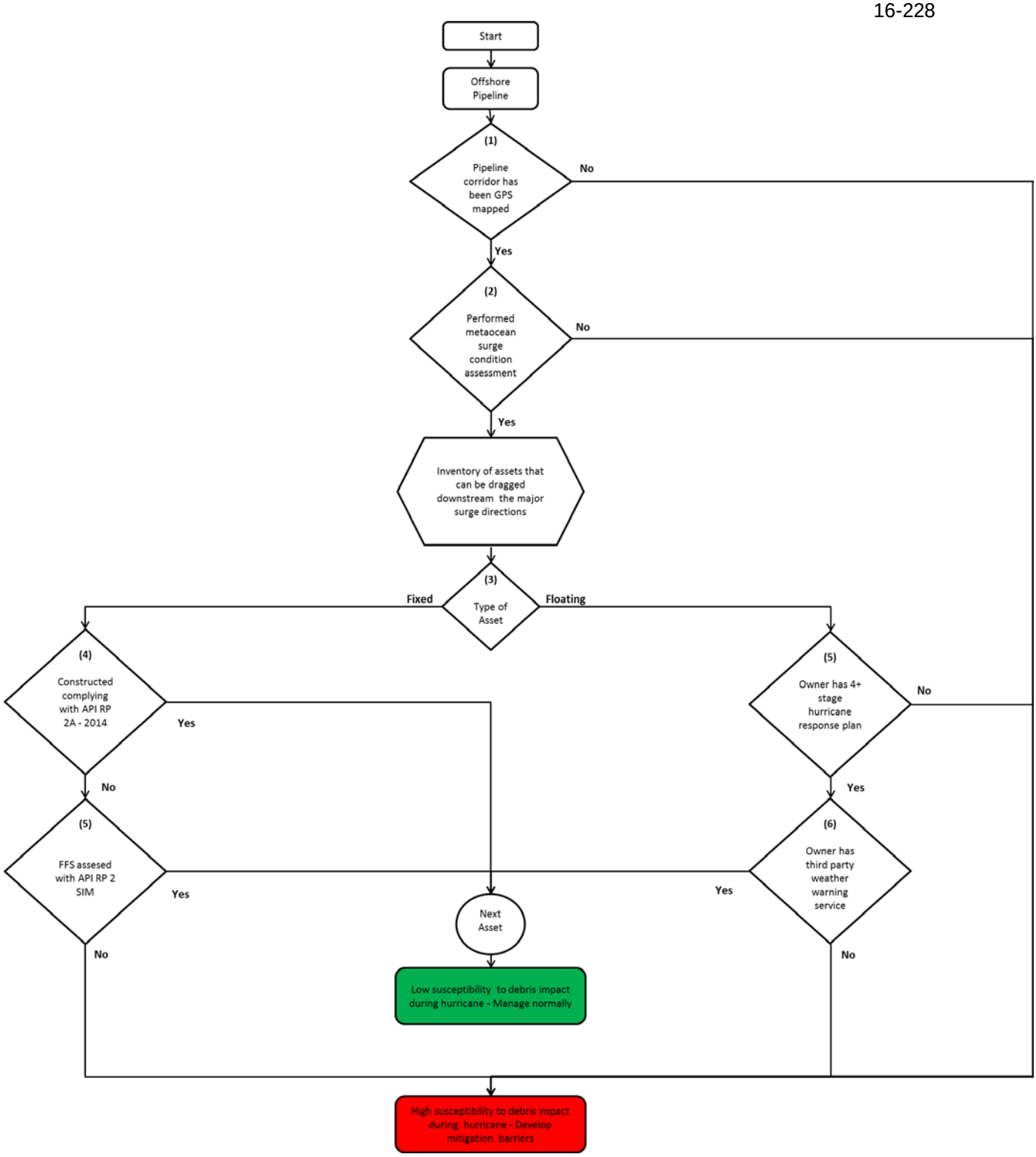


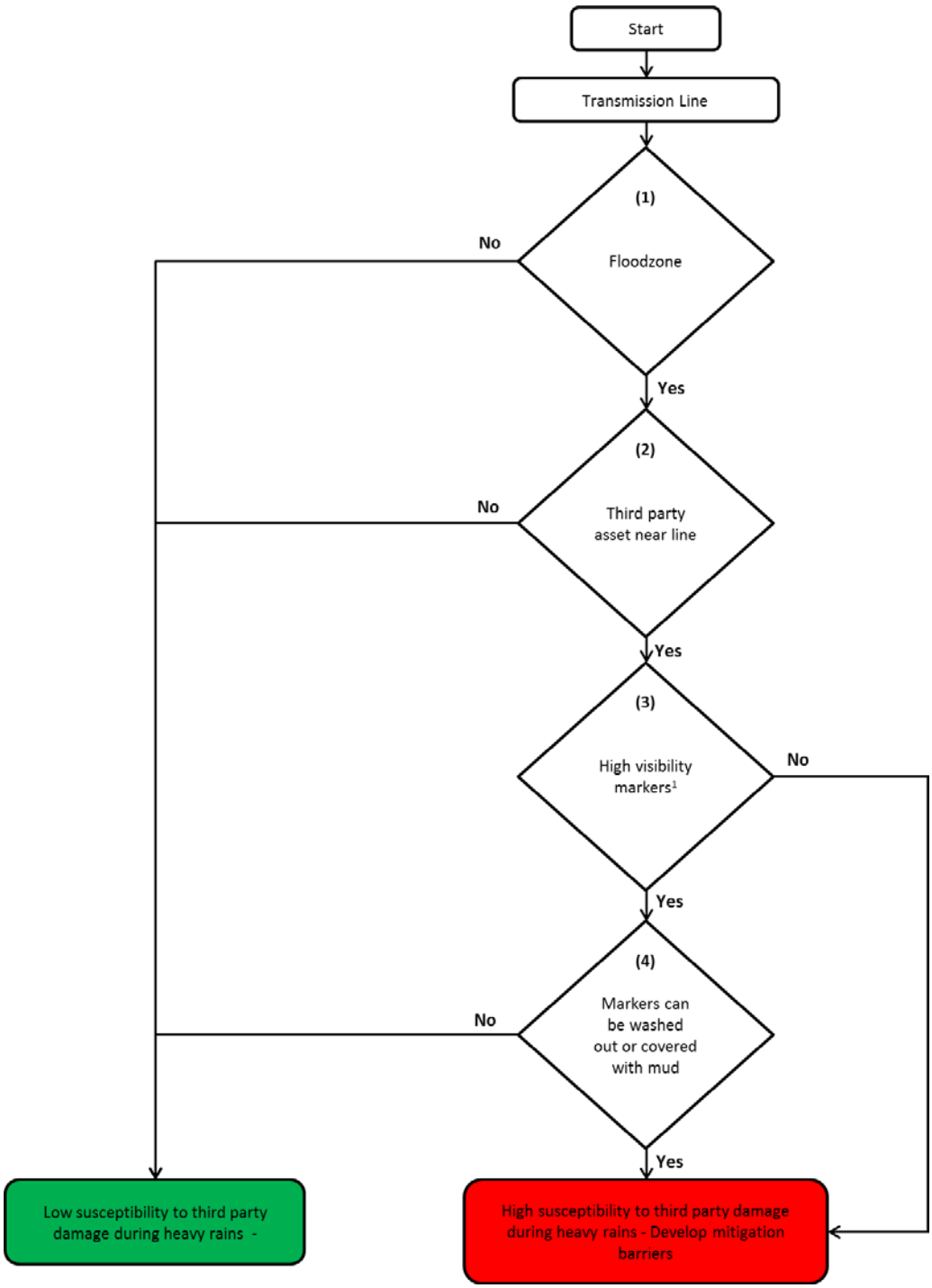
Figure 24. Flowchart for TP + HRF Interacting Threat Identification (Offshore)

The data needed to perform this assessment consists of information that may belong to third parties, and therefore might require coordination from an overseeing organization such as API. The review requires defining the pipeline corridor with the help of alignment sheets and/or GIS mapping tool. It also requires assessing the metaocean data affecting the area using the reference data in API 2MET or from a site-specific study. It then requires making an inventory of all floating vessels and jack up platforms upstream in the major surge directions. Gulf of Mexico (GOM) infrastructure maps [21] and fact sheets [22] are available on line. The assessment would then require review of the hurricane preparedness plan for each vessel and the platform structural integrity assessment. Most of those assets would not be owned by the pipeline operator, and it is highly improbable that the all third party asset information would be made available.

Hurricane preparedness being a major concern for the offshore oil industry, the API is coordinating the efforts to evaluate the preparation measures of all operators in the Gulf of Mexico. The API Structure Integrity Management initiative is an ongoing process for ensuring the continuing fitness-for–purpose of the GOM structures. One of the purposes of this initiative is to implement a managed system for the archival and retrieval of SIM data and other pertinent records [23]. This particular case requires that the API RP 2SIM database is made available.

Third Party Damage + Heavy Rain or Floods (TP + HRF) - Onshore

This section presents the second scenario for TP + HRF incidents. The system considered is a buried transmission line in an area affected by heavy rains or flooding. In contrast with TP + IO, there is no intervention of the operator during the sequence of events. Figure 25 presents the flowchart for TP + HRF interacting threat identification (Onshore).



(1) Can markers be read under low light conditions?

Figure 25. Flowchart for TP + HRF Interacting Threat Identification (Onshore)

The assessment requires identifying third party assets near the pipeline and in a flood zone. Flood zones are generally identified in alignment sheets and/or GIS mapping tools. Third party utility lines are often identified in the alignment sheets, and their ROW should be clearly marked. Agricultural assets maybe somewhat difficult to identify, but the encroachment reports and the definitions of class locations and HCAs can be a useful resource. The assessment requires assessing if the markers can be washed out or covered by mud during a storm or flood; this requires reviewing the patrolling/survey reports.

The ROW markers and any physical protection of the line are physical barriers that are intended to reduce impacts from third parties. Every pipeline awareness program should have a reach out component, which maintains contact with other utility companies and the public.

Stress Corrosion Cracking and Previously Damaged Pipe (SCC + PDP) Interacting Threat Identification

Only one incident with this interactive threat was found in the DOT database of reportable incidents, but five investigations conducted by Kiefner identified this interaction to be the cause of failures. The narrative of the one incident reported to DOT stated that the leaking section of the pipe had been sent to a lab for metallurgical analysis. The leak occurred at a longitudinally oriented gouge within a dent and incidental stress corrosion cracking was observed in the gouge. It was concluded that the dent increased the local stresses. The Kiefner investigations reported that the deformations were sufficient to damage or disbond the coating, and the cathodic protection was inadequate in some way. The increased residual stress associated with the dent can be sufficient to initiate and grow SCC in these locations.

Stress Corrosion Cracking is a complex mechanism that is being studied, some factors affecting SCC are:

- Applied tensile stress (the sum of pressure-induced stress and any residual stress in the material whether present from manufacturing for from the deformation associated with a dent)
- Susceptible material (all common line pipe is thought to be susceptible)
- Exposure to a soil/ground-water environment because of missing or disbonded coating
- The level of cathodic protection effectiveness
- Type of coating

The flowchart for SCC + PDP interacting threat identification presented in Figure 26 does not assess the above factors, but rather checks for evidence of dents and stress corrosion cracking on the line.

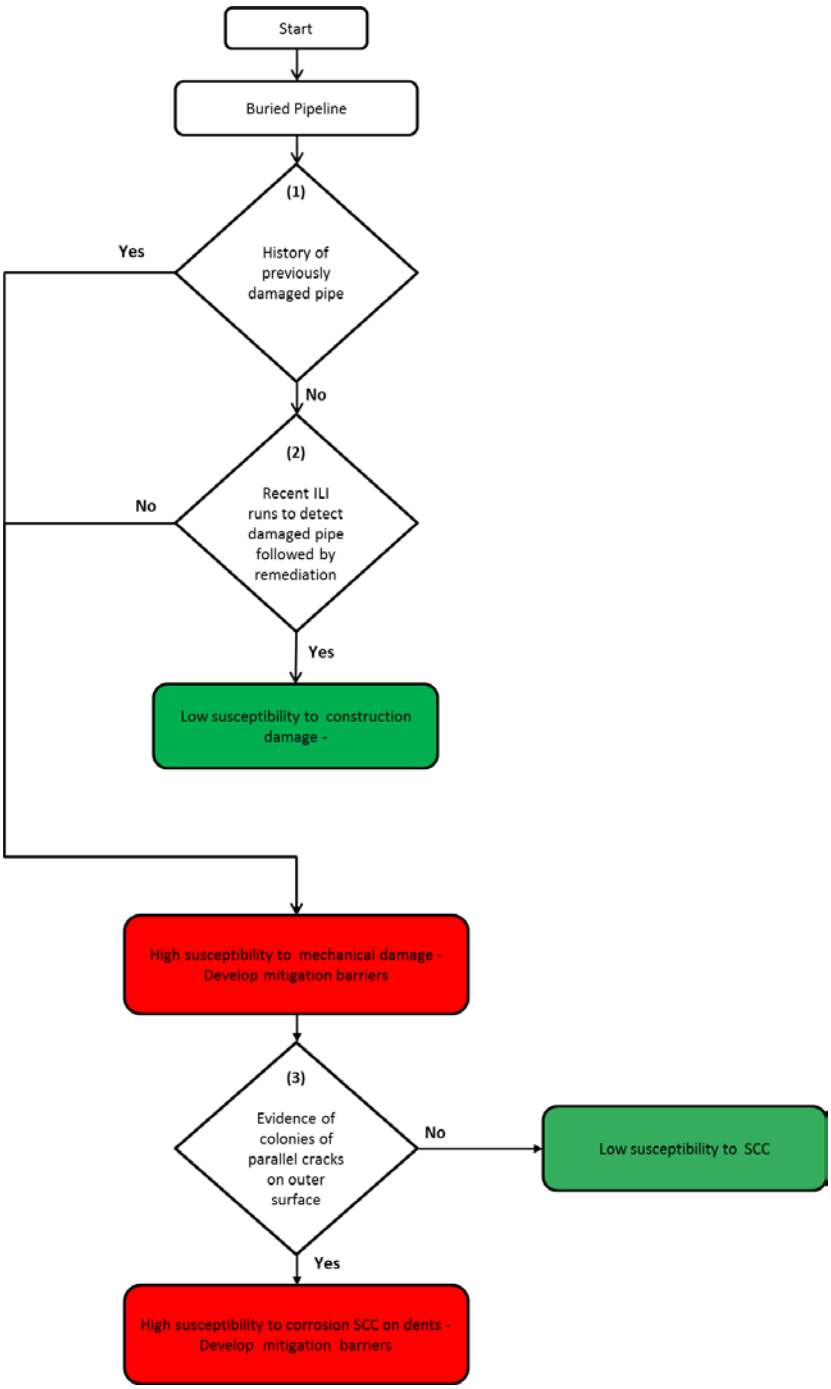


Figure 26. Flowchart for SCC + PDP Interacting Threat Identification

The methodology proposed in API 1176 1st Ed. (2016) to manage the potential threats posed by the presence of cracks in a pipeline applies for the SCC cracking in dents scenario (see the EC + DPS or IC + DPS assessment). The recommended practice proposes gathering, reviewing and integrating the available information regarding the pipeline design, the pipeline attributes, its operational history and any results of prior inspections. The operator needs to review any available encroachment reports, direct assessments and ITD reports to assess if there is evidence of PDP sites along the line. In addition, the assessment requires reviewing any geometry and metal loss ILI tool reports for evidence of dents, followed by a review of the ITD inspection reports for evidence of SCC cracks colonies. Emerging ILI technologies are capable of detecting cracks on dents features but this is not considered in the identification flowchart (see following section for further discussion).

SCC in dents can be detected using a combination of direct and indirect methods:

- DCVG or ACVG to locate damaged or disbonded coating
- ILI using geometry and metal loss tools to locate PDP (Crack tool is not necessary as long as objective is to address the SCC+PDP interactive threat)
- ITD Visual inspection to detect evidence of SCC
- ITD validation and characterization of PDP indications

In addition, in-line inspection can be used to detect and assess the cracks on dents features. A dent with any indication of metal loss, cracking or stress riser must be classified as an immediate condition per ASME B31.8S, however, it is particularly difficult to quality check cracks on dents indications from ILI tools. The analysis for EC + DPS presented three ILI technologies suitable for crack detection; some EMAT tools might be suitable to distinguish a dent with cracking feature with the adequate sensor configuration. The signal post-processing requires decoupling the high and low magnetization components of the signal to enhance the residual magnetization at any stress concentrators in the dent or in its vicinity [24].

The encroachment prevention plan is the principal barrier in place to reduce the likelihood of future PDP. Hydrostatic testing has limited impact because only areas of PDP that fail will be detected.

Other Threat Interactions

It is recalled that there are 190 possible interactions of any two of the 20 industry-recognized threats. Of the 190 possible interactions, no reportable incidents were discovered for 90 interactions, 1 to 8 reportable incidents were discovered for 77 interactions, and 10 or more reportable incidents were discovered for 23 interactions. The latter 23 plus one other interaction were addressed in the preceding flowcharts. Do operators need to consider any of the 166 interactions not addressed in the flowcharts? For the 90 interactions for which no

reportable incidents were discovered, the answer is probably no. Many of these 90 seem intuitively unlikely. Regarding the other 76 interactions for which 1 to 8 incidents were discovered, operators may want to consider them, but experience in terms of the number of incidents suggests that they are less important than the 24 types covered by the flowcharts.

For the record the other incidents (other than the 24 covered by the flowcharts) are listed below in Table 7 and Table 8.

Table 7. Ninety Possible Threat Interactions for Which No Reportable Incidents Were Discovered

1	EC+SPPF	31	DP+PDP	61	CD+TP
2	EC+TP	32	DP+V	62	CD+PDP
3	EC+V	33	DP+HRF	63	CD+V
4	EC+LIGHT	34	DP+LIGHT	64	CD+LIGHT
5	IC+SCC	35	DPS+DFW	65	MCRE+PDP
6	IC+DP	36	DPS+DGW	66	MCRE+V
7	IC+CD	37	DPS+TSBPC	67	TSBPC+SPPF
8	IC+SPPF	38	DPS+GF	68	TSBPC+PDP
9	IC+TP	39	DPS+SPPF	69	TSBPC+V
10	IC+PDP	40	DPS+TP	70	GF+SPPF
11	IC+V	41	DPS+PDP	71	GF+PDP
12	IC+EM	42	DPS+V	72	SPPF+TP
13	IC+HRF	43	DPS+HRF	73	SPPF+PDP
14	IC+LIGHT	44	DPS+LIGHT	74	SPPF+V
15	IC+CW	45	DPS+CW	75	SPPF+EM
16	SCC+MCRE	46	DFW+CD	76	SPPF+HRF
17	SCC+TSBPC	47	DFW+MCRE	77	IO+V
18	SCC+GF	48	DFW+GF	78	TP+V
19	SCC+SPPF	49	DFW+SPPF	79	TP+LIGHT
20	SCC+TP	50	DFW+V	80	TP+CW
21	SCC+V	51	DFW+LIGHT	81	PDP+V
22	SCC+HRF	52	DGW+TSBPC	82	PDP+LIGHT
23	SCC+LIGHT	53	DGW+GF	83	PDP+CW
24	SCC+CW	54	DGW+SPPF	84	V+EM
25	DP+DFW	55	DGW+PDP	85	V+HRF
26	DP+DGW	56	DGW+V	86	V+LIGHT
27	DP+TSBPC	57	DGW+LIGHT	87	V+CW
28	DP+GF	58	CD+MCRE	88	EM+LIGHT
29	DP+SPPF	59	CD+GF	89	HRF+LIGHT
30	DP+TP	60	CD+SPPF	90	LIGHT+CW

Table 8. Seventy-six Threat Interactions for Which 1 to 8 Reportable Incidents Were Discovered

	Type of Interaction	Number of Incidents		Type of Interaction	Number of Incidents
1	EC+DP	1	39	DFW+HRF	2
2	IC+GF	1	40	DFW+CW	2
3	SCC+DP	1	41	DGW+TP	2
4	SCC+DGW	1	42	MCRE+SPPF	2
5	SCC+CD	1	43	TSBPC+GF	2
6	SCC+EM	1	44	GF+TP	2
7	DP+DPS	1	45	GF+LIGHT	2
8	DP+MCRE	1	46	GF+CW	2
9	DP+CW	1	47	IO+EM	2
10	DFW+DGW	1	48	TP+PDP	2
11	DFW+PDP	1	49	PDP+HRF	2
12	DGW+CD	1	50	EM+CW	2
13	DGW+MCRE	1	51	EC+HRF	3
14	CD+IO	1	52	IC+TSBPC	3
15	CD+HRF	1	53	IC+IO	3
16	MCRE+EM	1	54	DFW+TP	3
17	TSBPC+LIGHT	1	55	DGW+CW	3
18	GF+V	1	56	CD+TSBPC	3
19	GF+EM	1	57	GF+HRF	3
20	SPPF+LIGHT	1	58	HRF+CW	3
21	SPPF+CW	1	59	EC+DFW	4
22	IO+LIGHT	1	60	IC+MCRE	4
23	PDP+EM	1	61	CD+CW	4
24	EC+IC	2	62	TP+EM	4
25	EC+SCC	2	63	EC+TSBPC	5
26	EC+GF	2	64	DP+IO	5
27	EC+EM	2	65	MCRE+TSBPC	5
28	EC+CW	2	66	MCRE+GF	5
29	IC+DFW	2	67	MCRE+TP	5
30	SCC+DPS	2	68	MCRE+HRF	5
31	SCC+DFW	2	69	IO+HRF	5
32	SCC+IO	2	70	DFW+EM	6
33	DP+CD	2	71	DGW+IO	6
34	DP+EM	2	72	EC+MCRE	7
35	DPS+CD	2	73	CD+EM	7
36	DPS+MCRE	2	74	SPPF+IO	7
37	DPS+EM	2	75	MCRE+LIGHT	8
38	DFW+TSBPC	2	76	IO+PDP	8

ANALYSIS METHODS FOR PRACTICAL GUIDANCE

Several appendices to this report are presented to assist operators by providing analysis techniques for assessing the effects of some of the interacting threats. The relevant appendices are as follows.

- Appendix C – Pipeline Strain Analysis in Biaxial Loading
- Appendix D - Cyclic Loading Criteria
- Appendix E - Monotonic Increasing Loads Criteria
- Appendix F – Failure Assessment Diagram
- Appendix G - Misalignment of Girth Weld Stress Concentration Factor
- Appendix H - Stress Intensity Factor and Limit Load Solution for Branch Junction
- Appendix I - Stress Intensity Factor and Limit Load Solution for Pipe Bends and Elbows
- Appendix J - Criteria for Freeze Rupture of Operational Deadlegs
- Appendix K - Incorporating Interactive Threats into Relative Risk Ranking Algorithms

The section for biaxial loading presents a strain analysis corresponding to a pipeline displacement resulting in a system with bending and elongating components. The method for pipeline displacement prediction due to earth movement is often coupled with the biaxial loading strain analysis. However, the pipe-soil interacting analysis is not considered part of the fitness-for-service analysis of a pipeline subjected to external loading, since it is used for predictive analysis. The methodology for implementing such analysis is well-established and described in available in industry guidance documents [25, 26].

The focus of the biaxial loading analysis is an algorithm to deduce pipeline strain from an abrupt lateral displacement (such as a landslide). A simplified pipe strain analysis, similar to that presented herein but without considering the operational strain, has been presented and validated for PRCI [27]. The pipeline strain analysis presented in Appendix C considers all components for completeness. The strain analysis is followed by some considerations on how to incorporate pipeline displacement data from ILI geometric tools or ITD examination.

Appendix D presents the criteria for cyclic loading. The first part of Appendix D introduces the equations for S-N crack initiation curves and the Paris law for fatigue crack growth analysis of planar imperfections. Appendix D also includes methods for fatigue analysis for blunt metal loss[13] and crack like defects.

[13] Such as corrosion.

Appendix E presents the non-static external loading evaluation methods for increasing monotonic loading criteria. A pipe that is subjected to a surface loading will experience ovalization and longitudinal bending which induce hoop and longitudinal stresses in the pipe in addition to those from internal pressure. These stresses can be estimated using the Canadian Energy Pipeline Association (CEPA) solution and beam on elastic foundation theory. The CEPA equation estimates the membrane stress and through-thickness (local) bending stress in the hoop and longitudinal directions from a surface load. The equation accounts for the soil overburden pressure as well as the effect of internal pressure and soil resistance.

Appendix F presents methods for predicting failure stress levels of crack-like defects. The analysis for crack like defects requires the use of the Failure Assessment Diagrams (FAD). The user can determine if a crack like defect is acceptable. Stress intensity factor equations are presented for (axially oriented) metal loss defects and gouges/cracks. The axially oriented defects stress intensity factor derivation and FAD method are briefly explained in Appendix F.

Appendix G presents the stress concentration factors for an eccentric girth weld. The equations of this subsection can be applied to girth weld misalignment due to construction tolerance, pipe thickness tolerance and pipe out-of-roundness. The assessment of an imperfection at a girth weld can be performed similar to that of the base metal using intensified stresses as long as representative material properties are used.

Appendix H contains the stress concentration factors and crack stress intensity factors for tee-connections. The stress concentration factors are for internal pressure, in-plane bending moments acting on the branch, and bending moments applied to the run.

Appendix I presents the stress concentration factors for elbows and pipe bends under internal pressures, axial force and in-plane bending. Crack stress intensity for an elbow or a pipe bend is calculated similarly to that of a straight pipe (see Appendix F).

The incidents occurring in changing environments are discussed in the aggravated threats discussion. In addition, Appendix J presents the basis for a criterion for assessing the potential for freeze rupture of operational deadlegs.

Appendix K presents an example, using the EC + DPS interacting threat, of how one might estimate the increased likelihood of failure, if there is interaction, over the likelihood of failure from either EC or DPS alone. The method depends on isolating the number of incidents of each type found in the database of reportable incidents. The example shows that the number of EC+DPS incidents plus the number of EC incident is 13% higher than the number of EC incidents alone. Such a calculation could be of use to a pipeline operator in allocating resources for integrity management.

APPENDIX A - LITERATURE REVIEW

API 1160

API 1160 [28] explicitly discusses the interaction of threats only in the scenario-based model of risk assessment. Interacting threats that are known to cause failures were added as a stand-alone threat namely selective seam corrosion and anomaly growth by pressure-induced-fatigue. API 1160 implicitly points out a number of interactions of threats by recommending specific considerations and giving cautionary notes through the discussion of individual threats in Annex A. Table A-1 lists the cases of interacting threats highlighted in API 1160 with brief description of each case.

Table A-1. Threat Interaction Cases in API 1160

No.	Threat # 1	Threat # 2	Interaction description	Loading Condition
P1	Internal or external corrosion	Pipe seam defect	Selective seam weld corrosion (SSWC) is the interaction of internal or external corrosion with pipe seam defect, in terms of low toughness properties along the pipe ERW seam weld. A number of pipeline failures have occurred as rupture even at very low stresses due to this threat [29].	Time-varying environments
P2	External corrosion	Manufacturing related defect	Narrow axial external corrosion (NAEC) is found at double submerged arc welding seams coated with polyethylene type. The "tenting" of the coating over the weld crown allows water intrusion and at the same time shields the cathodic protection[14]. The resulting axially-oriented groove-like defect is more likely to rupture than leak.	Time-varying environments
P3	External corrosion	Previously damaged pipe	The pipe might be dented by rock which at the same time might shield the cathodic protection. In this case, corrosion may occur even when pipe-to-soil potential measurements suggest adequate protection and enhanced inspections or mitigative measures are recommended.	Time-varying environments
P4	Internal corrosion	Pipe defect	The acidic reaction of internal corrosion of pipelines transporting sour crude oil produces atomic hydrogen diffuse into the pipe body. Hydrogen gas is forms if the atoms encounter and collect in pipe laminations. Pipe laminations are normally harmless; however, they are potential to become blisters and develop cracks with the accumulation of hydrogen which threatens the pipe integrity.	Time-varying environments

[14] While API 1160, ASME B31.8s and other industry practices list only pipe metallic body defects and pipe seam defects as manufacturing defects, a recent PRCI project [79] lists defective coating/coating applications under manufacturing-related defects.

No.	Threat # 1	Threat # 2	Interaction description	Loading Condition
P5	Manufacturing related defect	Anomaly growth by pressure-induced fatigue (including transit fatigue).	The initial non-injurious anomaly might grow under the pressure-cycle threat to an injurious level. The pressure cycles are more aggressive in liquid pipelines than gas pipelines and many failures have been reported. Transit fatigue is a crack growth that occurs during the line pipe transportation.	Cyclical load
P6	Construction related defect			Cyclical load
P7	Third party damage			Cyclical load
P8	Stress Corrosion Cracking (SSC)	Previously damaged pipe	Stress level is one of the conditions that must be present for SCC to occur. While the global hoop or axial stress in the pipe may be below the stress level threshold, conductive stress levels imposed by deformation due to rock dents might be of high enough value for SCC to occur.	Time-varying environments
P9	Stress Corrosion Cracking (SSC)	Anomaly growth by cyclic loading	SSC often from and continue to grow without the need of cyclic load. However, some amount of stress cycling can promote the growth by breaking the oxide film in the crack and re-exposing it to the environment. If appreciable amount of cyclic loading is present, the crack will grow by structural load in addition to the growth by the environment.	Time-varying environments+ Cyclical load
P10	External corrosion	Pipe defect (Hard Spots or Hard Heat-affected Zones)	The corrosion itself does not interact with the pipe hard microstructure. However, the cathodic reaction in the presence of hydrogen sulfide and water can allow atomic hydrogen to diffuse into the steel. This may lead to hydrogen cracking in microstructure with hardness higher than Rockwell C22. These hard spots may exist in the pipe body or more probably in the seam heat affected, especially with vintage ERW pipes, due to fast cooling rate.	Time-varying environments
P11	Construction related defects	Weather related and outside force	Electric arc girth welds even with flaws rarely cause a pipeline to fail unless they are subjected to extreme axial loads resulting from a landslide or a washout. An obsolete acetylene girth weld might fail under marginal increase of axial load, and therefore, the operator should monitor the pipe movement rigorously. Similarly, soil movement should be monitored if intentional wrinkle bends exist in a pipeline.	Monotonic increasing load

ASME B31.8S

ASME B31.8S [30] states that the interactive nature of threats shall be considered when identifying the potential threats to the integrity of gas pipelines. A limited number of interaction cases are presented as examples to alert the user of the Code. The first example is corrosion at a location that also has third party damage. The other example is the shielding of cathodic protection in rocky terrain which will make protection of the damaged coating section ineffective or insufficient. The third example is the accelerated corrosion at certain seam types. For addressing the pipeline construction defect integrity threat, the Code recommends gathering data about the potential for the threats of outside forces and significant pressure cycling and fatigue being present. All interaction cases discussed in ASME B31.8S are summarized in Table A-2 while keeping the same case number as Table A-1 if the interaction case was already discussed.

Table A-2. Threat Interaction Cases in ASME B31.8S

No.	Threat # 1	Threat # 2	Interaction description	Loading conditions
P1	Internal or external corrosion	Pipe seam defect	See Table A-1	Time-varying environments
P3	External corrosion	Previously damaged pipe	See Table A-1	Time-varying environments
P5	Construction related defect	Anomaly growth by pressure-induced fatigue (including transit fatigue).	See Table A-1	Cyclical load
P11	Construction related defects	Weather related and outside force	See Table A-1	Monotonic increasing load

CSA Z662

CSA Z662 [2] requires that the hazard identification take into consideration the primary failure causes and any additional failure or damage from incident causes that are relevant. Though the three categories given by the code for hazard identification should be able to identify threat interaction, the third category which uses “a logical pathway to translate different release or initiating events into possible outcomes, such as event tree analysis and fault tree analysis” might be the most successful in identifying interaction of threats. The Code does not discuss any examples of interaction of threats or failure causes.

DNV-RP-F116

DNV-RP-F116 [1] states that the combined effects of a threat should be considered. In order to achieve this, the Code provides a guidance note that recommends conducting an initial risk assessment for all potential failure mechanisms and possible “sub mechanisms” followed by a

full risk assessment for threats relevant to the actual pipeline. The standard highlights that a primary damage from a threat can develop into a secondary damage that creates another threat. It gives the example of a third party threat creating damage in the coating which leads to an external corrosion threat that might develop into metal loss anomaly.

Pipeline Defect Assessment Manual (PDAM)

The Pipeline Defect Assessment Manual (PDAM) [31] is an integrity assessment document rather than an integrity management document. However, it discusses the factors, or threats, that affect integrity of pipe by either creating a defect in the pipe or changing the applied loads. Complex load combinations of pressure, axial, and bending both static and cyclic are presented in the document for various pipe defects.

Table A-3 extracts the threat interaction that can lead to such complex load.

Table A-3. Threat Interaction Cases in PDAM

No.	Threat # 1	Threat # 2	Interaction description	Loading conditions
P12	Internal or external corrosion	Weather related and outside force (earth movement)	Pressure is the main load that affects the integrity of corroded pipes. However, high longitudinal compressive stresses exceeding yielding such as the ones resulting from ground movement might decrease pressure capacity of the corroded pipe.	Biaxial load + Monotonic increasing load
P13	Internal or external corrosion (circumferential)	Weather related and outside force (earth movement)	While not very common, if the corrosion is oriented in the circumferential directions, high axial loads such as the ones resulting from earth movement might cause failure.	Monotonic increasing load
P14	Previously damaged pipe	Weather related and outside force (earth movement)	Bending loads in addition to the pressure affects the integrity of mechanically damaged pipe. An increase in the axial loads due earth movement might increase the likelihood of failure.	Monotonic increasing load
P15	Previously damaged pipe	Incorrect Operations (procedure)	Bending loads in addition to the pressure affects the integrity of mechanically damaged pipe. The pipeline operator might not consider the impact of the bending loads due to the lack of industry agreed on procedure.	Biaxial loading
P16	Previously damaged pipe	Incorrect Operations (procedure)	As discussed in P16, bending load affects the integrity of the mechanically-damaged pipe. The integrity will be further impacted if the bending load is cyclic due to thermal stresses or vibration for example.	Biaxial loading + cyclical bending
P17	Manufacturing defect	Weather related and outside force (earth movement)	Pressure is the main load that affects the integrity of pipes with manufacturing defects (pipe or seam). However, high longitudinal compressive stresses exceeding yielding such as the ones resulting from ground movement might decrease pressure capacity of the defected pipe.	Biaxial loading + monotonic increasing load
P18	Manufacturing defect	Weather related and outside force (cold weather)	The toughness of the pipe has an impact of the pressure capacity of defected pipe segments. Severe cold weather might reduce the pipe toughness significantly causing a defected pipe to fail.	Time-varying environment
P19	Manufacturing defect	Construction (new weld to near defect)	The material properties of the pipe have an impact of the pressure capacity of defected pipe segments. New welding activities for repair, hot or cold-tap, etc. near a defect might locally change the material properties causing a defected pipe to fail.	Time-varying environment

PPTS Advisory 2009-5

The PPTS advisory 2009-5 [32] was specifically for liquids and did not address threats explicitly as API 1160 and ASME B31.8S. Rather it focused on previously known areas of failure (tubing/small piping, drain lines, dead legs, relief lines, valve vaults and inspection practices) and tried to make conclusions and recommendations based on the survey of operators. However, through the discussion given in the advisory, the interaction cases presented in Table A-4 can be inferred.

Table A-4. Threat Interaction Cases in Liquid Piping Facilities

No.	Threat # 1	Threat # 2	Interaction description	Loading conditions
F1	Construction related	Incorrect operations (design error)	Improper installation of the small tubing and small piping is the major cause of release incidents in facilities. Most small size pipe and tubing are quick installation, but the manufacturer recommendations are not followed. The survey showed that vibration a major contributing factor to the failure. Vibration is likely because of improperly designing the piping/support system. It was also noted that two-third of the failure involved fitting not the pipe itself. This is an indication of excessive loading other than the pressure due to improper design of the piping layout.	Cyclical loading, Biaxial loading, or a combination
F2	Internal corrosion	Incorrect operations (design error, flushing procedure)	Internal corrosion is a major threat in facilities especially in tubing and small piping, dead legs, drain lines and relief lines, and particularly for crude operations. The problem might be aggravated by not having a proper design of piping layout that avoids pocketing, minimizing dead legs and providing slope for drain lines. Also, the operational procedure of flushing once a year is not enough and its frequency should be increased based on the facility specific conditions.	Time-varying environment
F3	Cold weather	Incorrect operations (design error)	Water expands in freezing conditions and might break its containment. Therefore, water accumulation should be mitigated by avoiding potential water traps during the design of drain piping layout.	Time-varying environment
F4	Internal corrosion	Incorrect operations (inspection activities)	Operators participating in the survey did not follow one standard for inspection activities. With the presence of other threats such as internal corrosion, releases are possible as the pipe segments most potential to release product were not identified.	Time-varying environment

Integrity Management for Specific Threats

Specific threats have received more attention either due to their frequency and consequences of occurrence like pipe seam defects in low frequency ERW pipes, due to their complicated nature such as SSC, or if they cannot be avoided such as ground displacement in some areas. This additional attention was in the form of focused research and studies on these specific threats which includes identifying all factors that contribute to the specific threat.

Stress Corrosion Cracking

Several studies and best practices about stress corrosion cracking are available in public domain [33] [34] [35] [36]. As SCC needs specific conditions of material, environment, and stress level to occur, it is possible that other pipeline threats will change one of these conditions to either initiate or aggravate SCC. The interaction cases discussed in references [33] [34] [35] [36] are presented in Table A-5.

Table A-5. Threat Interaction Cases with Stress Corrosion Cracking

No.	Threat # 1	Threat # 2	Interaction description	Loading conditions
P8	SCC	Previously Damaged Pipe	In addition to the factor of higher localized stress associate with the dent as discussed in A-1, reference [35] highlights that rock dents may damage the coating, shield the CP which result in an environment that are conductive to SCC initiation and growth.	Time-varying environments
P20	SCC	Incorrect Operations (Unmonitored Cyclic Pressure/groundwater pH/temperature)	The threshold stress for SCC initiation and growth might reduce significantly if the pipeline is subjected to cyclic pressure fluctuations. The cyclic pressure fluctuations may cause cyclic softening, i.e. locally lowering the yield strength of the pipeline. The operator should also monitor, and control when possible, the ground water pH and pipeline temperature. [36]	Time-varying environments+ cyclical loading
P21	SCC (circumferential)	Weather related and outside force (geotechnical)	While the pipe might have the material and environment susceptible to SCC, tensile axial stresses are normally below the threshold to initiate SCC. The threat of geotechnical instability and land movement may increase the axial stresses to a level that can initiate circumferential SSC cracks. [34]	Time-varying environments
P22	SCC	Incorrect Operations (CP procedures)	The high pH SCC initiation and growth is a function of the amount of CP current that passes through the soil. Higher than needed current will increase the SCC growth unnecessarily. Moreover, it might cause coating disbondment and create new location susceptible to SCC. [36]	Time-varying environments
P23	SCC	Manufacturing related or Construction related (tensile residual stresses)	Tensile residual stresses are not a threat to the integrity of pipelines by themselves, and this is why they are not listed in Table A-1. However, these stresses that develop during the manufacturing or construction of the pipeline can have high enough level to lead to SCC cracks where the global stress in the pipe will not. [36]	Time-varying environments

Manufacturing Related-Pipe Seam Defect

There are several pipe seam defects associated with the manufacturing of the pipe seam. Of main interest are ERW and lap welded seams as they have categorically exhibited increased tendencies for failures. Such defects include hook cracks, cold welds, and stitching which may interact with other threats such as corrosion and pressure-induced fatigue. A significant number of piping failures in service and during hydrotesting is caused by these pipe seam defects; 280 failure cases were analyzed by Kiefner [37]. Some pre-regulated pipelines and pipelines installed before March 12, 1970, have higher likelihood of failure as their integrity cannot be assured by previous pressure tests or ILI pigging [38]. Table A-6 summarizes the interaction cases discussed in references [37] [38] [39] [40].

Table A-6. Threat Interaction Cases with Pipe Seam Defect

No.	Threat # 1	Threat # 2	Interaction description	Loading conditions
P1	Pipe seam defect	Internal or external corrosion	See Table A-1. Selective seam corrosion is discussed in [37] and [38]. Due to the increased concern with this type of interaction as it was reported to cause rupture at very low stresses [29], a focused research program was initiated to better understand its characteristics [40].	Time-varying environments
P5	Pipe seam defect (Crack + low toughness)	Crack growth by pressure-induced-fatigue	This interaction is similar to P5 discussed in Table A-1. However, some vintage low frequency ERW seams have low toughness values that make the crack failing at normal operating pressure less than expected and thus reducing the fatigue life considerably.	Cyclical load
P10	Pipe seam defect (hook crack + hard spot)	External corrosion or internal corrosion (hydrogen induced cracking)	See Table A-1.	Time-varying environments
P24	Pipe seam defect (hook crack)	SSC	Three out of 280 failure cases studied by Kiefner [37] involved the interaction of hook crack and SSC. In one case, the hook crack was the initiation point of the SSC, and in the other two, they coalesced after the SCC growth. In all cases, the localized higher stress due to the presence of the hook crack might be a contributing factor to SSC initiation.	Time-varying environments
P25	Pipe seam defect	Incorrect operations (pipes without pressure test) + pressure-induced fatigue	As large pipe seam defects could be resident in untested pipe segments making the time required to for the defect to fail at the operating pressure much shorted than expected. This was the reason of the only reported failure in gas lines due to pressure cycle [38].	Cyclical load

Construction Related Defects

Construction defects are categorized as stable and, therefore, will not fail unless they interact with another threat. The interacting threat must change the magnitude and/or the frequency of the applied loads to cause construction defects to fail.

Table A-7 summarizes the interaction cases discussed in references [41] [42] [43] [44].

Table A-7. Threat Interaction Cases with Construction Threats

No.	Threat # 1	Threat # 2	Interaction description	Loading conditions
P11	Construction related (defective girth weld or wrinkle bends)	Weather related and outside force	See Table A-1.	Monotonic increasing load
P26	Construction related (defective girth weld)	Incorrect Operations (Design error)	Defective girth welds have half the fatigue life of sound girth welds when subjected to cyclic axial bending stresses [44]. Excessive vibrations can occur in poorly designed above-ground pipelines due to internal or external fluctuating fluid forces such as wind-induced vibrations [44]. High thermal stress range due to lack of piping flexibility or unusual temperature change will also cause defective girth welds to fail in a shorted than expected time [43].	Biaxial load+Cyclical load
P27	Construction related (wrinkle bends)	Pressure-induced fatigue	The long-term integrity of wrinkle bends subjected to cyclic-pressure is a concern although no failure has been reported. Reference [43] presents a method to rank the relative severity of wrinkle bends under such conditions.	Cyclical load
P28	Construction related (wrinkle bends)	Pressure-induced fatigue + External corrosion	Metal loss in wrinkle bends has been called by ILI tools. There was a concern by pipeline operators that the metal loss might increase the stress concentration factor at the wrinkle bends and reduce fatigue life if the pipe is subjected to cyclic pressure. While reference [42] provided a framework to evaluate such interaction case, it stated that no known incident of such nature have been identified by the subject matter experts consulted during that research work.	Cyclical load

Weather Related and Outside Forces

References [25] and [45] are dedicated for the integrity management of ground movement hazards. The references give comprehensive details to identify and mitigate this threat which could increase the risk of failure when certain incorrect operations are in effect. Another threat which is not covered by the general integrity management practices, and therefore subject to incorrect operations, is the cyclic outside forces due to blasting, mining, driving pile [46] or railroad crossings. This type of interaction is presented in Table A-8.

Table A-8. Threat Interaction Cases with Ground Movement

No.	Threat # 1	Threat # 2	Interaction description	Loading conditions
P29	Weather related and outside force (Earth Movement)	Incorrect Operations	Failure to follow the mitigation methods will increase the likelihood of failure due to ground movement. The mitigation may be taken during design stage to increase the capacity of the pipeline to ground movement loads or during operation stage by closely monitoring ground movements. [25]	Monotonic increasing load
P30	Weather related and outside force (cyclic)	Incorrect Operations	API 1160 does not address outside force that impose cyclic stresses. ASME B13.8s only discusses seismic. Blasting driving pile and mining all develop cyclic stresses. Lack of discussion might be missed, and no procedure available to assess the risk. [46]. Another outside load that is cyclic in nature is the rail road crossing is cyclic.	Cyclical loading

Internal or External Corrosion

Internal or external corrosion is a major threat and exists on almost all pipelines therefore, interaction with other threats is highly possible. This explains why it occurred in nearly one-third (11 out of 35) of the pipeline interacting cases and one-half (2 out of 4) facility interacting cases discussed previously. Corrosion integrity management and assessment is still an active area of research that addresses new challenges which can be discovered by ILI even if they have not caused failures before. Table A-9 summarizes two interacting cases with corrosion that are worth consideration.

Table A-9. Additional Threat Interaction Cases with Corrosion

No.	Threat # 1	Threat # 2	Interaction description	Loads
P31	Internal or external corrosion	Pressure-induced-fatigue	Theoretically, corrosion may affect the fatigue life of pipe by considerably eliminating crack initiation period, increasing fatigue crack growth rate, and increasing the cyclic stress range [47]. However, as the reference comparison is to a defect-free pipe, even the reduced fatigue life might still be considerably longer than the most aged pipelines which explain the lack of real case failures.	Cyclical pressure loading
P32	Internal or external corrosion	SCC	Significant metal loss more than 10% of the wall and cracks are not commonly found together. However, reference [48] reports that recently these hybrid defects including cracking within corrosion (Cracking In Corrosion - CIC) have been identified. The explanation is that significant metal loss will increase the localized stress within its area which may reach the threshold of SSC initiation.	Time-varying environment

APPENDIX B - REVIEW OF DOT REPORTABLE INCIDENT DATA

External Corrosion and Internal Corrosion (EC + IC)

External and internal corrosion can occur at the same location in a pipeline; the causes of the two would be completely unrelated to one another. The fact that they occur in the same location means that the mechanical strength of the pipe is reduced by both phenomenon, but one is not causing the other to occur. There are only two instances of external and internal corrosion interacting in HL lines; one of them being a repair sleeve affected by the internal corrosion that deteriorated the pipeline wall and external galvanic corrosion. Kiefner did not find any case of this interaction in natural gas pipelines.

External Corrosion and Stress Corrosion Cracking (EC + SCC)

Microbially-induced corrosion (MIC) occurs in similar anaerobic conditions as does near-neutral pH stress corrosion cracking (NNpH SCC). Not surprisingly, shallow SCC is sometimes found at sites of MIC. But MIC is an even more aggressive depolarizer than oxygen and simply overwhelms the SCC tending to corrode the cracks faster than they can grow. This interaction accounted for only one case in HL lines and an additional case in GAS lines. However, four cases of EC + DPS interaction in HL lines report some indication of SCC interaction (see Table B-1 below).

External Corrosion and Defective Pipe (EC + DP)

There is a slight risk that the surface quality of pipe skelp will be so poor as to render some coating materials (particularly fusion bonded epoxy) ineffective. However, when this occurs, the initial coating inspection reveals the problem, and it is usually remedied on the spot. Coatings used on older pipelines, such as coal tar (enamel and epoxy), asphalt, wax, and tape, are less sensitive to the surface finish and could function well if applied properly over imperfections on the pipe surface. This interaction accounted for only one case in GAS lines; no instances where found for HL lines.

External Corrosion and Defective Pipe Seams (EC + DPS)

Some older ERW (not necessarily only low frequency) and flash-welded seam materials are susceptible to selective or "grooving" corrosion. This phenomenon can occur when the pipe is undergoing either external or internal corrosion-caused metal loss and the metal loss affects the area of the seam.

This interaction accounted for 32 cases in HL lines (Table B-1) and 14 cases in GAS lines (Table B-2**Error! Reference source not found.**). The vast majority reports selective seam weld corrosion (SSWC) with pinhole features. All cases where the pipe type is reported correspond to ERW seam pipe; except for one case which is mislabeled as seamless pipe.

Table B-1. EC + DPS Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19900040	HL	EC	DPS		Seam failure at pressure less than MOP	
19940079	HL	EC	DPS		Selective seam weld corrosion	
19940215	HL	EC	DPS		External corrosion of longitudinal seam	
19950039	HL	EC	DPS		Selective seam weld corrosion	ERW pipe
19950088	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	
19950150	HL	EC	DPS		Seam failure at pressure less than MOP	
19900152	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	
19900154	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	Flash welded pipe
20000034	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	
20020197	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	LFERW
20030163	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	ERW
20030207	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	HF ERW
20030458	HL	EC	DPS		Selective seam weld corrosion	ERW
20040269	HL	EC	DPS		Selective seam weld corrosion	LF ERW
20050129	HL	EC	DPS		Selective seam weld corrosion	HF ERW
20060193	HL	EC	DPS	SCC		Missing narrative
20060194	HL	EC	DPS	SCC		Missing narrative
20090327	HL	EC	DPS		Selective seam weld corrosion	LF ERW
20110383	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	HF ERW
20120123	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	HF ERW
20120210	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	HF ERW
20120275	HL	EC	DPS	SCC	Pinhole leak - selective seam weld corrosion - SCC	Flash welded pipe
20120284	HL	EC	DPS	SCC	Pinhole leak - selective seam weld corrosion - SCC	HF ERW
20130015	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	
20130018	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	HF ERW
20130136	HL	EC	DPS		Selective seam weld corrosion	LF ERW
20140011	HL	EC	DPS		Selective seam weld corrosion	LF ERW
20150132	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	LF ERW
20150200	HL	EC	DPS		Selective seam weld corrosion	LF ERW
20150210	HL	EC	DPS		Pinhole leak - selective seam weld corrosion	Tagged as seamless!
20150257	HL	EC	DPS		Pinhole leak - selective seam weld corrosion - SCC	LF ERW

Table B-2. EC + DPS Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19860105	Gas	EC	DPS		Selective seam weld corrosion	Flash welded
19900091	Gas	EC	DPS		Selective seam weld corrosion	Flash welded
19900229	Gas	EC	DPS		Selective seam weld corrosion	Flash welded
19920086	Gas	EC	DPS		Selective seam weld corrosion	ERW
19920112	Gas	EC	DPS		Pinhole leak - selective seam weld corrosion	ERW
19930186	Gas	EC	DPS		Selective seam weld corrosion	ERW
19960116	Gas	EC	DPS		General corrosion of seam weld	ERW
20060104	Gas	EC	DPS		Selective seam weld corrosion	Flash welded
20060144	Gas	EC	DPS		Pinhole leak - selective seam weld corrosion	ERW
20070041	Gas	EC	DPS		Selective seam weld corrosion	ERW
20070129	Gas	EC	DPS		Selective seam weld corrosion	ERW
20080001	Gas	EC	DPS		Pinhole leak - selective seam weld corrosion	ERW
20100023	Gas	EC	DPS		Pinhole leak - selective seam weld corrosion	
20130099	Gas	EC	DPS		Selective seam weld corrosion	ERW

External Corrosion and Defective Fabrication Welds (EC + DFW)

There is little evidence to suggest that corrosion and defective fabrication welds interact to create a special threat (see EC + DGW below). However, there are four cases for HL lines that can be attributed at EC + DFW (Table B-3). The narratives suggest preferential corrosion pitting occurred at a weld defect. No such interactions were found for GAS lines.

Table B-3. EC + DFW Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
20040208	HL	EC	DFW	IO	Corrosion pit over sleeve weld defect	Repair
20060232	HL	EC	DFW		Poor quality stopple weld with external corrosion	
20100041	HL	EC	DFW		External corrosion at weld that contained inclusions	
20110009	HL	EC	DFW		Corrosion fatigue over weld with excessive HAZ	

External Corrosion and Defective Girth Welds (EC + DGW)

The girth welding process alters the microstructure of the pipe base metal, resulting in a heat affected zone, and usually involves the deposition of filler metal with a similar but different chemistry than the pipe base metal. Despite these differences in chemical composition and microstructure, no significant inherent susceptibility to internal or external corrosion has been identified. Kiefner has observed instances of corrosion that were apparently more aggressive in the weld heat affected zone and/or deposited weld metal, but these have been isolated cases. Still, this interaction accounted for six incidents in HL lines (Table B-4) and four cases in GAS lines (Table B-5). The majority of these cases are preferential pinhole corrosion over a weld defect.

Table B-4. EC + DGW Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19950167	HL	EC	DGW		Pinhole leak. Improper weld fusion.	
19980110	HL	EC	DGW		Pinhole leak. Arc burning during construction.	Coating holiday.
20020189	HL	EC	DGW		Pinhole leak over fabricated gap.	
20040079	HL	EC	DGW		Pinhole leak over non penetrating girth weld.	
20100003	HL	EC	DGW		Pinhole leak. Arc burning during construction.	
20140005	HL	EC	DGW		Pinhole leak over non penetrating girth weld.	Coating holiday.

Table B-5. EC + DGW Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
20040076	Gas	EC	DGW		Corrosion over defective girth weld	
20040123	Gas	EC	DGW		External corrosion over girth weld with poor quality	
20050078	Gas	EC	DGW		Pinhole corrosion on defective girth weld. Holiday.	Casing
20080038	Gas	EC	DGW		Pinhole corrosion on defective girth weld	

External Corrosion and Construction Damage (EC + CD)

Construction damage from the mishandling of pipe or from setting pipe on a rock often results in a coating holiday at the point of contact exposing the pipe to the threat of corrosion. This interaction accounted for 49 incidents in HL lines, as shown in Table B-6, but only three such cases were found for GAS lines.

For the HL transmission lines, 28 of the 49 incidents present evidence of coating damage, but no pipe wall damage, during construction. Fifteen (15) of those 28 cases correspond to coating damage when the pipe was drawn inside a casing and nine cases report debris or rocks in the backfill. Another group corresponds to 19 incidents with inadequate coating/tape practice and external corrosion. All three incidents in GAS lines were caused by damaged coating during construction and subsequent external corrosion.

Table B-6. EC + CD Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19860058	HL	EC	CD	IO	Pitting under disbonded coating	Reconditioned coat.
19860174	HL	EC	CD		Pinhole leak with coating damage since construction	
19870081	HL	EC	CD		Pitting. Backfill with rocks damaged coating	
19870111	HL	EC	CD		Coating apparently damaged during installation	Casing
19870137	HL	EC	CD		Pitting under disbonded coating	
19880043	HL	EC	CD		Pitting. Backfill with rocks damaged coating	
19890048	HL	EC	CD		Pitting under disbonded coating	
19890102	HL	EC	CD		Coating apparently damaged during installation	Casing
19900041	HL	EC	CD		Coating apparently damaged during installation	Casing
19910047	HL	EC	CD		Coating apparently damaged during installation	Casing
19910050	HL	EC	CD		Coating apparently damaged during installation	Casing
19910096	HL	EC	CD		Coating apparently damaged during installation	Casing
19910102	HL	EC	CD		Coating apparently damaged during installation	Casing
19910127	HL	EC	CD		Pitting. Backfill with debris damaged coating	
19910213	HL	EC	CD	IO	Pitting and crack under disbonded coating. Buckle.	
19920226	HL	EC	CD		Corrosion - dirt and moisture trapped under coating.	
19930009	HL	EC	CD		Pitting. Poor tape application.	
19950001	HL	EC	CD		Coating apparently damaged during installation	Casing
19950031	HL	EC	CD		External corrosion. Coating failure.	
19950078	HL	EC	CD		Pitting under disbonded coating	
19950138	HL	EC	CD		Coating apparently damaged during installation	Casing
19960066	HL	EC	CD		Pitting. Backfill with debris damaged coating	
19960142	HL	EC	CD		Pitting under disbonded coating	
19960169	HL	EC	CD		Coating apparently damaged during installation	Casing
19960192	HL	EC	CD		Pitting under disbonded coating	Reaconditioned coat.
19980006	HL	EC	CD		Pitting under disbonded coating	
19980080	HL	EC	CD		External corrosion. Coating failure.	
19980100	HL	EC	CD		Pitting under disbonded coating	
19980164	HL	EC	CD		Coating damaged under the thinsulator.	Casing
20000030	HL	EC	CD		Pitting. Poor tape application.	
20000058	HL	EC	CD		Pitting. Poor tape application.	
20010091	HL	EC	CD		External corrosion. Coating failure.	
20020022	HL	EC	CD		External corrosion. Coating failure.	
20020455	HL	EC	CD		Corrosion leak with coating damage since construction	Multiple owners
20030102	HL	EC	CD		Coating apparently damaged during installation	Casing
20030339	HL	EC	CD		Pinhole leak with coating damage since construction	
20040217	HL	EC	CD		Pitting. Backfill with debris damaged coating	
20060254	HL	EC	CD	IO	Inadequate backfill and conditions damaged coating.	
20070239	HL	EC	CD		Damaged field applied coating + Corrosion.	
20090147	HL	EC	CD		Inadequate backfill/rockbed made CP ineffective.	
20110141	HL	EC	CD		Pitting under casing spacer	Casing
20110219	HL	EC	CD		Cracked bend; corrosion under disbonded coating	
20120084	HL	EC	CD		Pinhole leak; line with original skid still embedded	
20130314	HL	EC	CD		Pinhole leak with coating damage since construction	
20130364	HL	EC	CD		Pitting under disbonded coating	
20140022	HL	EC	CD		Pitting. Poor tape application.	
20140197	HL	EC	CD		Pitting. Backfill with debris damaged coating	
20140300	HL	EC	CD		Coating apparently damaged during installation	Casing
20150099	HL	EC	CD		Coating apparently damaged during installation	Casing

External Corrosion and Malfunction of Control or Relief Equipment (EC + MCRE)

Malfunction of pressure control or relief equipment could result in temporary pressure increases. Pipelines, which may be experiencing deterioration from time-dependent mechanisms such as external or internal corrosion or SCC, would be at an increased likelihood of failure during the times the pressure is increased.

The EC + MCRE interaction accounted for only two incidents in HL lines; the narratives present a control valve failure which caused an overpressure of a corroded segment that failed prematurely. All five incidents in GAS lines with this interaction are shown in Table B-7 and present the same narrative as in HL lines.

Table B-7. EC + MCRE Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19860171	Gas	EC	MCRE		MCRE failure; overpressure; leak at corroded site	
20060077	Gas	EC	MCRE		Valve failure; MAOP exceeded.	
20110003	Gas	EC	MCRE	IO	External corrosion/erosion of a welllhead valve	
19850059	Gas	EC	MCRE		Pressure caused valve to leak in a corroded area	
19930041	Gas	EC	MCRE		MCRE failure; overpressure; leak at corroded site	

External Corrosion and Threads Stripped, Broken Pipe, Couplings (EC + TSBPC)

The EC + TSBPC accounted for three incidents in HL lines and two incidents in GAS lines. The three cases for HL lines report a leaking threaded cap/plug/connection due to galvanic corrosion. In contrast, the two incidents for GAS lines report Dresser couplings corroding in a system without CP protection with no bonds installed across the couplings when a CP system was initiated.

External Corrosion and Gasket Failure (EC + GF)

No significant interaction between external corrosion and gasket failure is expected. However, two incidents for GAS lines report two cases where a flange exhibited corroded bolts and abnormal flange deterioration. The HL lines do not report incidents with this interaction.

External Corrosion and Seal or Pump Packing Failure (EC + SPPF)

No significant interaction between external corrosion and seal or pump packing failure is expected. No incidents with this interaction were found in the DOT databases.

External Corrosion and Incorrect Operations (EC + IO)

From the standpoint of external corrosion (EC), the most significant aspect of incorrect operations (IO) pertains to improper control of the operation conditions, particularly during

transient operations. Unintentional valve closure can result in a pressure surge or overpressure of the line. The unintended overpressure can result in loss of containment if the pipe wall is corroded. Another potential interaction of incorrect operating procedures with external corrosion exists with compressor station discharge temperatures. The effects of such operating conditions are twofold. First, temperatures could be high enough to result in damage to the external coatings. Each coating system has a different maximum recommended operating temperature to avoid damage. If the recommended limits are exceeded, the coatings can experience damage including softening to the point where the coating is pulled away from the top of the pipe by melting or soil stress, it is perforated by debris in the soil, it disbonds from the pipe surface, or volatiles are driven off making the coating brittle and more susceptible to disbondment from soil stress. A second effect of high discharge temperatures is increasing the rate of corrosion-caused metal loss at areas of ineffective CP. Finally, incorrect maintenance practices can increase the likelihood of external corrosion. Incorrect operations which could adversely affect the function of the CP system include not maintaining adequate pipe-to-soil potential readings, and connecting the CP leads backwards.

EC + IO interaction accounted for 21 cases in HL lines (Table B-8) and six cases for GAS lines (Table B-9). Fifteen (15) of the 21 incidents in HL lines were caused by unwanted pressurization of a corroded line. In half of the cases there is evidence that the line actually leaked below the MOP. Only one GAS line incident follows the narrative of overpressure of corroded pipe segment. Four cases in HL lines and two cases for GAS lines are associated with CP interference or coating damage. Three incidents in HL lines have a vibration fatigue component; only one of such cases was found for GAS lines. Finally, three cases (one for HL lines and two for GAS) present miscellaneous maintenance malpractices.

Table B-8. EC + IO Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19860039	HL	EC	IO		Pressurisation below MOP. Leak in corroded area	
19870194	HL	EC	IO		Pressurisation of wrong line. Leak in corroded area	
19880033	HL	EC	IO		Pressurisation below MOP. Leak in corroded area	Loss of control
19880125	HL	EC	IO		Pressurisation below MOP. Leak in corroded seam	Power outage
19880172	HL	EC	IO		Pressurisation of wrong line. Leak in corroded area	Reverse flow
19880200	HL	EC	IO		Pressurisation of wrong line. Leak in corroded area	Blocked line
19920039	HL	EC	IO		Pressurisation of wrong line. Leak in corroded area	Power trip
19940258	HL	EC	IO		Pressurisation of wrong line. Leak in corroded area	
20000002	HL	EC	IO		Pressurisation below MOP. Leak in corroded area	Coating failure
20020055	HL	EC	IO		Corrosion under coating patch. CP interference	Not EC + CD
20030185	HL	EC	IO		Pressurisation below MOP. Leak in corroded area	
20040047	HL	EC	IO		Corrosion site wrongly reported	Contractor mistake
20040090	HL	EC	IO		Fatigue crack at the bottom of external metal loss	Unclear
20040140	HL	EC	IO		Coating damage from constant run off from tank	
20040313	HL	EC	IO		Corrosion due to contact with ground rod	Difficult to classify
20050188	HL	EC	IO		Pressurisation below MOP. Leak in corroded area	
20100088	HL	EC	IO	HRF	Fatigue flexing of tank bottom; Corrosion on soil side	
20100133	HL	EC	IO		CP interference from nearby installation; EC	
20110300	HL	EC	IO		Pinhle leak; Stray current	
20120232	HL	EC	IO		External corrosion and cycle fatigue cracking	
20120370	HL	EC	IO		Overpresurisation. Leak in corroded area	>MOP

Table B-9. EC + IO Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19850038	Gas	EC	IO		Overpressure and failure at corroded area.	
19850186	Gas	EC	IO		Rectifier out of service for long period. Corrosion.	
19860101	Gas	EC	IO		Corrosion accelerated by temperature. Vibration.	
20040062	Gas	EC	IO		Line isolated from CP. Corrosion.	
20100056	Gas	EC	IO		Pinhole corrosion. Defective sanblasting operation.	
20100063	Gas	EC	IO		Pinhole corrosion. Defective sanblasting operation.	

External Corrosion and Third Party Damage (EC + TP)

Third party damage (immediate failure) would not allow sufficient time for external corrosion to act. No incidents with EC + TP were found.

External Corrosion and Previously Damaged Pipe (EC + PDP)

Mechanical damage may damage coating and expose the pipe to potential corrosion to a greater degree than would be the case where no damage exists. While the damage itself is the primary threat, subsequent corrosion, if it occurs, can further reduce the remaining strength of the pipe.

The EC + PDP interaction accounted for 11 cases in HL lines (Table B-10) and four cases in GAS lines (Table B-11). All cases presented corrosion happening at sites with unrepaired coating or pipe wall impact damage.

Table B-10. EC + PDP Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19960135	HL	EC	PDP		Impact damaged coating; corrosion pinhole.	
19980122	HL	EC	PDP		Impact damaged coating; corrosion pinhole.	
20010108	HL	EC	PDP		Impact damaged coating; corrosion pinhole.	
20020392	HL	EC	PDP		Coating of riser damaged; corrosion in splash zone	Ineffective armor
20040042	HL	EC	PDP		Localized pitting and prior damage	
20070210	HL	EC	PDP		Impact damaged coating; corrosion pinhole.	
20090116	HL	EC	PDP		Localized pitting and prior damage	
20100158	HL	EC	PDP		Localized pitting and prior damage	
20110163	HL	EC	PDP		Impact damaged coating; corrosion pinhole.	
20130106	HL	EC	PDP		Localized pitting and prior damage	
20140223	HL	EC	PDP		Impact damaged coating; corrosion pinhole.	

Table B-11. EC + PDP Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19880228	GAS	EC	CD		Damaged pipe; extensive corrosion	
20070025	GAS	EC	CD		Damaged pipe; corrosion pinhole.	
20080011	GAS	EC	CD		Impact damaged coating; corrosion pinhole.	
20130073	GAS	EC	CD	IO	Impact damaged coating; pinhole; CP interference	

External Corrosion and Vandalism (EC + V)

No significant interaction between external corrosion and vandalism has been established. No incidents with EC + V interactions were found.

External Corrosion and Earth Movement (EC + EM)

Earth movement such as subsidence or landslides creates significant axial stress in pipelines. Pipelines which have been affected by significant metal loss could be considered to be more susceptible to axial stresses; however, this was not reflected in the pipeline incident data review. One case of EC + EM occurred in an HL line, and an additional one occurred in a GAS line. Both were caused by soil erosion that left exposed a section of the line that was then subject to external corrosion.

External Corrosion and Heavy Rains and Floods (EC + HRF)

The rationale for no significant interaction between external corrosion and heavy rains and floods is the same as that given for the interaction between external corrosion and earth movement. EC + HRF accounted for two incidents in HL lines and one incident in GAS lines. They all occurred in tanks and their associated pipe systems.

External Corrosion and Lightning (EC + LIGHT)

Lightning could also result in damage to above ground equipment, cathodic protection systems, including rectifiers, insulating gaskets or components, or other equipment. Because CP equipment is subjected to routine maintenance and monitoring, the amount of time the CP

system would be expected to be out of service following lightning damage would be small, on the order of months, which would not be long enough to result in significant metal loss from external corrosion. No cases of EC + LIGHT were found.

External Corrosion and Cold Weather (EC + CW)

Reportable incident data suggest that the overwhelming majority of cold weather incidents arise either from the freezing of trapped water or the introduction of excessive axial stress from thermal contraction. Only two incidents in HL lines present EC + CW interactions; ice blockage of a line created an overpressure of a line that leaked at a corrosion site.

Internal Corrosion and Stress Corrosion Cracking (IC + SCC)

While it is conceivable that internal corrosion and stress corrosion cracking at the OD surface could occur at the same location in a pipeline, the causes of the two would be completely unrelated to one another. No IC + SCC interactions were found in HL or GAS lines.

Internal Corrosion and Defective Pipe (IC + DP)

Internal corrosion chemical reactions result in the release of monatomic hydrogen at the internal pipe surface. A hydrogen concentration gradient is established through the pipe wall. Hydrogen atoms are small enough to diffuse into the pipe wall and migrate from high to low concentration. The hydrogen can collect at voids or layers of non-metallic inclusions or laminations where the atomic hydrogen will coalesce to form diatomic hydrogen or hydrogen gas. The hydrogen gas molecule, much larger than the hydrogen atom, is trapped within the pipe steel. If allowed to continue, the hydrogen accumulates and the pressure builds until a blister or separation in the pipe wall occurs. The likelihood of laminations existing, especially in pre-1980s pipe, is high. However, no incidents with IC + DP interaction were found in either HL or GAS lines.

Internal Corrosion and Defective Pipe Seams (IC + DPS)

As described under EC + DPS, some older ERW (not necessarily only low frequency) and flash-welded seam materials are susceptible to selective or "grooving" corrosion. This phenomenon can occur when the pipe is undergoing either external or internal corrosion-caused metal loss, and the metal loss affects the area of the seam.

IC + DPS interactions accounted for two incidents in HL lines and 11 incidents in GAS lines (Table B-12). All cases presented evidence of selective seam weld corrosion.

Table B-12. IC + DPS Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19840944	Gas	IC	DPS		Selective seam weld corrosion	ERW
19910131	Gas	IC	DPS		Internal selective seam weld corrosion	Flashwelded
19930015	Gas	IC	DPS		Internal selective seam weld corrosion	ERW
19940182	Gas	IC	DPS		Internal selective seam weld corrosion	ERW
19940201	Gas	IC	DPS		Internal selective seam weld corrosion	ERW
19960031	Gas	IC	DPS		Internal selective seam weld corrosion	ERW
19970079	Gas	IC	DPS		Internal selective seam weld corrosion	ERW
20090022	Gas	IC	DPS		Groove and corrosion consistent with SSWC	ERW
20130077	Gas	IC	DPS		Internal selective seam weld corrosion	ERW
20130084	Gas	IC	DPS		Internal selective seam weld corrosion	ERW
20140113	Gas	IC	DPS		Internal selective seam weld corrosion	

Internal Corrosion and Defective Fabrication Welds (IC + DFW)

There is little evidence to suggest that internal corrosion and defective fabrication welds interact to create a special threat. Only two cases in HL lines suggest IC + DFW interaction; the narratives tell of a pinhole on a fabrication weld with a groove.

Internal Corrosion and Defective Girth Welds (IC + DGW)

The girth welding process alters the microstructure of the pipe base metal, resulting in a heat affected zone, and usually involves the deposition of filler metal with a similar, but different chemistry than the pipe base metal. Despite these differences in chemical composition and microstructure, no significant inherent susceptibility to internal or external corrosion has been identified. Kiefner has observed instances of corrosion that was apparently more aggressive in the weld heat affected zone and/or deposited weld metal, but these have been isolated cases.

IC + DGW interactions accounted for five incidents in HL lines (Table B-13) and eight incidents in GAS lines (Table B-14). All cases present preferential corrosion at weld defects.

Table B-13. IC + DGW Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19870038	HL	IC	DGW		Pinhole at girth weld defect	
20090296	HL	IC	DGW		MIC at girth weld cavity/mistmach	
20100316	HL	IC	DGW		Pinhole at girth weld with inadequate penetration	
20110390	HL	IC	DGW		Pinhole at girth weld defect	
20130284	HL	IC	DGW		Pinhole at girth weld with inadequate penetration	

Table B-14. IC + DGW Interactions for Gas Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19850028	Gas	IC	DGW		IC of a defective girth weld located at a low spot	
19970083	Gas	IC	DGW		Internal corrosion of a defective girth weld	
19970135	Gas	IC	DGW		Internal corrosion of a defective girth weld	
19970157	Gas	IC	DGW		Internal selective seam corrosion of girth weld	
20050024	Gas	IC	DGW		Internal pinhole in defective girth weld	
20080016	Gas	IC	DGW		Pinhole corrosion failure in joint offshore	
20130071	Gas	IC	DGW		Internal corrosion of a defective girth weld	
20110018	Gas	IC	DGW		Internal pinhole in defective girth weld	

Internal Corrosion and Construction Damage (IC + CD)

No significant interaction between internal corrosion and construction damage has been theorized. No IC + CD interactions were found in the HL and GAS lines.

Internal Corrosion and Malfunction of Control or Relief Equipment (IC + MCRE)

The threat of internal corrosion is considered to interact with the threat of malfunction of control and relief equipment for the reasons explained previously under External Corrosion (and other causes) and Malfunction of Control or Relief Equipment. This interaction accounted for one incident in HL lines and three incidents in GAS lines.

Internal Corrosion and Threads Stripped, Broken Pipe, Couplings (IC + TSBPC)

There would seem to be little chance of interaction between the threat of internal corrosion and the threats associated with threads stripped, broken pipe, or couplings. However, three incidents in Hl lines were attributed to IC + TSBPC; the narrative simply reports internal corrosion on a threaded connection/fitting.

Internal Corrosion and Gasket Failure (IC + GF)

Internal corrosion associated with the formation of a wet corrosive environment can interact with flanged joints. The liquids can collect in the gap between the flanges created by either raised face or ring-type groove gaskets. Pitting or crevice corrosion can occur along the gasket sealing surfaces. The corrosion can progress along the interface between the gasket and the sealing surfaces of the flanges to the point where the either a leak path is created, or the clamping force is reduced allowing the gasket to fail, resulting in leakage.

The IC + GF interaction accounted for only one incident in HL lines; it was not found in the database for GAS lines.

Internal Corrosion and Seal or Pump Packing Failure (IC + SPPF)

No significant interaction between internal corrosion and seal or pump packing failure has been observed. No IC + SPPPF interactions were found in the HL and GAS lines.

Internal Corrosion and Incorrect Operations (IC + IO)

Internal corrosion can be mitigated by invoking certain operating procedures when conditions which can lead to internal corrosion are present. If these operating procedures are not performed at the frequency required by the operating conditions, then internal corrosion could occur.

The IC + IO interaction accounted for only three incidents in HL lines; no incidents in GAS lines were associated with this interaction. Two of the cases are associated with deficient design and maintenance practices (deadlegs/low points).

Internal Corrosion and Third Party Damage (IC + TP)

Third party damage (immediate failure) would not allow sufficient time for internal corrosion to act. No incidents with IC + TP were accounted.

Internal Corrosion and Previously Damaged Pipe (IC + PDP)

There is no apparent interaction between the threat of internal corrosion and threat of previously damaged pipe. No incidents with IC + PDP were accounted.

Internal Corrosion and Vandalism (IC + V)

There is no apparent interaction between the threat of internal corrosion and threat of vandalism. No incidents with IC + V were accounted.

Internal Corrosion and Earth Movement (IC + EM)

There is no apparent interaction between the threat of internal corrosion and threat of earth movement. No incidents with IC + TP were accounted.

Internal Corrosion and Heavy Rains and Floods (IC + HRF)

There is no apparent interaction between the threat of internal corrosion and the threat of heavy rains and floods. No incidents with IC + TP were accounted.

Internal Corrosion and Lightning (IC + LIGHT)

There is no apparent interaction between the threat of internal corrosion and the threat of lightning. No incidents with IC + TP were accounted.

Internal Corrosion and Cold Weather (IC + CW)

There is no apparent interaction between the threat of internal corrosion and the threat of cold weather. No incidents with IC + TP were accounted.

SCC and Defective Pipe (SCC + DP)

Pipe body flaws and defects such as mill grind repairs, roll marks in the plate, hard spots, and even residual stress can contribute to SCC susceptibility. Local stress concentrators increase the probability of SCC initiation if the conditions for SCC are present. The SCC + DP interaction accounted for only one incident in GAS lines; the investigation concluded that that failure occurred because of the confluence of a hard spot in the pipe body and the high pH SCC.

SCC and Defective Pipe Seams (SCC + DPS)

SCC has been associated with hard microstructural areas, such as DC- and low-frequency ERW seams that have not been subjected to a post-weld heat treatment, contact burns associated with the seam welding, and double submerged arc welded (DSAW) seams which contain stress concentrations along the weld toe, such as undercut or incomplete fill where part of the welding groove if left exposed. The SCC + DPS interaction accounted for only two incidents in HL lines; the narratives report selective seam weld corrosion with cracking that suggests SCC.

SCC and Defective Fabrication Weld (SCC + DFW)

SCC has been known to occur along the HAZ of branch connections, saddle reinforcements, and half-soles and patches. Some coatings are difficult to apply to these connections (polyethylene tapes) and additional stresses associated with some branch connections increase the likelihood of SCC. Improperly aligned and/or supported branch connections have been affected by bending loads that contribute to SCC. The SCC + DFW interaction accounted for only two incidents in HL lines; the narratives are very sparse and report evidence of stress crack on defective fabrication welds.

SCC and Defective Girth Weld (SCC + DGW)

SCC has been known to occur at girth welds more readily than in the parent pipe. Two contributing factors are believed to be the residual stresses associated with the girth weld, and the use of a different coating system at girth welds in shop-coated pipes. If the field-joint coating system is prone to disbondment and shields the pipe from cathodic protection, the threat of SCC increases. The SCC + DGW interaction accounted for only one incident in HL lines; unfortunately, the narrative does not provide details about the investigation.

SCC and Construction Damage (SCC + CD)

Construction damage from the mishandling of pipe or from setting pipe on a rock often results in a coating holiday at the point of contact exposing the pipe to the threat of SCC. The SCC + CD interaction accounted for only one incident in HL lines; the investigation concluded that SCC initiated on a dent, from the pipe resting on a rock.

SCC and Malfunction of Control or Relief Equipment (SCC + MCRE)

The threat of stress corrosion cracking is considered to interact with the threat of malfunction of control and relief equipment for the reasons explained previously under External Corrosion and Malfunction of Control or Relief Equipment. No incidents with SCC + MCRE were accounted.

SCC and Threads Stripped, Broken Pipe, and Couplings (SCC + TSBPC)

There is no anticipated interaction between SCC and threads stripped, broken pipe, and couplings. No incidents with SCC + TSBPC were accounted.

SCC and Gasket Failure (SCC + GF)

There is no anticipated interaction between SCC and gasket failure. No incidents with SCC + GF were accounted.

SCC and Seal or Pump Packing Failure (SCC + SPPF)

There is no anticipated interaction between SCC and seal or pump packing failure. No incidents with SCC + SPPF were accounted.

SCC and Incorrect Operations (SCC + IO)

Pressure excursions, operating with elevated discharge temperatures, and failure to maintain adequate CP can contribute to conditions which increase the likelihood of SCC initiating and growing. The SCC + IO interaction accounted for only two cases in HL lines, where SCC grew by corrosion fatigue (excessive vibration).

SCC and Third Party Damage (SCC + TP)

Third party damage (immediate failure) would not allow sufficient time for SCC to act. No incidents with SCC + TP were accounted.

SCC and Previously Damaged Pipe (SCC + PDP)

Previous mechanical damage typically results in damage or removal of the pipe's external coating and the formation of a dent and gouge in the pipe wall. The damage represents a significant stress riser and the damage to the coating allows the soil environment to contact the

pipe surface. If the CP at the location is not completely effective, SCC can develop. The SCC + PDP interaction accounted for only one case in HL lines; it was a crack on a gouge.

SCC and Vandalism (SCC + V)

There is no conceivable connection between the threat of SCC and vandalism. No incidents with SCC + V were accounted.

SCC and Earth Movement (SCC + EM)

Earth movement such as settlement, subsidence, erosion, or landslides will result in an increased longitudinal stress on the pipeline. If the earth movement is sudden, such as with a landslide, there will not be sufficient time for SCC to develop and grow; however, in many cases the movement is gradual, occurring over many years. Where the environment for SCC is present and is allowed to contact the pipe surface, SCC can initiate and grow over time. The orientation of the SCC will be perpendicular to the primary stress, which in the case of earth movement areas, is frequently axial stress. Thus, circumferentially-oriented SCC could occur in these areas. The SCC + EM interaction accounted for only one case in HL lines; the investigation reported that stress crack growth was influenced by external soil forces.

SCC and Heavy Rains and Floods (SCC + HRF)

Heavy rains and floods often cause rapidly developing failures if the soil cover of the pipeline is removed and the pipeline is suspended in the flowing water. Such a failure would occur too quickly to allow SCC to develop in response to the increase in axial tensile stress. However, if the flood water merely destabilizes the soil, the pipeline could become subjected to increased longitudinal load. No incidents with SCC + HRF were accounted.

SCC and Lightning (SCC + LIGHT)

There is no known connection between the threat of SCC and the threat of lightning. No incidents with SCC + LIGHT were accounted.

SCC and Cold Weather (SCC + CW)

There is no known interaction between the threat of SCC and the threat of cold weather. No incidents with SCC + CW were accounted.

Defective Pipe and Defective Pipe Seam (DP + DPS)

These two threats can exist simultaneously, but they can interact if and only if they exist in close proximity. In effect, the defects created by the threats must interact to lower the resistance to failure. One case in an HL line is considered to represent a DP + DPS interaction. The narrative reports the long seam contained a lack of fusion that linked with an embedded inclusion in the pipe body.

Defective Pipe or Defective Pipe Seam and Defective Fabrication Weld (DP or DPS + DFW)

Defective pipe including laminations, brittle properties, high carbon equivalent levels, or hard spots that intersect with branch connections or repair sleeves, patches or half-soles, could result in loss of containment. High carbon equivalent levels in the base metal increase the risk of hydrogen cracking. Using techniques to avoid the formation of crack-susceptible microstructures (such as pre- or post-heating) or reducing the amount of hydrogen present in the welding environment (*e. g.*, using a low-hydrogen welding process) reduces these risks. No incidents with DP/DPS + DFW were encountered.

Defective Pipe or Defective Pipe Seam and Defective Girth Weld (DP or DPS + DGW)

Laminations and high carbon equivalent levels in the pipe base metal can lead to girth weld problems. High carbon equivalent levels in the base metal increase the risk of hydrogen cracking. Using techniques to avoid the formation of crack-susceptible microstructures (such as pre- or post-heating) or reducing the amount of hydrogen present in the welding environment (*e. g.*, using a low-hydrogen welding process) reduces these risks. No incidents with DP/DPS + DGW were encountered.

Defective Pipe or Defective Pipe Seam and Construction Damage (DP or DPS + CD)

Construction damage such as a buckle, a wrinkle bend, dent, or a gouge could overlap with a pipe body defect such as a hard spot. The occurrence of the construction damage with a pipe body defect in a pipe with low strength or with thickness significantly less than the specified thickness could result in a more severe situation compared to the same construction damage in sound pipe. However, the coincidence of damage and such pipe attributes is considered to be a low-probability event. No incidents with DP + CD were accounted and only one case for HL lines presented DPS + CD; the narrative of the interaction presents the case of a pipe sitting on a rock, which caused a dent, and the defective ERW seam positioned at the bottom of the pipe.

Defective Pipe or Defective Pipe Seam and Malfunction of Control or Relief Equipment (DP or DPS + MCRE)

The threat of defective pipe or a defective pipe seam is considered to interact with the threat of malfunction of control and relief equipment as explained previously under External Corrosion (and other causes) and Malfunction of Control or Relief Equipment if the pipeline has not been subjected to a prior pressure test to a pressure level of at least 1.25 times the MAOP.

The interaction DP + MCRE accounted for only one incident in GAS pipelines; the narrative reported pressure increment resulting from thermal build-up due to a defective protection

device that caused the defective pipe body to fail. The interaction DPS + MCRE accounted for one incident in HL lines and one incident in GAS lines; the narratives reported thermal build-up due to a defective protection device that caused the pipe seam to fail.

Defective Pipe or Defective Pipe Seam and Threads Stripped, Broken Pipe, or Coupling, (DP or DPS + TSBPC)

Threads stripped, broken pipe, and coupling failures (with the exception of Dresser couplings) are usually associated with small-diameter (<2-inch NPS) piping and tubing. No incidents with DP/DPS + TSBPC were accounted.

Defective Pipe or Defective Pipe Seam and Gasket Failure (DP or DPS + GF)

Gaskets are associated with flanged joints that are affected by the condition of the flanges and bolt load. Therefore, there is no perceived interaction between defective pipe or defective pipe seams and gasket failure. No incidents with DP/DPS + GF were accounted.

Defective Pipe or Defective Pipe Seam and Seal or Pump Packing Failure (DP or DPS + SPPF)

Seals and pump packing failure is associated with equipment such as valves, pumps, and instrumentation piping. Therefore, there is no perceived interaction between defective pipe or defective pipe seams and seals or pump packing failure. No incidents with DP/DPS + SPPF were accounted.

Defective Pipe and Defective Pipe Seams and Incorrect Operation (DP or DPS + IO)

DP + IO interactions accounted for five incidents in HL lines (Table B-15). No cases of such interactions were found for GAS lines. All five cases in HL lines involved either vibration or thermal-fatigue-induced cracking which initiated at pipe defects, such as laminations.

Table B-15. DP + IO Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
20110251	HL	DP	IO		Vibration fatigue crack grew over pipe defect	
20120085	HL	DP	IO		Vibration fatigue crack grew at the edges of lamination	
20130030	HL	DP	IO		Vibration fatigue crack grew at the edges of lamination	
20150011	HL	DP	IO		Vibration fatigue crack grew over defect (chem attack)	
20150121	HL	DP	IO		Thermal fatigue + pipe wrinkle	

DPS + IO interactions accounted for 11 incidents in HL lines (Table B-16). No cases of such interaction were found for GAS lines. Nine of the 11 cases in HL lines reported vibration or thermal-fatigue-induced cracking which initiated at weld defects, such as hook cracks.

Table B-16. DPS + IO Interactions for HL Transmissions Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
20050034	HL	DPS	IO		Pressure cycles + burned metal cracking	Lap welded
20070029	HL	DPS	IO		No details	ERW
20070230	HL	DPS	IO		Fatigue cracking initiated at seam defect	DSAW
20070350	HL	DPS	IO		No details	SAW
20110206	HL	DPS	IO		Thermal fatigue + pipe wrinkle	Lap welded
20120079	HL	DPS	IO		Severe operation conditions + integranular cracks	DSAW
20120248	HL	DPS	IO		Fatigue cracking initiated at hook crack defect	ERW
20120374	HL	DPS	IO		Fatigue cracking initiated at hook crack defect	ERW
20130194	HL	DPS	IO		Fatigue cracking; insufficient well penetration	
20130223	HL	DPS	IO		Fatigue cracking initiated at seam defect	LF-ERW
20130405	HL	DPS	IO		Fatigue cracking initiated at seam defect	LF-ERW

Buried pipelines are usually cathodically protected against external corrosion in the moist soil environment. Cathodic protection (CP) has made it possible for pipelines to remain in service for decades, even with coating systems that lack the performance advantages of modern coatings technology. A CP system is required on buried pipelines by most pipeline regulations and standards.

Corrosion involves the separation of electrons (oxidation) from the metal, at the anode, and the consumption of those electrons by some other reaction (reduction), at the cathode [49]. Dissolution of the metal ions in the electrolyte in the anodic reaction results in the actual metal loss. The corrosion process involves the flow of electrons from the anode to the cathode, and the flow of current from the anode to the environment. Therefore it can be controlled by a voltage. Cathodic protection mitigates external corrosion on a pipeline by inducing an electrical potential at the pipe surface such that where a breach of the coating exposes the pipe surface to the soil environment, current flows onto the pipe. In order to assure that cathodic potentials are great enough to mitigate corrosion at all points along the pipeline, operators often induced larger electrical potentials than the minimum required. In so doing, larger quantities of hydrogen may evolve at the anode. Hydrogen is usually assumed to dissipate harmlessly into the environment, but it may also diffuse into the pipe metal.

Diffusible hydrogen can cause metallurgical damage to steel by one or more possible mechanisms [50]:

- Atomic hydrogen concentrates in areas of triaxial tensile stress ahead of a crack or notch in sufficient quantity to weaken metallic atomic bonds and cause an increment of crack growth. Hydrogen then re-diffuses to the triaxial stress field ahead of the enlarged crack and the process repeats.
- Atomic hydrogen promotes mobility of slip planes, localization of deformation, and microvoid coalescence, resulting in crack enlargement.

- Atomic hydrogen collected at an embedded void or interface forms molecular hydrogen (H_2) which has a significantly larger volume (the diameter ratio of molecular to atomic hydrogen is approximately 2.4), causing a buildup of internal pressure. The resulting internal stress increases to the point where cracking advances, in conjunction with either the bond-weakening or strain-localization model.

The effect of diffused hydrogen can be spontaneous instability of resident features in the pipe that may have successfully withstood a hydrostatic pressure test and which would ordinarily be considered benign or "stable" in natural gas service. Examples of such features include: metallurgical hard spots in the pipe body, laminations, hard microstructures in ERW seams that were not subjected to post-weld heat-treatment, and mechanical damage. The authors are aware of pipeline failures involving each of these types of features that had been successfully pressure tested, that exhibited no evidence of fatigue crack growth, and where hydrogen was suspected to have been introduced by CP systems operated at high levels of overprotection.

Defective Pipe or Defective Pipe Seam and Third Party Damage, Previously Damaged Pipe, and Vandalism (DP or DPS + TP, PDP, V)

Defective pipe, where the defect is a high transition temperature making the material susceptible to brittle fracture initiation at a defect, is more susceptible to failure from mechanical damage whether the damage occurs immediately (TP), through a delayed failure (PDP) or through vandalism (V) (assuming that the vandalism is in the form of damage to line pipe rather than to a component). The low fracture toughness levels reduce the ability of the pipe to tolerate damage without initiating a crack; it also lowers the material's resistance to crack propagation. The interaction between a defective pipe seam and previously damaged pipe needs to be considered because seams are frequently located intentionally in the top quadrant of a pipeline where they are most exposed to damage. However, no incidents were attributed to any of these interactions either in HL or in GAS lines.

Defective Pipe or Defective Pipe Seam and Earth Movement (DP or DPS + EM)

There would seem to be little chance of interaction between the threat of defective pipe or defective pipe seam and the threat of earth movement. It is true that an under-strength or under-thickness pipe is more susceptible to the adverse effects of added axial stress than a pipe which meets specifications. However, the fact that a line pipe material must conform to specifications and be checked by random sampling assures that very few units are under-strength or under-thickness.

DP + EM interactions accounted for only two incidents in HL lines. Both reports indicated that pipe settlement resulted in complex loadings that initiated a crack at a discontinuity in the pipe

body. DPS + EM interaction accounted for one incident in HL lines and one incident in GAS lines where the narrative simply reports earth movement that cracked open a defective longitudinal seam.

Defective Pipe and Defective Pipe Seams and Heavy Rains and Floods (DP or DSP + HRF)

There is no significant interaction between the threat of defect pipe or defective pipe seam and the threat of heavy rains and floods. It is true that an under-strength or under-thickness pipe is more susceptible to the adverse effects of added axial stress than a pipe which meets specifications. However, the fact that a line pipe material must conform to specifications and be checked by random sampling assures that very few units are under-strength or under-thickness. No incidents with DP/DPS + HRF were accounted.

Defective Pipe and Defective Pipe Seams and Lightning (DP or DSP + LIGHT)

There is no significant interaction between the threat of defective pipe or defective pipe seam and the threat of lightning. It is true that that under-thickness pipe could be penetrated more readily by lightning current than a pipe which possesses the specified thickness. However, the fact that a line pipe material must conform to specifications and be checked by random sampling assures that very few units are under-thickness. No incidents with DP/DPS + LIGHT were accounted.

Defective Pipe and Defective Pipe Seams and Cold Weather (DP or DSP + CW)

There is no significant interaction between the threat of defect pipe or defective pipe seam and cold weather. It is true that pipe with a high transition temperature would tend more toward brittle behavior in cold weather than a pipe with a lower transition temperature. However, from the standpoint of brittle behavior, experience has shown that even with older pipe materials brittle fracture initiation, on rare occasions when it occurs, is usually associated with mechanical damage incidents or seam splits from selective seam corrosion.

DP + CW interaction accounted for only one incident in an HL line; ice upheaval lifted the line and cracked the pipe body at a mill defect. No incidents in GAS lines were found to have been caused by the DPS + CW interaction.

Defective Fabrication Weld and Defective Girth Weld (DFW + DGW)

It would seem that threats from these two types of welds are mutually exclusive. Only one incident in HL lines presented this interaction in a rather complex scenario: the incident was

classified as DFW + DGW + TSBPC and reported a GW fatigue fracture initiated at a poor repair weld; it was later found that a pump coupling failure was the source of the cyclic stress.

Defective Fabrication Weld and Construction Damage (DFW + CD)

These two threats are considered to interact because bypass piping at valves, or vents, or other appurtenances can be struck by construction equipment and enter service damaged. No incidents with DFW + CD were accounted.

Defective Fabrication Weld and Malfunction of Control and Relief Equipment (DFW + MCRE)

There is no perceived interaction between the threat of defective fabrication weld and the threat associated with malfunction of control and relief equipment failure because fabrication welds are associated primarily with large pipe and major appurtenances while control and relief equipment failure is associated primarily with regulators, valves and instrumentation piping. No incidents with DFW + MCRE were accounted.

Defective Fabrication Weld and Threads Stripped, Broken Pipe, or Coupling (DFW + TSBPC)

There is no perceived interaction between the threat of defective fabrication weld and the threat associated with stripped threads, broken pipe, or couplings because fabrication welds are associated primarily with large pipe and major appurtenances while stripped threads and coupling failure are associated primarily with joint types that are not welded or broken pipe failure that does not involve welds. Only one incident in HL lines presented this interaction in a rather complex scenario.

Defective Fabrication Weld and Gasket Failure (DFW + GF)

There is no perceived interaction between the threat of defective fabrication weld and the threat of gasket failure because fabrication welds are associated primarily with large pipe and major appurtenances while gasket failure is associated primarily with bolted joints. No incidents with DFW + GF were encountered.

Defective Fabrication Weld and Seal or Pump Packing Failure (DFW + SPPF)

There is no perceived interaction between the threat of defective fabrication weld and the threat associated with seal or pump packing failure because fabrication welds are associated primarily with large pipe and major appurtenances while seals and pump packing failure is associated with rotating equipment failure (*i. e.*, pumps and compressors). No incidents with DFW + SPPF were accounted.

Defective Fabrication Weld and Incorrect Operation (DFW + IO)

Mechanical vibration or pressure pulsations from inadequate design can lead to failure. Inadequate design or the failure to implement measures to prevent the vibration or movement of the pipe or components would be considered a form of incorrect operation. The vibration can manifest itself as fatigue failures at branch connections on pulsation bottle nozzles or other branch connection joints (*e. g.*, a drain pipe on a header pipe).

The DFW + IO interactions accounted for 17 incidents in HL lines (Table B-17) and one incident in GAS lines. Fifteen (15) of the 17 incidents in HL lines are due to excessive vibration initiating a crack in a weld defect.

Table B-17. DFW + IO Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19920050	HL	DFW	IO		Hook crack defect propagated by vibration fatigue.	Assumed FW
20020227	HL	DFW	IO		Vibration fatigue crack initiated at weld imperfection	
20020386	HL	DFW	IO		Vibration fatigue crack initiated at weld defect	
20030175	HL	DFW	IO		Weld with 30 degree misalignment and erosion	
20040358	HL	DFW	IO		Vibration fatigue crack initiated at weld defect	
20090076	HL	DFW	IO		Overload, lack of support and excessive HAZ zone	
20090218	HL	DFW	IO		Vibration fatigue crack initiated at weld defect	
20100115	HL	DFW	IO		Vibration fatigue crack initiated at weld defect	
20100312	HL	DFW	IO		Pressure cycle fatigue crack initiated at weld defect	Bending stresses
20110380	HL	DFW	IO		Repair sleeve leaked from defective weld + bending	
20110452	HL	DFW	IO		Repair sleeve leaked from defective weld + fatigue	
20120004	HL	DFW	IO		Vibration fatigue crack initiated at weld defect	
20120005	HL	DFW	IO		Vibration fatigue crack initiated at weld defect	
20120058	HL	DFW	IO		Vibration fatigue crack initiated at weld defect	
20130304	HL	DFW	IO		Vibration fatigue crack initiated at weld defect	
20140073	HL	DFW	IO		Vibration fatigue crack initiated at weld defect	
20150081	HL	DFW	IO		Vibration fatigue crack initiated at weld defect	

Incidents with failed sleeves or patches are difficult to classify under the guideline used for reviewing the DOT incident databases. A failed repair can be considered a threat interaction from the original leak in the line and the failure in the sleeve/patch. Kiefner accounted 14 incidents with a sleeve or plate leaking from a defective fabrication weld and classified them as DFW + IO (Table B-18); the IO component is a token, since the original cause of the pipe leak is unknown. Another option would have been to classify these cases as DFW + PDP. The 14 incidents reported in Table B-18 were not included in the interactions count because (1) it is a consideration that needs further discussion and (2) it would drive the DFW + IO count up.

Table B-18. Repair Sleeve Failures with Apparent DFW + IO Interaction

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19900044	HL	DFW	IO		Defective weld in previous repair leaked	
19910062	HL	DFW	IO		Repair sleeve leaked from defective weld	
19910178	HL	DFW	IO		Repair sleeve leaked from defective weld	
19920097	HL	DFW	IO		Defective weld in previous repair leaked	Leak plate
19920110	HL	DFW	IO		Defective weld in previous repair leaked	
19930101	HL	DFW	IO		Support sleeve leaked from defective weld	
19940122	HL	DFW	IO		Cracked weld on previous repair	
19940123	HL	DFW	IO		Defective weld in previous repair leaked	
19940124	HL	DFW	IO		Defective weld in previous repair leaked	
19950063	HL	DFW	IO		Repair sleeve leaked from defective weld	
19990153	HL	DFW	IO		Repair sleeve leaked from cracked weld	
20000067	HL	DFW	IO		Repair sleeve leaked from defective weld	
20000094	HL	DFW	IO		Repair sleeve leaked	
20000101	HL	DFW	IO		Repair sleeve leaked from defective weld	

Defective Fabrication Weld and Third Party Damage (DFW + TP)

The probability of damage to fabrication welds from mechanical damage is considered to be negligible. However, DFW + TP accounted for one incident in HL lines and two incidents in GAS lines. In one case, a bent marking post was found attached to the pipeline by a defective fabrication weld that eventually cracked. In another incident, mats were laid down to stabilize the terrain for heavy equipment; the mats slid down the trench and hit a farm tap breaking the defective fabrication weld.

Defective Fabrication Weld and Previously Damaged Pipe (DFW + PDP)

The probability of damage to fabrication welds from mechanical damage resulting in delayed failure is considered to be negligible. Only one incident for HL lines was considered presenting the DFW + PDP interaction; a segment with a dent had a sleeve installed with a defective fabrication weld. Eventually the dent leaked and pressurized the sleeve. The sleeve leaked at the weld defect.

Defective Fabrication Weld and Vandalism (DFW + V)

The probability of damage to fabrication welds from vandalism is considered to be negligible. No incidents with DFW + V were encountered.

Defective Fabrication Weld and Earth Movement (DFW + EM)

Fabrication welds can often involve the attachment of rather heavy components to the pipeline, typically valves, but also heavy sleeves or bolt-on clamps. If not properly supported, the weight of these components can lead to differential settlement, resulting in severe bending stresses at the fabrication welds. The stresses can be large enough to initiate cracks, buckles, or increase the likelihood of SCC. DFW + EM interaction accounted for one incident in an HL pipeline and

five incidents in GAS lines (Table B-19). The narratives of all incidents reported ground movement (generally soil subsidence) that overstressed the line at a welded connection (generally a tap).

Table B-19. DFW + EM Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19940186	Gas	DFW	EM		Differential settlement caused failure of connection	
20080150	Gas	DFW	EM		Stub exterted stress on defective weld	
20040103	Gas	DFW	EM		Soil contraction, pulled on tap, leak at crack in weld	
20060073	Gas	DFW	EM		Cumulative load upon failed weld.	
20140042	Gas	DFW	EM		Construction defect and ground movement	

Defective Fabrication Weld and Heavy Rains and Floods (DFW + HRF)

Defective fabrication welds would be more susceptible to bending loads resulting from heavy rains and floods, eroding of backfill, or floating of pipe (*e. g.*, increased axial stress). DFW + HRF interactions accounted for one incident in an HL line and one incident in a GAS line. In one case, a reinforcing weld of the roof drain cracked during an event of heavy rain.

Defective Fabrication Weld and Lightning (DFW + LIGHT)

There is no apparent interaction between defective fabrication welds and lightning. No incidents with DFW + LIGHT were accounted.

Defective Fabrication Weld and Cold Weather (DFW + CW)

There would seem to be little chance of interaction between defective fabrication welds and cold weather. However, this interaction accounted for one incident in a HL line and one incident in a GAS line. In one case a poor weld in the drain system broke after a hydrostatic test carried out in the month of December.

Defective Girth Weld and Construction Damage (DGW + CD)

Construction damage, including dents, buckles, and gouges which impinge on girth welds represent a more severe condition than if they affected the pipe body. This is due to 1) the weld acting as a geometric stress concentration and 2) the possibility for flaws to exist in the girth weld. The DGW + CD interaction accounted for one case in HL lines and another in GAS lines; the case in GAS lines was classified as DGW + CD + EM and the narrative reports the rupture was caused by weld imperfections at a girth weld and soil conditions caused by a previous excavation.

Defective Girth Weld and Malfunction of Control and Relief Equipment (DGW + MCRE)

There would seem to be little chance of interaction between the threat of defective girth weld and the threat associated with control and relief equipment failure because girth welds are used primarily to join segments of line pipe while pressure control and relief equipment failure is associated primarily with components including pumps, valves and instrumentation piping. The DGW + MCRE interaction accounted for one incident in the GAS lines; a malfunctioning control equipment allowed LNG into 10" steel pipeline causing thermal contraction that broke a girth weld.

Defective Girth Weld and Threads Stripped, Broken Pipe, or Coupling (DGW + TSBPC)

There is no perceived interaction between the threat of defective girth weld and the threat associated with stripped threads or coupling failure because girth welds are used as an alternative to threaded joints or coupled joints. No incidents with DGW + TSBPC were encountered.

Defective Girth Weld and Gasket Failure (DGW + GF)

There is no perceived interaction between the threat of defective girth weld and the threat of gasket failure because gaskets are associated with an alternative joint type (*e. g.*, flanged connections) to welded joints. No incidents with DGW + GF were encountered.

Defective Girth Weld and Seal or Pump Packing Failure (DGW + SPPF)

There is no perceived interaction between the threat of defective girth weld and the threat of seal or pump packing failure because girth welds are used primarily to join segments of line pipe while seals and pump packing failure is associated primarily with components including pumps, valves, and instrumentation piping. No incidents with DGW + SPPF were encountered.

Defective Girth Weld and Incorrect Operation (DGW + IO)

Girth welds generally are not affected by operations or maintenance. Still, the DGW + IO interaction accounted for five incidents in HL lines (Table B-20) and one incident in a GAS line. Three of the HL cases were caused by bending or excessive vibration.

Table B-20. DGW + IO Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
20100294	HL	DGW	IO		Inadequate weld penetration; stress concentrator.	
20130341	HL	DGW	IO		Pinhole in defective weld. Incompatible service.	
20130365	HL	DGW	IO		HAZ cracking and slag inclusion; ineffective repair	
20150040	HL	DGW	IO		Defective weld; misalignment; bending stress	
20150076	HL	DGW	IO		Residual bending stress at weld; vibration	

Defective Girth Weld and Third Party Damage (DGW + TP)

The probability of a defective girth weld leading to an immediate failure from mechanical damage is considered to be less likely than an immediate failure in the body of the pipe because of there is more area of exposure associated with the pipe than with the girth welds. The DGW + TP interactions accounted for two incidents in the GAS lines; one narrative reports a crack in a weld that was affected by a blast and the other reports multiple successive hits on a line that bent and broke the line at a crack defect.

Defective Girth Weld and Previously Damaged Pipe (DGW + PDP)

Latent mechanical damage (*e. g.*, dents or gouges) affecting a girth weld is considered to be more significant than the same degree of damage in the body of the pipe. This is due to 1) the weld acting as a geometric stress concentration and 2) the possibility for flaws to exist in the girth weld. With changes in pressure or axial stress over time, a defective girth weld contained within a dent could lead to the development of a leak or a rupture. However, no incidents with DGW + PDP were encountered.

Defective Girth Weld and Vandalism (DGW + V)

The probability of a defective girth weld leading to an immediate failure from vandalism is considered to be no more likely than an immediate failure in the body of the pipe. No incidents with DGW + V were encountered.

Defective Girth Weld and Earth Movement (DGW + EM)

Soil movement, such as subsidence or landslides, results in an increase in the axial force applied to a pipeline. Defects in a girth weld could be susceptible to failure from the high axial stress even though they may not be critical at the axial stress levels associated with internal pressure (0.3 times hoop stress in a buried pipeline). In fact, many failures associated with earth movement consist of girth weld separation.

The DGW + EM interaction accounted for 10 incidents in HL lines (Table B-21) and 19 incidents in GAS lines (Table B-22). All narratives report pipeline displacement because of soil subsidence or lateral spread and failure at a defective girth weld.

Table B-21. DGW + EM Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19860184	HL	DGW	EM	MISC	Bottom erosion caused failure of defective weld	Current drag
19900004	HL	DGW	EM		Soil subsidence cracked defective weld	Clay consolidation
19910189	HL	DGW	EM		Soil subsidence cracked defective weld	River bank
20000012	HL	DGW	EM		Soil subsidence cracked defective weld	Erosion/compactation
20040045	HL	DGW	EM	HRF	Trench collapse cracked defective weld	Excavation
20080019	HL	DGW	EM		Circumferential cracking caused by soil subsidence	Unclear if GW
20090163	HL	DGW	EM	HRF	Landslide broke weld with incomplete penetration	
20120023	HL	DGW	EM		Soil subsidence cracked defective weld	Sinkhole
20130182	HL	DGW	EM		Soil subsidence cracked defective weld	
20140097	HL	DGW	EM	CW	Soil movement cracked defective weld	Thawing/heave

Table B-22. DGW + EM Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19841073	Gas	DGW	EM		Rupture of a girth weld caused by soil subsidence	
19850050	Gas	DGW	EM		Soil subsidence, failed at a weld	
19860126	Gas	DGW	EM		Landslide failed a girth weld	
19880159	Gas	DGW	EM		Mudslide caused pipe to fail at a defective girth weld	
19930055	Gas	DGW	HRF	EM	Landslide, caused pipe to fail at girth weld	
19950071	Gas	DGW	EM	HRF	Landslide failed several girth welds	
19970050	Gas	DGW	EM	CW	Soil settlement and frostheave caused DGW to fail	
19850312	Gas	DGW	EM		Incomplete girth weld separated due to subsidence	
20060013	Gas	DGW	EM		Soil subsidence, pre-existing underbead cracking	
20060036	Gas	DGW	EM		Defective girth weld failed by probable subsidence	
20060040	Gas	DGW	EM		Girth weld had underbead cracks stressed by subsidence	
20060141	Gas	DGW	EM		Weld failed from excessive stress on offshore line	
20070015	Gas	DGW	EM		Girth weld less than top quality workmanship	
20080028	Gas	DGW	EM	CD	Weld imperfections at girth weld and soil movement	
20080039	Gas	DGW	EM		Poorly completed welding failed due to soil instability	
20090121	Gas	DGW	EM		Soil movement, girth weld fractured	
20130040	Gas	DGW	EM		Bending stresses on defective girth weld	
20140017	Gas	DGW	EM		Defective girth weld failed by probable subsidence	
20140021	Gas	DGW	EM		Overstress of girth weld with lack of fusion	

Very lean low-carbon high strength steel is commonly manufactured by thermal mechanical controlled processing, typically with additions of Ti, Nb, or Ti + V producing fine-grained microstructures with SMYS in the 60 to 80 ksi range. It has been shown with such steels that softening of the HAZ adjacent to the girth weld may occur during the welding and cooling process, depending on the parameters of welding [51]. Conventional practice encourages producing welds in which the deposited weld metal overmatches the base metal. Overmatching of the deposited weld also leads to the greatest HAZ softening effect. Elevated transition temperatures in the HAZ may accompany such softening. Overmatching welds can concentrate strain in the softened HAZ and if flaws are present near this zone, cleavage fracture may occur. Fit-up problems that result in high-low across the weld joint may act to further concentrate strain. Welding procedure qualification as practiced in most pipeline construction projects does not test for or detect such effects.

The reduced tolerance for flaws in or adjacent to a softened HAZ may interact with large axial strains induced by soil movement or other geotechnical influences to result in girth weld failures at low axial strain levels. The authors have direct knowledge of girth weld failures in recently-built pipelines constructed using modern, lean-chemistry high-strength line pipe welded conventionally and subjected to geotechnical loadings, in which HAZ softening was present and appeared to play a significant role.

Defective Girth Weld and Heavy Rains and Floods (DGW + HRF)

External loads from heavy rains and floods, namely scouring of backfill, floating, and vortex shedding in water current create an axial stress in the pipeline that can be much greater than the axial stress associated with internal pressure. The effect on girth welds and mechanical couplings is similar to that described under defective girth welds and earth movement above.

The DGW + HRF interactions accounted for seven incidents in HL lines (Table B-23) and 11 incidents in GAS lines (Table B-24). Six incidents were caused by the pipeline being exposed to river/flooding currents. A similar number of incidents were caused by the line being exposed to high winds and tidal surge from hurricanes.

Table B-23. DGW + HRF Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19890084	HL	DGW	HRF		Debris and current cracked defective weld	Not API1104 compliant
20040270	HL	DGW	HRF		Hurricane forces cracked defective weld	
20040291	HL	DGW	HRF		Hurricane forces cracked defective weld	
20050028	HL	DGW	HRF		Hurricane forces cracked defective weld	
20050073	HL	DGW	HRF		Flooding forces broke defective weld	
20060048	HL	DGW	HRF		Hurricane forces cracked defective weld	
20130276	HL	DGW	HRF	EM	Landslide cracked line at defective weld	

Table B-24. DGW + HRF Interactions for GAS Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19920125	Gas	DGW	HRF		Break at a girth weld after being exposed to currents	
19930055	Gas	DGW	HRF	EM	Landslide, caused pipe to fail at girth weld HAZ	
19930109	Gas	DGW	HRF		River scour, pipeline failed at girth weld HAZ	
19940018	Gas	DGW	HRF		Scoured pipeline cover, failure of girth weld	
19970047	Gas	DGW	HRF	CW	Girth weld failure "possibly due to ice flow in river"	
20040090	Gas	DGW	HRF		Hurricane Ivan failed pipeline at subsea tie-in (DGW?)	
20040091	Gas	DGW	HRF	TP	Anchor damage at subsea tie-in	
20080059	Gas	DGW	HRF		River scour, pipeline failed at girth weld HAZ	
20090014	Gas	DGW	HRF		Tie-in weld leaked because of Hurricane Ike	
20090058	Gas	DGW	HRF		Break at a girth weld after being exposed to currents	
20040059	Gas	DGW	HRF		River flooded, caused pipeline to fail at GW	

Defective Girth Weld and Lightning (DGW + LIGHT)

There is no apparent interaction between defective girth welds and lightning. No incidents with DGW + LIGHT were encountered.

Defective Girth Weld and Cold Weather (DGW + CW)

Girth weld failures have been known to have occurred at low temperatures (*e. g.*, well below the transition temperature of the metal). Many of these were associated with acetylene girth welds which tend to behave in a very brittle manner. While axial stress, possibly from earth movement as well as from restrained thermal contraction probably played a role in these failures, it is felt that there is a possibility of interaction between poor quality girth welds and cold weather.

The DGW + CW interaction accounted for one incident in an HL line and two incidents in GAS lines. The narratives only report that a defective girth weld failed during below-freezing temperatures.

Construction Damage and Malfunction of Control and Relief Equipment (CD + MCRE)

The threat of construction damage is considered to interact with the threat of malfunction of control and relief equipment as explained previously under External Corrosion (and other causes) and Malfunction of Control or Relief Equipment if the pipeline has not been subjected to a prior pressure test to a pressure level of at least 1.25 times the MAOP. No incidents with CD + MCRE were encountered.

Construction Damage and Threads Stripped, Broken Pipe or Coupling (CD + TSBPC)

Cross threaded connections or small piping which has been struck or bent during installation is likely to fail in service. The CD + TSBPC interaction accounted for one incident in an HL line and two incidents in GAS lines. One corresponds to a threaded coupling damaged during construction, but two others are related to a Dresser coupling failing after line modifications.

Construction Damage and Gasket Failure (CD + GF)

Assembly of flanges is considered under incorrect operations, so no interaction of construction damage and gasket failure is assumed. No incidents with CD + GF were encountered.

Construction Damage and Seal and Pump Packing Failure (CD + SPPF)

Assembly of machinery components is considered under incorrect operations, so no interaction of construction damage and seal or pump packing failure is assumed. No incidents with CD + SPPF were encountered.

Construction Damage and Incorrect Operations (CD + IO)

Construction damage and incorrect operations were initially assumed to be mutually exclusive. Still, one incident with CD + IO interaction was observed in an HL line. The leak occurred when a line with a dent was accidentally over pressurized.

Construction Damage and Third Party Damage (CD + TP)

While construction damage and third party damage can have similar adverse effects on pipelines, they are mutually exclusive and cannot constitute interacting threats. No incidents with CD + TP were encountered.

Construction Damage and Previously Damaged Pipe (CD + PDP)

Construction damage and previously damaged pipe (latent third party damage) are mutually exclusive and cannot constitute an interacting threat. No incidents with CD + PDP were encountered.

Construction Damage and Vandalism (CD + V)

Construction damage and vandalism are mutually exclusive and cannot constitute an interacting threat. No incidents with CD + V were encountered.

Construction Damage and Earth Movement (CD + EM)

There is a likelihood of interaction between the threat of construction damage and the threat of earth movement. CD + EM interaction accounted for four incidents in HL lines (Table B-25) and three incidents in GAS lines. All four incidents in HL lines are classified as CD + EM + CW and the terrain movement was due to frost heave.

Table B-25. CD + EM Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19880177	HL	CD	EM	CW	Pipe resting on rock; movement due to frost heave	
19940135	HL	CD	EM	CW	Pipe resting on rock; movement due to frost heave	
20030234	HL	CD	EM	CW	Pipe resting on rock; movement due to frost heave	
20030269	HL	CD	EM	CW	Pipe resting on rock; movement due to frost heave	

Construction Damage and Heavy Rains and Floods (CD + HRF)

There is some likelihood of interaction between the threat of construction damage and the threat of heavy rains and floods. One CD + HRF incident in a GAS pipeline was observed in which a wrinkle in a bend was overstressed by river currents.

Construction Damage and Lightning (CD + LIGHT)

There is no significant interaction between the threat of construction damage and the threat of lightning. No incidents with CD + LIGHT were encountered.

Construction Damage and Cold Weather (CD + CW)

There is some interaction between the threat of construction damage and the threat of cold weather. CD + CW interactions were observed in four incidents in HL lines. They were classified as CD + EM + CW and are presented in Table B-25 shown above in conjunction with CD + EM incidents. No incidents in GAS lines were caused by the CD + CW interaction.

Malfunction of Control or Relief Equipment and Thread Stripped, Broken Pipe, or Coupling (MCRE + TSBPC)

The threat of MCRE could interact with stripped threads and couplings if over-pressure can cause leakage at these components. This interaction accounted for five incidents in GAS lines (Table B-26). In most cases a supply gas tubing of the relief valve is damaged and causes the relief equipment to malfunction.

Table B-26. MCRE + TSBPC Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19841099	Gas	MCRE	TSBPC		Nipple failed on compressor, valve damaged	
20040058	Gas	MCRE	TSBPC		Nipple failed on compressor, relief equipment damaged	
20070102	Gas	MCRE	TSBPC		Controlling tube failure; unintended pressure relief	
20110383	Gas	MCRE	TSBPC		Supply gas tubing failed preventing relief valve to seat	
20130027	Gas	MCRE	TSBPC		Controlling tube failure; unintended pressure relief	

Malfunction of Control or Relief Equipment and Gasket Failure (MCRE + GF)

The threat of MCRE could interact with gaskets if over-pressure can cause leakage at these components. The MCRE + GF interaction accounted for one incident in an HL line and four incidents in GAS lines. In most cases a failed O-ring on a valve caused an emergency shutdown (ESD) valve or relief equipment to activate.

Malfunction of Control or Relief Equipment and Seal or Pump Packing Failure (MCRE + SPPF)

The threat of MCRE could interact with seals or pump packing if over-pressure can cause leakage at these components. MCRE + SPPF interaction accounted for one incident in an HL line and one incident in a GAS line.

Malfunction of Control or Relief Equipment and Incorrect Operation (MCRE + IO)

The threats of MCRE and IO interact to the extent that lack of control of the process combined with a malfunction of the relief or ESD system can result in a loss of containment. Another possible scenario is a valve failing to operate while the operator remains unaware leading to overpressure of a segment of the line. MCRE + IO interaction accounted for 18 incidents in HL lines (Table B-27) and 11 incidents in GAS lines (Table B-28). Nine incidents in HL lines and three incidents in GAS lines were caused by a valve failure followed by the operator's failure to notice the anomalous condition or failure to shutdown/isolate the section affected. Four incidents in HL lines and seven incidents in GAS lines were caused by an incorrect transient operation which resulted in a valve being in wrong position followed by a malfunction of the ESD valve or relief equipment (generally a relief valve not seating).

Table B-27. MCRE + IO Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19850146	HL	MCRE	IO		Wrongly automatic close up; control valve blockage.	
19900151	HL	MCRE	IO		Relief valve failed; high sump alarm failed.	
19940040	HL	MCRE	IO		Pump failed to start; two valves malfunctioned.	No root cause details
19990055	HL	MCRE	IO		Valve malfunction; valve indicator malfunctioned.	
20060339	HL	MCRE	IO		Valve failure; personnel communication problem.	
20090077	HL	MCRE	IO		Valve failure; personnel communication problem.	
20090264	HL	MCRE	IO		Relief valve error; opertator error.	lack of details
20090302	HL	MCRE	IO		Tank gauge failed; alarm failed; deficient response.	Procedure reviewed
20100131	HL	MCRE	IO		Relief valve error; alarms failure	
20110160	HL	MCRE	IO		Failed diaphragm due to material incompatibility	Replaced
20120368	HL	MCRE	IO		Overpresure; relief valve level switch malfunction	
20130228	HL	MCRE	IO		Leaking pressure gauge for low pressure service	
20140149	HL	MCRE	IO		MOV failed to close - procedure not followed	
20140351	HL	MCRE	IO		Simultaneous valve closure; relief valve did not open	
20140411	HL	MCRE	IO		Valve leaked oil to drain; drain valve left open	
20150069	HL	MCRE	IO		Relief valve set screw leaked during inspection	Unclear if IO
20150181	HL	MCRE	IO		Valve failed; pressure relief; vibration broke nipple	Vibration addressed
20150276	HL	MCRE	IO		Pressure comeback; Relief valve stuck due to debris	TP pumps failed

Table B-28. MCRE + IO Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19860112	Gas	MCRE	IO		Accidental flow increase; relief failed to open.	
20050153	Gas	MCRE	IO		Faulty thermocouple in MCRE; thermal expansion	
20100004	Gas	MCRE	IO		Valve solenoid failed. PLC failed to start shutdown	
20100005	Gas	MCRE	IO		Debris on ESD valve actuator; PLC missed ESD alarm	
20100022	Gas	MCRE	IO		Communication error; ESD valves failed to open	
20110397	Gas	MCRE	IO		Unintended overpressure; relief valve did not seat	
20120027	Gas	MCRE	IO		Incorrect isolation procedure; valve actuator failed	
20130009	Gas	MCRE	IO		Accidental operation of block valve; system relief	
20130035	Gas	MCRE	IO		Relief valve fitting boke by fatigue; unintended relief	
20130050	Gas	MCRE	IO		Instrumentation fail. ESD discharge valve did not close	
20150005	Gas	MCRE	IO		Failure to control valve closure; backup system failed	

Malfunction of Control or Relief Equipment and Third Party Damage (MCRE + TP)

Any protrusions from the line are at risk of being impacted during excavation work, particularly when the excavator is digging parallel to an existing pipeline with a backhoe. Small diameter valves are particularly susceptible to breaking from direct impacts. MCRE + TP interaction accounted for three incidents in HL lines and two incidents in GAS lines. All cases report backhoes pushing rocks or hitting a valve.

Malfunction of Control or Relief Equipment and Previously Damaged Pipe (MCRE + PDP)

There is no significant interaction between the threat of malfunction of control or relief equipment and the threat of previously damaged pipe. No incidents with MCRE + PDP were encountered.

Malfunction of Control or Relief Equipment and Vandalism (MCRE + V)

There is no significant interaction between the threat of malfunction of control or relief equipment and the threat of vandalism. No incidents with MCRE + V were encountered.

Malfunction of Control or Relief Equipment and Earth Movement (MCRE + EM)

There is some interaction between the threat of malfunction of control or relief equipment and the threat of earth movement. One incident in a GAS line was cause by a MCRE + EM interaction.

Malfunction of Control or Relief Equipment and Heavy Rains or Floods (MCRE + HRF)

There is some interaction between the threat of malfunction of control or relief equipment and the threat of heavy rains and floods. MCRE + HRF interaction accounted for five incidents in GAS lines (Table B-29). Three of those incidents happened during a hurricane.

Table B-29. MCRE + HRF Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
20050130	Gas	MCRE	HRF		Relief valve cracked opened due to hurricane	
20080091	Gas	MCRE	HRF		Hurricane damaged control tubing	
20080092	Gas	MCRE	HRF		Floating debris separated tubing from controls	
20080103	Gas	MCRE	HRF		Hurricane caused needle valve to shear	
20080106	Gas	MCRE	HRF		Tubing in meter station was severed	

Malfunction of Control or Relief Equipment and Lighting (MCRE + LIGHT)

Power outages during lighting storms can combine with faulty ESD valves or relief equipment to cause loss of containment. MCRE + LIGHT interaction accounted for one incident in an HL line and seven incidents in GAS lines (Table B-30). In five incidents the line shutdown failed because of a malfunctioning MCRE after a power outage.

Table B-30. MCRE + LIGHT Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19900113	Gas	MCRE	LIGHT		Power outage, ESD failed to operate the suction valve	
20040060	Gas	MCRE	LIGHT		DC charge that triggered ESD, valves hung open	
20050077	Gas	MCRE	LIGHT		Lightning damaged relief equipment	
20060009	Gas	MCRE	LIGHT	SPPF	Needle valve orifice out of adjustment	
20070101	Gas	MCRE	LIGHT		Lightning strike caused MCRE upset; closure failed	
20080065	Gas	MCRE	LIGHT		3rd party transformer exploded; controller damaged	
20140101	Gas	MCRE	LIGHT	IO	Power outage. Emergency shutdown failed.	

Malfunction of Control or Relief Equipment and Cold Weather (MCRE + CW)

Water entrapped in a valve body or instrumentation tubing can freeze and impede valve closure. In addition, condensation of water avgas line can occur when it is operating below the dew point of the mixture. Water is particularly detrimental to the operation of relief devices. The MCRE + CW interaction accounted for 27 incidents in HL lines (Table B-31) and 33 interactions in GAS lines (Table B-32). Ten of the incidents in HL lines are classified as MCRE + CW + IO, because incorrect operation or maintenance facilitated water or debris entrapment inside the valve. Twenty incidents in GAS lines report a frozen regulator malfunction.

Table B-31. MCRE + CW Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19900017	HL	MCRE	CW	IO	Water entrapped inside valve; ice cracked valve.	
19910020	HL	MCRE	CW	IO	Residual water trapped inside valve; ice cracked valve	Hydrostest water
19910058	HL	MCRE	CW	IO	Water trapped inside valve; ice cracked valve	
19940114	HL	MCRE	CW		Freezing temperatures damaged valve	No details
19970006	HL	MCRE	CW		Freezing temperatures damaged valve	No details
19970035	HL	MCRE	CW	IO	Water trapped inside valve; ice cracked valve	
20010028	HL	MCRE	CW	IO	Water trapped inside valve; ice cracked valve	Gasket failure
20020026	HL	MCRE	CW		Ice forming inside relief device	
20050063	HL	MCRE	CW		Overpressurisation caused by ice plug; valve failure.	
20070069	HL	MCRE	CW		Freezing temperatures damaged valve	No details
20100025	HL	MCRE	CW		Valve failed to seal due to ice formation	
20100255	HL	MCRE	CW		Relief valve failed to open due to ice formation	
20110101	HL	MCRE	CW		Water trapped inside valve; ice cracked valve	
20120044	HL	MCRE	CW		Water trapped inside valve; ice cracked valve	
20130047	HL	MCRE	CW		Water trapped inside valve; ice cracked valve	Hydrostest water
20130137	HL	MCRE	CW	IO	Valve cracked due to freeze/thaw cycles and debris	
20140002	HL	MCRE	CW	IO	Relief valve failed to open due to ice formation	
20140015	HL	MCRE	CW	IO	Premature relief due to cold weather and debris	
20140035	HL	MCRE	CW		Ice plug prevented seal leak shutdown from working	
20140262	HL	MCRE	CW		Premature relief due to cold weather	
20140299	HL	MCRE	CW	IO	Frostheave broke valve threaded connection	Replaced/redesigned
20140425	HL	MCRE	CW		Water trapped inside valve; ice cracked valve	
20150045	HL	MCRE	CW		Frostheave broke valve threaded connection	
20150049	HL	MCRE	CW	IO	Premature relief due to cold weather and debris	
20150050	HL	MCRE	CW		Valve damaged by cold weather	No details
20150052	HL	MCRE	CW		Water trapped inside valve; ice cracked valve	
20150082	HL	MCRE	CW		Drain line froze; MOV seal failed; oil backed up	

Table B-32. MCRE + CW Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19940040	Gas	MCRE	CW		Cold weather caused a regulator to freeze off	
19970030	Gas	MCRE	CW		Gas below dew point, regulator malfunction	
20040017	Gas	MCRE	CW		Liquids in line froze, preventing relief valve closure	
20040025	Gas	MCRE	CW		Moisture in the control line froze, cause CRE to fail.	
20060026	Gas	MCRE	CW		Gas below dew point, regulator malfunction	
20070016	Gas	MCRE	CW		Gas below dew point, regulator malfunction	
20070042	Gas	MCRE	CW		Regulator failed open caused by ice in pilot.	
20080045	Gas	MCRE	CW		Regulator froze causing relief valve to vent.	
20080149	Gas	MCRE	CW	IO	Gas below dew point, regulator malfunction	Heating failure
20090015	Gas	MCRE	CW		Gas below dew point, regulator malfunction	
20090021	Gas	MCRE	CW	IO	Controller fail due to CW	
20100008	Gas	MCRE	CW		Gas pressure regulator was iced over	
20100087	Gas	MCRE	CW		Cold weather froze flanged end of valve above soil	
20130005	Gas	MCRE	CW		Supply gas line froze; blowdown valve opened	
20130014	Gas	MCRE	CW		Sensing line tubing froze, cause premature relief	
20130113	Gas	MCRE	CW		Blowdown valve pilot pressure switch froze	
20140007	Gas	MCRE	CW		Partial freeze of the ESD system	
20140009	Gas	MCRE	CW		Blowdown improper operation because of freeze off	
20140014	Gas	MCRE	CW		ESD system sensor froze and malfunctioned	
20140016	Gas	MCRE	CW		Relief equipment instrumentation froze	
20140025	Gas	MCRE	CW		Freezing rain caused icing on a poppet block	
20140026	Gas	MCRE	CW		Relief equipment instrumentation froze	
20140029	Gas	MCRE	CW		Pilot sensing line froze and caused premature relief	
20140031	Gas	MCRE	CW		Vent on the control pilot froze	
20140053	Gas	MCRE	CW		Blowdown valve pilot pressure switch froze	
20140144	Gas	MCRE	CW		Valve did not close because of freeze off	
20110020	Gas	MCRE	CW		Gas pressure regulator was iced over	
20150011	Gas	MCRE	CW		RV regulators froze	Heaters moved away
20150016	Gas	MCRE	CW		Frost in the body of RV; unintended release	
20150020	Gas	MCRE	CW		Pilot sensing line froze; unintended RV aperture	
20150036	Gas	MCRE	CW		Pilot sensing line froze; unintended RV aperture	
20150046	Gas	MCRE	CW		Hydrates freezing in pilot line; unintended relief	

Threads Stripped, Broken Pipe, or Coupling and Gasket Failure (TSBPC + GF)

There is some interaction between the threat of threads stripped, broken pipe or coupling and the threat of gasket failure. The TSBPC + GF interaction accounted for two incidents in HL lines. In one case the incident was a combination of a valve with a defective gasket and a failure of a threaded connection to the drain.

Threads Stripped, Broken Pipe, or Coupling and Incorrect Operations (TSBPC + IO)

Improper installation of threaded joints is a primary cause of stripped threads. Dresser couplings when properly installed in competent soil tend to perform adequately with respect to hoop stress loads. However, if the soil load is compromised, such as by erosion of the cover or by settlement, these joints are susceptible to pull-out failure. The axial load required to pull

pipe from within a Dresser coupling is relatively low. If the pipeline is installed with misalignment of the pipes at couplings or deliberate angle changes at couplings, the line is less able to withstand soil movement. TSBPC + IO interaction accounted for 47 incidents in HL lines (Table B-33) and seven incidents in GAS lines (Table B-34). Twenty-six (26) of the 47 incidents in HL lines had the coupling or fitting or connection replaced or redesigned, which indicates faulty design. Nine incidents had issues with the installation of the connection/coupling/fitting. Twenty-seven of the 47 incidents in HL lines were associated with excessive vibration or thermal expansion.

Table B-33. TSBPC + IO Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19870173	HL	TSBPC	IO		Small diam. nipple cracked due to excessive vibration	Replaced/Redesigned
19890134	HL	TSBPC	IO		Threaded plug became loose due to vibration	Replaced/Redesigned
19900018	HL	TSBPC	IO		Dresser coupling on discharge side slided apart.	
19910029	HL	TSBPC	IO		Stuck cap; excessive leverage broke nipple.	
19930010	HL	TSBPC	IO		Excessive overburden loading stressed scewed fitting	Removed
19930031	HL	TSBPC	IO		Thread-a-let cracked due to excessive vibration	
19940104	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
19940111	HL	TSBPC	IO		Small diam misaligned threading leaked.	
19950077	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	
19960026	HL	TSBPC	IO		Threaded fitting failed (no root cause detail)	Replaced/Redesigned
19980066	HL	TSBPC	IO		Dresser coupling overstressed. Lack of support.	
19990149	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
20020078	HL	TSBPC	IO		Mechanical repair sleeve not completely tight	
20020083	HL	TSBPC	IO		Bolts with improper length installed at meter	Replaced/Redesigned
20020314	HL	TSBPC	IO		Unmapped clamp not completely tight	
20030320	HL	TSBPC	IO		Lateral restraint removed; Dresser coupling shifted	
20040004	HL	TSBPC	IO		Threaded nipple sheared due to excessive vibration	Replaced/Redesigned
20040007	HL	TSBPC	IO		Threaded nipple sheared due to excessive vibration	Replaced/Redesigned
20040018	HL	TSBPC	IO		Threaded nipple sheared due to excessive vibration	Replaced/Redesigned
20040226	HL	TSBPC	IO		Cap vibrated loose over time.	
20060091	HL	TSBPC	IO		Threaded nipple sheared due to excessive vibration	
20070275	HL	TSBPC	IO		Threaded tubing failed due to excessive vibration	
20080012	HL	TSBPC	IO		Accidental overpressurisation; drain nipple failure.	No details
20090042	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	
20090057	HL	TSBPC	IO		Threaded tubing failed due to excessive vibration	Replaced/Redesigned
20090101	HL	TSBPC	IO		Tubing failed due to low stress high cycle vibration	Removed
20090102	HL	TSBPC	IO		Thermal stress deteriorated bolts	Replaced/Redesigned
20090186	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
20090292	HL	TSBPC	IO		Bending stress and poor material properties	Replaced/Redesigned
20110005	HL	TSBPC	IO		Threaded fitting failed due to vibration/expansion	
20110077	HL	TSBPC	IO		Threaded fitting failed due to vibration/expansion	Replaced/Redesigned
20110401	HL	TSBPC	IO		Bent/misaligned nipple cracked due to vibration	
20110419	HL	TSBPC	IO		Dresser coupling w/o long. Anchorage + overpressure	
20120196	HL	TSBPC	IO		Nipple leak. No alarm downstream of meter skid.	
20130029	HL	TSBPC	IO		Threaded connection failed. Procedures omitted.	
20130067	HL	TSBPC	IO		Wrong fitting installed	Replaced/Redesigned
20140048	HL	TSBPC	IO		Connection misalignment and overpressure.	
20140213	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
20140334	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
20140363	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
20140417	HL	TSBPC	IO		Overtightening of fitting and/or bending.	
20150102	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
20150186	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
20150203	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
20150204	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
20150226	HL	TSBPC	IO		Threaded fitting cracked due to excessive vibration	Replaced/Redesigned
20150472	HL	TSBPC	IO		Threaded fitting cracked due to vibration/expansion	Replaced/Redesigned

Table B-34. TSPBC + IO Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19920192	Gas	TSBPC	IO		Dresser coupling pulled out after making replacement	
19940029	Gas	TSBPC	IO		Dresser coupling pulled out after making modifications	
19960110	Gas	TSBPC	IO		Dresser coupling pulled out after making modifications	
19930192	Gas	TSBPC	IO		Dresser coupling pulled out while making repairs nearby	
20090016	Gas	TSBPC	IO		Incomplete engagement by the slip anchor	
20140107	Gas	TSBPC	IO		Coupling was exposed during excavation; later separated	

Threads Stripped, Broken Pipe, or Coupling and Third Party Damage (TSBPC + TP)

Any protrusions from the line are at risk of being impacted during excavation works, particularly when the excavator is digging parallel to an existing pipeline with a backhoe. Small diameter fittings and connections are particularly susceptible to breaking from direct impacts or compaction of soil on top of them. TSBPC + TP interaction accounted for 36 incidents in HL lines (Table B-35) and 11 incidents in GAS lines (Table B-36). Twenty-six (26) of the 36 incidents in HL lines and five of the 11 incidents in GAS lines were impacts to buried or partially covered protrusions. If the protrusion was unmapped, then the incident is classified as TSBPC + TP + IO. In three incidents, the backhoe did not hit the protrusion directly, but displaced a rock or compacted the soil on top of the protrusion. In nine incidents in HL lines and five incidents in GAS lines, the protrusion was above ground or was already uncovered. In the majority of cases the contractor hit the protrusion because he was operating equipment too close to the pipe.

Table B-35. TSBPC + TP Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19860190	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19870202	HL	TSBPC	TP		Equipment hit partially covered protusion	
19880152	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19880182	HL	TSBPC	TP		Backhoe brushed small diameter protusion	Not covered
19890095	HL	TSBPC	TP		Backhoe brushed small diameter protusion	Not covered
19890107	HL	TSBPC	TP		Contractor brushed small diameter protusion	Not covered
19890151	HL	TSBPC	TP		Contractor ran over small diameter protusion	Not covered
19900159	HL	TSBPC	TP	IO	Buried small diameter protusion hit by excavator	ILI misinterpretation
19910068	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19910109	HL	TSBPC	TP		Backhoe brushed small diameter protusion	Not covered
19920013	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19920029	HL	TSBPC	TP		Buried protusion hit by excavator	Unauthorized tap
19930229	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19940206	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	Indirect hit
19950003	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19950147	HL	TSBPC	TP		n/a	No details
19950195	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19960105	HL	TSBPC	TP		Contractor brushed small diameter protusion	Not covered
19970158	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19980098	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19980101	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19980102	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19980134	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19990008	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
19990033	HL	TSBPC	TP		Technician fell on top of small diameter protusion	Not covered
19990043	HL	TSBPC	TP	IO	Buried small diameter protusion hit by excavator	Unmapped
19990063	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
20000051	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
20000056	HL	TSBPC	TP	IO	Backhoe slid down incline and hit protusion	
20020008	HL	TSBPC	TP		Buried small diameter protusion hit by excavator	
20020085	HL	TSBPC	TP	IO	Buried small diameter protusion hit by equipment	Indirect hit
20020122	HL	TSBPC	TP	IO	Buried small diameter protusion hit by excavator	Unmapped
20020224	HL	TSBPC	TP	IO	Buried small diameter protusion hit by excavator	Unmapped
20030414	HL	TSBPC	TP	IO	Equipment hit partially covered protusion	
20050055	HL	TSBPC	TP		Manlift basket caught small diameter protusion	
20120313	HL	TSBPC	TP	HRF	Hurled object broke small diameter fitting	

Table B-36. TSBPC + TP Interactions for Gas Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19850208	Gas	TSBPC	TP		Buried small diameter protusion hit by excavator	Indirect hit
20070037	Gas	TSBPC	TP		Cattle rubbed on a small diam threaded vent valve	
19870212	Gas	TSBPC	TP		Buried small diameter protusion hit by excavator	
20040016	Gas	TSBPC	TP		Vehicle crashed into above ground valve	
20040098	Gas	TSBPC	TP		Contractor brushed small diameter protusion	Not covered
20050068	Gas	TSBPC	TP		Buried small diameter protusion hit by excavator	
20050108	Gas	TSBPC	TP		Contractor brushed small diameter protusion	Not covered
20050108	Gas	TSBPC	TP		Contractor brushed small diameter protusion	Not covered
20090033	Gas	TSBPC	TP		Buried small diameter protusion hit by excavator	
20100074	Gas	TSBPC	TP		Buried small diameter protusion hit by excavator	

Threads Stripped, Broken Pipe, or Coupling and Previously Damaged Pipe (TSBPC + PDP)

There is no significant interaction between the threat of threads stripped, broken pipe or coupling and the threat of previously damaged pipe. No incidents with TSBPC + PDP were encountered.

Threads Stripped, Broken Pipe, or Coupling and Vandalism (TSBPC + V)

There is no significant interaction between the threat of threads stripped, broken pipe or coupling and the threat of vandalism. No incidents with TSBPC + V were encountered.

Threads Stripped, Broken Pipe, or Coupling and Earth Movement (TSBPC + EM)

Dresser couplings act like defective girth welds in that they are susceptible to failure when subjected to axial loads, such as those associated with earth movement and heavy rains and floods. Mechanical couplings provide a pressure seal but offer negligible axial strength (e.g., only friction resistance). Earth movement that imparts axial movement to a pipeline could cause pipe to pull out of mechanical couplings.

TSBPC + EM interaction accounted for 14 incidents in HL lines (Table B-37) and 17 incidents in GAS lines (Table B-38). All cases, except one, report soil subsidence or lateral spread that overstressed a coupling or nipple. Lateral spread may also have an HRF component, and the CW component interacts when the soil movement is caused by frost heave.

Table B-37. TSBPC + EM Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19900048	HL	TSBPC	EM	CW	Frostheave pushed flanged connection	
19920184	HL	TSBPC	EM		Ground settlement caused coupling separation	
19930014	HL	TSBPC	EM	HRF	Ground shifting due to heavy rains pulled collar	
19960014	HL	TSBPC	EM		Subsidence due to drought pulled collar coupling	
19960015	HL	TSBPC	EM		Subsidence due to drought pulled collar coupling	Double entry?
19980160	HL	TSBPC	EM	HRF	Mudslide event during hurricane separated riser	
20020152	HL	TSBPC	EM		Nipple bent and cracked due to ground pressure	No details
20030162	HL	TSBPC	EM	CW	Nipple bent and cracked due to ground frostheave	
20050252	HL	TSBPC	EM		Planar tilt caused by tank settlement	
20070050	HL	TSBPC	EM	CW	Nipple bent and cracked due to ground frostheave	
20070251	HL	TSBPC	EM	HRF	Ground shifting due to heavy rains pulled collar	
20100064	HL	TSBPC	EM	CW	Nipple bent and cracked due to ground expansion	
20130368	HL	TSBPC	EM		Subsidence due to drought misaligned bolted flange	
20140092	HL	TSBPC	EM	CW	Freezing temperatures and soil movement	No details

Table B-38. TSBPC + EM Interactions for Gas Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19841090	Gas	TSBPC	EM		Dresser coupling leak due to earth movement	
19850208	Gas	TSBPC	EM		8" coupled line, failed from earth compression	Heavy equipment
19880129	Gas	TSBPC	EM	HRF	Landslide; pipe partially slipped out of coupling	
19880227	Gas	TSBPC	EM		Pipe slipped out of coupling	
19890031	Gas	TSBPC	EM	HRF	Earth shift; pipe partially slipped out of coupling	
19890116	Gas	TSBPC	EM		Soil instability; pipe partially slipped out of coupling	
19910182	Gas	TSBPC	EM		Earth shift; pipe slipped out of coupling	
19920192	Gas	TSBPC	EM		Pipe slipped out of coupling	
19960110	Gas	TSBPC	EM		Pipe slipped out of coupling	
19980020	Gas	TSBPC	EM	HRF	Landslide; pipe partially slipped out of coupling	
20060056	Gas	TSBPC	EM		Earth shift; pipe broke at threaded joint	
20060064	Gas	TSBPC	EM		Earth shift; pipe slipped out of coupling	
20090069	Gas	TSBPC	EM		Soil setting caused valve connection to crack	
20090100	Gas	TSBPC	EM		Soil subsidence caused fitting to crack	
20080042	Gas	TSBPC	EM		Fitting cracked from earth compression	Heavy equipment
20140116	Gas	TSBPC	EM		Pipe slipped out of coupling	

Threads Stripped, Broken Pipe, or Coupling and Heavy Rains or Floods (TSBPC + HRF)

Dresser couplings act like defective girth welds in that they are susceptible to failure when subjected to axial loads, such as those associated with earth movement and heavy rains and floods. Mechanical couplings provide a pressure seal but offer only negligible resistance to axial forces, essentially only frictional resistance. Heavy rains and flood events can impart axial forces on pipelines, either by water currents acting on exposed sections of pipeline, or washouts which undermine pipeline support.

TSBPC + HRF interaction accounted for 14 incidents in HL lines (Table B-39) and 18 incidents in GAS lines (Table B-40). At least eight incidents for HL lines and four incidents for GAS lines occurred during a hurricane. One incident happened during a tornado. Six cases involve ground shifting and hence have the EM component.

Table B-39. TSBPC + HRF Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19930014	HL	TSBPC	EM	HRF	Ground shifting due to heavy rains pulled collar	
19980160	HL	TSBPC	EM	HRF	Mudslide event during hurricane separated riser	
20040214	HL	TSBPC	HRF		Discharge valve stuck close; tank overflown	
20040273	HL	TSBPC	HRF		Hurricane forces broke pipe nipple	No details
20040290	HL	TSBPC	HRF		Hurricane forces broke threaded joint	No details
20040336	HL	TSBPC	HRF		Hurricane forces broke coupling	No details
20050284	HL	TSBPC	HRF		Hurricane forces broke threaded fitting	No details
20050285	HL	TSBPC	HRF		Tidal surge floated portable tank and broke fitting	
20050302	HL	TSBPC	HRF		Hurricane forces broke riser	
20060082	HL	TSBPC	HRF		Hurricane forces broke pipe nipple	No details
20070251	HL	TSBPC	EM	HRF	Ground shifting due to heavy rains pulled collar	
20110268	HL	TSBPC	HRF		Rain and misalignment of temporary pig launcher	
20120281	HL	TSBPC	HRF		Wave action and wind displaced valve	
20120313	HL	TSBPC	TP	HRF	Hurled object broke small diameter fitting	

Table B-40. TSBPC + HRF Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19930198	Gas	TSBPC	HRF		Dresser coupling washed out and pulled out	
20050099	Gas	TSBPC	HRF		Tidal surge broke threaded coupling	
20050100	Gas	TSBPC	HRF	DFW	Tidal surge pulled out threaded nipple	
20050104	Gas	TSBPC	HRF		Hurricane damaged a 1" nipple	
20050104	Gas	TSBPC	HRF		Hurricane damaged a 1" nipple	
20050109	Gas	TSBPC	HRF		Control tubing damaged during hurricane	
20050132	Gas	TSBPC	HRF		Damage to 1" bypass line on meter	
20080025	Gas	TSBPC	HRF	EM	Nipple broke from ground settling after flood	
20080071	Gas	TSBPC	HRF		Dresser coupling washed out and pulled out	
20080136	Gas	TSBPC	HRF		Valve and nipple damaged by hurricane	
20090011	Gas	TSBPC	HRF		Washout of supporting soil beneath dresser coupling	
20090028	Gas	TSBPC	HRF	TP	Large tree broke a threaded valve off a threaded riser	
20090065	Gas	TSBPC	HRF	TP	Tree broke a threaded fitting	
19880129	Gas	TSBPC	HRF	EM	Landslide - pipe slipped out of mechanical coupling	
19890031	Gas	TSBPC	HRF	EM	Land shift - pipe slipped out of mechanical coupling	
19980020	Gas	TSBPC	HRF	EM	Coupling washed out and pulled out	
20130023	Gas	TSBPC	HRF	EM	Washout and road collapse.	
20130051	Gas	TSBPC	HRF		Tornado dislodged line from bridge; broken nipple	

Threads Stripped, Broken Pipe, or Coupling and Cold Weather (TSBPC + CW)

The TSBPC + CW interaction accounted for 14 incidents in HL lines (Table B-41) and only three interactions in GAS lines. Five of the incidents in HL lines are classified as TSBPC + EM + CW, and reported a small diameter threaded connection cracked by ground frost heave. Two additional incidents report a flange stressed by frost heave. Five incidents in HL lines simply report that a nipple broke from freezing. Finally, two incidents in HL lines are associated with ice falling from a roof and breaking a small diameter threaded connection; in our experience this scenario is much more significant in the GAS distribution lines, which are not within the scope of this work.

Table B-41. TSBPC + CW Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19900048	HL	TSBPC	EM	CW	Frostheave pushed flanged connection	
19940009	HL	TSBPC	CW		Ice fell from roof and broke nipple connection	
19990017	HL	TSBPC	CW		Pipe nipple failed due to frostheave	Replaced/Redesigned
20020048	HL	TSBPC	CW		Ice fell from roof and broke nipple connection	
20020074	HL	TSBPC	CW		Nipple broke due to freezing	No details
20030162	HL	TSBPC	EM	CW	Nipple bent and cracked due to ground frostheave	
20070050	HL	TSBPC	EM	CW	Nipple bent and cracked due to ground frostheave	
20100064	HL	TSBPC	EM	CW	Nipple bent and cracked due to ground expansion	
20110339	HL	TSBPC	CW		Nipple broke due to freezing	
20130068	HL	TSBPC	CW		Nipple broke due to freezing	
20140085	HL	TSBPC	CW		Frostheave stressed flange mating and gasket	
20140092	HL	TSBPC	EM	CW	Nipple broke due to freezing and ground movement	No details
20150140	HL	TSBPC	CW		Nipple broke due to freezing	
20150297	HL	TSBPC	CW		Nipple bent and cracked due to ground frostheave	Replaced/Redesigned

Gasket Failure and Incorrect Operation (GF + IO)

There is no significant interaction between GF and other threats other than IO. Failures of gaskets are usually attributable to improper selection of the gasket or severe operational conditions or improper installation of the gasket.

GF + IO interaction accounted for 37 incidents in HL lines (Table B-42) and eight incidents in GAS lines (Table B-43). Twenty incidents in HL lines and nine incidents in GAS were caused because of deficient design or wrong specification of the gasket. Nine incidents in HL lines and three incidents in GAS lines report evidence of improper gasket installation. Five incidents in HL lines and one in a GAS pipeline were associated with a defective gasket and incorrect operation of the line/system.

Table B-42. GF + IO Interactions in HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19870032	HL	GF	IO		Defficient check valve design - insufficient sealing	Replaced/redesigned
19870093	HL	GF	IO		Bailed asbesto type gasket failed.	Replaced/redesigned
19870141	HL	GF	IO		Check valve flange failed due to vibration	
19900106	HL	GF	IO		Gasket failure with increased flow	Replaced/redesigned
19900109	HL	GF	IO		Defective fiber gasket	
19920202	HL	GF	IO		Seal failure and pipe cap insufficiently tightened	
19920207	HL	GF	IO		Flange gasket split in two; improper installation	
19930211	HL	GF	IO	MISC	Power outage, overpressurisation and gasket failure	
19950119	HL	GF	IO		Gasket manufacturing defect and not pliable enough	
19950178	HL	GF	IO		Flame arrestor plugged causing gasket failure	
19980092	HL	GF	IO		Leaking gasket and improper line alignment	Replaced/redesigned
19990042	HL	GF	IO		Improper type of O-ring installed	
19990098	HL	GF	IO		Gasket contracted due to cold slug of product	
20000047	HL	GF	IO		Gasket with wrong diameter installed	
20010048	HL	GF	IO		Improper seating of the O-ring	
20010077	HL	GF	IO		Gasket/flange design	No details
20020372	HL	GF	IO		Overheating of seal - inadequate coolant flow	
20020450	HL	GF	IO		Combination of vibration and temperature changes	Replaced/redesigned
20030287	HL	GF	IO		Incorrect flange alignment	Removed
20040196	HL	GF	IO		Defective assembly; defficient procedures	
20040356	HL	GF	IO		Combination of vibration and temperature changes	
20060329	HL	GF	IO		Service incompatibility - chemical deterioration	Replaced/redesigned
20100043	HL	GF	IO		No thermal/pressure relief lead to gasket failure	
20100054	HL	GF	IO		Lack of support & thermal stress. Mechanical defect	
20100097	HL	GF	IO		Gasket out of specification. Lack of variable control	
20110030	HL	GF	IO		Overcomprassion of gasket	
20110374	HL	GF	IO		Improper seating of the O-ring	
20120276	HL	GF	IO		Gasket installed improperly	
20120353	HL	GF	IO		Overcompression and service incompatibility	
20130055	HL	GF	IO		Wrong O-ring specification	Replaced/redesigned
20150038	HL	GF	IO		Wrong O-ring specification	Replaced/redesigned
20150064	HL	GF	IO		Improper installation	No details
20150067	HL	GF	IO		Improper installation	Replaced/redesigned
20150128	HL	GF	IO		Gasket leaking. Suspected low reliability.	Replaced/redesigned
20150187	HL	GF	IO		Service incompability (abrasion)	Replaced/redesigned
20150319	HL	GF	IO		Gasket blew below expected pressure limit	Replaced/redesigned
20150458	HL	GF	IO		Torque didnt consider spec blind spacer + IO	Replaced/redesigned

Table B-43. GF + IO Interactions in GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
20030074	Gas	GF	IO		Sandblasted plastic insulating gasket to failure	
19920025	Gas	GF	IO		Incorrect sealer damaged gasket causing the leak	
20040080	Gas	GF	IO		Incorrect gasket and improperly torqued	
20060034	Gas	GF	IO		Misalignment of nozzles led to gasket failure	
20070059	Gas	GF	IO		Sub-sea assambly shifted causing a flange to leak	
20080047	Gas	GF	IO	EC	Incorrect installation; fretting; minor corrosion.	
20080055	Gas	GF	IO		Damaged o-ring sealfrom improper installation.	
20130008	Gas	GF	IO		Loss of support on flange resulting in cracked gasket	

Seal or Pump Packing Failure and Incorrect Operations (SPPF + IO)

There is no significant interaction between SPPF and other threats other than IO. Improper installation of packing glands can cause early seal failures. Failure to minimize vibrations of small tubing or piping can lead to leaks at joints or fatigue failures of the tubing or piping. The SPPF + IO interaction accounted for seven incidents in HL lines (Table B-44); they either report pump seal failure from excessive vibration/temperature or level alarm failure when the pump seal failed.

Table B-44. SPPF + IO Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19870003	HL	SPPF	IO		Pump seal leaked; failure device & level alarm failed	
19880075	HL	SPPF	IO		Vibration caused metal seating of pump case to wear	Pump not running
20090117	HL	SPPF	IO		Thermal pressure caused idle pump seal to leak	
20090326	HL	SPPF	IO		Vibration failure; vibration and seal leak alarms failed.	
20140368	HL	SPPF	IO		Pump seal leaked; failure device & level alarm failed	
20150075	HL	SPPF	IO		Seal failed from thermal stress; level alarm failed	
20150142	HL	SPPF	IO		Pump seal leaked; failure device & level alarm failed	

Incorrect Operations and Third Party Damage (IO + TP)

Third party damage is defined as an immediate failure resulting from mechanical damage caused by an outside force, such as from contact with excavation equipment. The pipeline industry has developed and implemented procedures for communication and monitoring at locations of known excavation by contractors and land owners. When the pipeline company is properly notified by a one-call system, these procedures are designed to prevent damage and failures resulting from the excavation of the pipeline. Primary responsibilities of the pipeline operator are to respond promptly to a one-call, to see that the pipeline is properly marked and to monitor the excavation activities from start to finish to prevent excavation damage.

There have been failures resulting from excavation activities even after a one-call notification was made. These failures would include, among other things, incidents involving incorrect operations by the pipeline operator personnel. Examples would include failing to make contact with the contractor, improperly locating the pipeline, or improperly hand excavating the pipeline to determine the depth of burial. These would also include incorrect operations performed by the excavation contractor or his personnel.

IO + TP interaction accounted for 24 incidents in HL lines (Table B-45) and seven incidents in GAS lines (Table B-46). Twelve incidents in HL lines and six incidents in GAS lines were associated with the pipeline operator failing to properly mark the pipeline location. Five incidents in HL lines were attributed to one-call issues or communication mistakes. The cause of four incidents in HL lines was the markers were nor preserved or were covered.

Table B-45. IO + TP Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19860134	HL	IO	TP		Operator does not have one call system	
19860166	HL	IO	TP		Construction drawings missing pipeline	
19870212	HL	IO	TP		Markers destroyed by contractor's equipment	
19890002	HL	IO	TP		One call phone number not a working number	
19900095	HL	IO	TP		Markers covered by contractor during ditching	
19910066	HL	IO	TP		Contractor covered markers/stakes	
19980063	HL	IO	TP		Operator notified but failed to mark a line	
19990172	HL	IO	TP		Operator failed to accurately mark pipeline	
19990177	HL	IO	TP		Riser not marked by contractor	
19990181	HL	IO	TP		Operator failed to accurately mark pipeline	
20020254	HL	IO	TP		Contractor hit unidentified riser during ROW marking	
20030298	HL	IO	TP		Operator failed to accurately mark pipeline	Missed by 30'
20040372	HL	IO	TP		Deficient One call system follow up / communication	
20090325	HL	IO	TP		Operator failed to accurately mark pipeline	
20090331	HL	IO	TP		Operator failed to accurately mark pipeline	
20100030	HL	IO	TP		Operator failed to accurately mark pipeline	
20100292	HL	IO	TP		Operator failed to accurately mark pipeline	
20110371	HL	IO	TP		Deficient One call system follow up / communication	
20120220	HL	IO	TP		Contractor deficient excavation practice	IO?
20120286	HL	IO	TP		Communication issue btw operator and contractor	
20140006	HL	IO	TP		Operator failed to accurately mark pipeline	
20140071	HL	IO	TP		Operator failed to accurately mark pipeline	
20150031	HL	IO	TP		Deficient One call system follow up / communication	
20150125	HL	IO	TP		Contractor covered markers/stakes	

Table B-46. IO + TP Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19880002	Gas	IO	TP		Pipeline was improperly located and marked	
20040088	Gas	IO	TP		Pipeline was improperly located and marked	
20060146	Gas	IO	TP		Pipeline was improperly located and marked	
20070115	Gas	IO	TP		Pipeline was improperly located and marked	Wrong line located
20130013	Gas	IO	TP		Pipeline was improperly located and marked	
20140087	Gas	IO	TP		Pipeline was improperly located and marked	Line not mapped
20140097	Gas	IO	TP		Unsuitable clearance supervisor; wrong dig practice	No hand dig practice

Incorrect Operations and Previously Damaged Pipe (IO + PDP)

Mechanical damage that survives initially but fails at a later time is classified as previously damaged pipe. IO + PDP interaction accounted for seven incidents in HL lines (Table B-47) and one incident in a GAS line. The majority reported a dent/crack that propagated by vibration or pressure-cycle-induced fatigue.

Table B-47. IO + PDP Interactions in Hl Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19870065	HL	IO	PDP		Crack in dent propagated by fatigue	
20010008	HL	IO	PDP		Residual stresses and vibration fatigue	Patch
20040327	HL	IO	PDP		Crack propagated by fatigue	
20050161	HL	IO	PDP		Pressure cycle enlargement of transportation crack	
20090161	HL	IO	PDP		Crack in dent propagated by fatigue	
20100165	HL	IO	PDP		Crack propagated by fatigue	
20140373	HL	IO	PDP		Crack in dent propagated by fatigue	

Incorrect Operations and Vandalism (IO + V)

Vandalism is a deliberate act causing damage to or failure of a pipeline. Some areas of the pipeline, such as manned compressor stations, and some critical operations such as gas control centers, are subjected to security procedures implemented to prevent entry into areas or acts by untrained or unauthorized personnel. Where these procedures are implemented, they become important to preventing vandalism. However, no incidents were found with the IO + V interaction.

Incorrect Operations and Earth Movement (IO + EM)

Some soil movement events are sudden and can occur with little or no warning. However, some soil movement events occur gradually over time and can be identified while in progress. Visual evidence of cracks developing in the soil or trees observed to be growing at some angle to the soil other than 90 degrees can indicate the presence of gradual soil movement. Many pipeline operators have written procedures to look for and report such conditions along the right of way (ROW). IO + EM interaction accounted for only two incidents in HL lines. In one case two lines were in contact and ground vibration rubbed a hole.

Incorrect Operations and Heavy Rains or Floods (IO + HRF)

Failing to identify river bank erosion, loss of weight coating, free spans in waterways with the potential for high currents, could result in an increased risk of failure during a flooding event. This interaction accounted for five incidents in HL lines (Table B-48); four of them resulted in a sump overflow.

Table B-48. IO + HRF Interactions in HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19910205	HL	IO	HRF		Side of an excavation sloughed off during heavy rains	
20120156	HL	IO	HRF		Missing gasket on top hatch; sump overflow.	
20130227	HL	IO	HRF		Sump without high level alarm; overflow	
20140298	HL	IO	HRF		Valve w/o rain cover; water entered system; overflow	
20140314	HL	IO	HRF		Loss of power; relief of overpressure; sump overflow	

Incorrect Operations and Lightning (IO + LIGHT)

There is a possible connection between incorrect operations and lightning. One incident in an HL lines was said to have been caused by this interaction.

Incorrect Operations and Cold Weather (IO + CW)

Incorrectly operating the pipeline in cold weather can cause hydrates in the pipeline to freeze, either restricting flow or shutting off flow in the pipeline. This condition often arises downstream of pressure reductions which causes significant cooling effects. The flow restriction or blockage could lead to a pressure excursion and a resulting failure. Failure to drain accumulated water from piping systems and components can lead to failures from ice formation.

IO + CW interaction accounted for 24 incidents in HL lines (Table B-49) and two incidents in GAS lines. Fourteen incidents were caused by of ice freezing inside the line or its components.

Table B-49. IO + CW Interactions in HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19890020	HL	IO	CW		Attempt to thaw ice plug caused release	
19890068	HL	IO	CW		Hydrotest water froze and ruptured 3 joints	
19900005	HL	IO	CW		Girth weld broke from pipe contraction	No details
19900022	HL	IO	CW		Overexpansion from temp shift and internal pressure	
19900023	HL	IO	CW		Overexpansion from temp shift and internal pressure	Double entry?
19920046	HL	IO	CW		Ice freezing in water drain	
19920048	HL	IO	CW		Ice trapped in the tapped holes prevented tightening	
19940029	HL	IO	CW		Ice freezing in water drain	
19940147	HL	IO	CW		Heaving due to frost coming out of the ground	
20000015	HL	IO	CW		Water in line froze at valve and dead leg	
20000026	HL	IO	CW		Pipe overstressed due to ice in water	
20000035	HL	IO	CW	TSBPC	Ice formed in or around bolted flange	
20010015	HL	IO	CW		Water freeze in a seal pot device	
20030069	HL	IO	CW	MCRE	Stinger froze. Ice jarred vent valve.	
20030086	HL	IO	CW		Line froze while idle. Pump overpressurized manifold.	
20030098	HL	IO	CW		Deadleg froze and broke. Plug resisted pressure test.	
20030109	HL	IO	CW		Ice trapped in L-pipe arrangement froze	
20050018	HL	IO	EM	CW	Vibration, lack of support and soil thawing	
20100057	HL	IO	CW		Valve seal failure and ice jam in line.	
20100244	HL	IO	CW		Frostheave fatigue/ No expansion joints.	
20120060	HL	IO	CW		Thermal relief tubing froze and broke	
20140031	HL	IO	CW		Roof drain froze and broke seal	
20140176	HL	IO	CW		Water ingress in gauge (snow melting)	
20150037	HL	IO	CW		Niple cracke because of ice expansion	Replaced/redesigned

Third Party Damage and Heavy Rains or Floods (TP + HRF)

Third-party damage includes incidents resulting immediately from encroachment by outside parties and by pipeline operators and their contractors. But it also includes impacts by debris and objects hurled by high winds or currents. TP + HRF interaction accounted for 13 incidents in HL lines (Table B-50) and 17 incidents in GAS pipelines (Table B-51). The majority of incidents affecting HL lines are caused by debris blown by the wind or carried by flood waters. However, in three cases the cause was remediation excavation without notification to the operator. The incidents in GAS pipelines are all offshore and happened during a hurricane; they all happened after 2004.

Table B-50. TP + HRF Interactions in HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19860195	HL	TP	HRF		Landowner start plowing before operator arrived on site	
19870220	HL	TP	HRF		Maintainer trying to reroute water running down	
19930114	HL	TP	HRF		Tree or object struck line	
19930180	HL	TP	HRF		Line hit by debris carried by flood waters	
19950117	HL	TP	HRF		Line hit by debris carried by flood waters	
19990057	HL	TP	HRF		Farmer carried remediation without calling	
19990064	HL	TP	HRF		Pole was blown over hitting pump and valve	
20010058	HL	TP	HRF	TSBPC	Board was blown shearing off pipe nipple	
20010060	HL	TP	HRF	TSBPC	Lid blown striking pipe nipple	
20050361	HL	TP	HRF		Anchor dragged during hurricane tidal surge	
20070201	HL	TP	HRF		Line hit by debris carried by river	
20090160	HL	TP	HRF	TSBPC	Pole was blown over hitting nipple	
20150289	HL	TP	HRF		Line hit by debris blown by wind	

Table B-51. TP + HRF Interactions in GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
20040091	Gas	TP	HRF		Anchor dragged by hurricane	
20050101	Gas	TP	HRF		Boat damage during hurricane	
20060020	Gas	TP	HRF		Anchor dragged by hurricane	
20060051	Gas	TP	HRF		Anchor dragged by hurricane	
20080107	Gas	TP	HRF		Jack-up rig drifted into pipeline	
20080108	Gas	TP	HRF		Jack-up rig drifted into pipeline	
20080111	Gas	TP	HRF		Platform toppled over onto pipeline	
20080113	Gas	TP	HRF		Platform toppled over onto pipeline	
20080115	Gas	TP	HRF		Platform toppled over onto pipeline	
20080116	Gas	TP	HRF		Platform toppled over onto pipeline	
20080117	Gas	TP	HRF		Platform toppled over onto pipeline	
20080118	Gas	TP	HRF		Platform toppled over onto pipeline	
20080122	Gas	TP	HRF		Platform toppled over onto pipeline	
20080124	Gas	TP	HRF		Platform toppled over onto pipeline	
20080148	Gas	TP	HRF		Anchor dragged by hurricane	
20090036	Gas	TP	HRF		Platform toppled over onto pipeline	
20060037	Gas	TP	HRF		Anchor dragged by hurricane	

There is no other interaction between TP and other threats with significant incident count, except for those already mentioned.

Previously Damaged Pipe (PDP)

There is no other interaction between PDP and other threats with significant incident count except for those already mentioned.

Vandalism (V)

There is no other interaction between V and other threats with significant incident count except for those already mentioned.

Earth Movement and Heavy Rains and Floods (EM + HRF)

Heavy rains can sometimes cause soil to become saturated and thereby contribute to its movement. Many landslides result from soil layers which, when water-saturated, become unstable.

EM + HRF interaction accounted for 15 incidents in HL lines (Table B-52) and 14 incidents in GAS lines (Table B-53). Eight incidents in HL lines and 11 incidents in GAS pipelines were caused by landslides or mudslides in sloped terrain or near open faces. Four incidents in HL lines were caused by underwater mudslides.

Table B-52. EM + HRF Interactions for HL Transmission Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19870125	HL	EM	HRF		Slope lateral spread	
19870132	HL	EM	HRF		Soil erosion; Line unsupported.	
19870155	HL	EM	HRF		River crossing washed out	
19890006	HL	EM	HRF	IO	Trench cave-in. Pipe lifted and bent.	
19920163	HL	EM	HRF		Mudslide	
19940005	HL	EM	HRF	MISC	Subsidence caused by flooding and heavy traffic	
19980027	HL	EM	HRF		Slope lateral spread	
19980028	HL	EM	HRF		Slope lateral spread	
20040317	HL	EM	HRF		Underwater mudslide	
20050278	HL	EM	HRF		Levee supporting line was washed out	
20050322	HL	EM	HRF		Underwater mudslide	
20060098	HL	EM	HRF		Lateral spread; pipeline rubbed another line.	
20060346	HL	EM	HRF		Underwater mudslide	
20120010	HL	EM	HRF		Underwater mudslide	
20130336	HL	EM	HRF		Mudslide, rock impacts	

Table B-53. EM + HRF Interactions for GAS Transmission and Gathering Lines

Report Number	System	Threat 1	Threat 2	Threat 3	Cause	Comments
19950071	Gas	EM	HRF		Landslide failed several girth welds	
20050030	Gas	EM	HRF		Landslide in area not known to be susceptible	
20050036	Gas	EM	HRF		Landslide in area not known to be susceptible	
19930051	Gas	EM	HRF		Landslide	
19930055	Gas	EM	HRF		Landslide - failure at girth weld	
19970028	Gas	EM	HRF		Mudslide	
20050053	Gas	EM	HRF		Landslide which caused buckle which cracked	
20050123	Gas	EM	HRF		Mudslide	
20050154	Gas	EM	HRF		Mudslides with severed lines	
20130074	Gas	EM	HRF		Washout and drag out of line	
20050059	Gas	EM	HRF		Soil movement during flash flooding	
19960094	Gas	EM	HRF		Landslide which caused wrinkle bend that failed	
20110370	Gas	EM	HRF		Terrain instability; line failed at girth weld	

Heavy Rains or Floods (HRF)

There is no other interaction between HRF and other threats with significant incident count except for those already mentioned.

Lighting (LIGHT)

There is no other interaction between LIGHT and other threats with significant incident count except for those already mentioned.

Cold Weather (CW)

There is no other interaction between CW and other threats with significant incident count except for those already mentioned.

APPENDIX C – PIPELINE STRAIN ANALYSIS IN BIAXIAL LOADING

The longitudinal stress dominates the integrity of a pipeline during landslide. It can be determined through total longitudinal strain, $\epsilon_{\mathrm{Total}}$, with three components as follows:

$$\epsilon_{\mathrm{Total}} = \epsilon_{\mathrm{B}} + \epsilon_{\mathrm{U}} + \epsilon_{\mathrm{O}} \tag{1}$$

where

ϵ_B is the bending strain due to curvature changes in the moved segment,

ϵ_{U} is the uniform elongation strain as the length changes in the displaced segment, and

ϵ_{O} is the operational strain from internal pressure and thermal deformation.

Bending Strain

The bending strain can be determined by the changes of curvature along the pipeline as follows:

$$\epsilon_{\mathrm{B}} = \frac{D}{2}(\kappa - \kappa_0) \tag{2}$$

where

D is outside diameter of the pipe,

κ_0 and κ are the curvatures of the pipe axis before and after the landslide, respectively.

Equation (2) assumes that there is no longitudinal strain from the initial curvature before landslide.

Uniform Elongation Strain

The overall length of the pipeline segment increases during the ground displacement to accommodate the new profile. Such changes of length result in an elongation strain distributed almost uniformly along the moved segment as the soil has relatively low restriction along pipeline axial direction. The uniform elongation strain can be then determined as follows:

$$\epsilon_{\mathrm{U}} = \frac{L - L_0}{L_0} \tag{3}$$

where L_0 and L are the lengths of the joint before and after landslide, respectively.

Operational Strain

Operational longitudinal strain is the equivalent strain resulting from normal operation condition in a constrained pipeline along axial direction[15] as

$$\epsilon_{\mathrm{O}} = \nu \frac{pD}{2Et} - \alpha \Delta T \tag{4}$$

where

p is internal pressure,

t is pipe wall thickness,

ν and E are Poisson's ratio and elastic modulus of steel,

α is the thermal expansion coefficient of steel,

and ΔT is the temperature difference between current operating condition and installation conditions.

There are two scenarios that need consideration. During the landslide or soil subsidence, the pipeline should be considered operating at normal pressure and temperature conditions. During pipeline shutdown, the internal pressure should be considered zero. In addition, after the ground displacement, the pipeline might be exposed in open air and the temperature of the pipe would equal the ambient temperature in the air.

Pipeline Profile

The profile of the displaced pipeline can be characterized by field survey or by a geometrical ILI tools. Geometry ILI tools are capable of measuring the pipeline centerline orientation (pitch and azimuth) and odometer distance from which the northing, easting and elevation coordinates and the vertical, horizontal. Geometry ILI tool vendors will typically provide a detailed survey report which includes an overall summary of the pipeline geometry and in some cases a listing of locations where the client-specified curvature or bending strain thresholds are exceeded. Typical software plots include plan views of the pipeline, along-the-pipe profiles of pipe centerline elevation, pitch and azimuth as well as vertical, horizontal and total curvature or

[15] The equivalent strain here refers to the strain in a tensile bar under the same stress level. It is distinguished from real strain measured from the pipe. For example, in a pipe that is fully constrained along the axial direction, the decrease of temperature results in tensile stress from restrained thermal contraction. The equivalent strain would be the tensile strain in a tensile bar under the same level the tensile stress. However, the measured longitudinal strain should be zero as the pipe is fully constrained in the axial direction.

bending strain. Vendor software packages should allow for curvature/bending strain calculations based on a user-specified gage length and should include the capability to filter these profiles for example using low-pass filtering to remove high frequency (short wavelength) noise features. It is also possible to develop plots showing all girth weld locations as well as other pipeline features that are programmed into a client-supplied pipeline as-built data base or pipe joint length tally. Overlaying plots of these quantities from multiple surveys is also possible to facilitate survey-to-survey comparisons of various geometry measures.

Current geometry pig measurements of the pitch and azimuth for estimating the curvature can contain a significant level of noise [27]. Frequently, the gage length used in computing the curvature is adjusted so as to act as a filter; a larger gage length provides greater filtering or smoothing of the curvature signal.

Finite Element Analysis

The analysis of strain in a buried pipeline subjected to lateral spread displacements generally requires finite element analysis that accounts for nonlinear behavior of the pipeline and surrounding soil and large displacement effects. Inelastic pipe behavior is simulated by specifying a nonlinear stress-strain curve for the pipeline steel. Typical elements used in determining pipeline response account for nonlinear stress-strain behavior, but not compressive buckling or wrinkling of the pipe wall. Consequently, it is necessary to apply test-based compressive strain criteria that normalize axial strains over a particular length of pipeline encompassing the wrinkled or buckled sections (usually about one to two pipe diameters). The segment of the pipeline used in the analysis model should extend away from the zone of ground displacement to points of virtual soil anchorage.

The pipeline strain criteria presented in the above section have been validated with FEA analysis by Hart *et al.* [27] and Kiefner.

APPENDIX D - CYCLIC LOADING CRITERIA

Failure Due to Cyclic Loading

Pipelines can be subjected to cyclic loadings that result in changes in the longitudinal and hoop stress levels, such as variations of pipe body temperature and internal pressure. A pipeline that is exposed to a high number of stress cycles can experience failure due to progressive damage accumulation. A fatigue crack can initiate from an existing imperfection in a weld or pipe body and propagate until the remaining cross-section becomes incapable of sustaining the applied stresses. In a pipeline a fatigue crack usually starts from an existing surface or embedded imperfection growing into the base metal, starts from a joint weld imperfection growing into the base metal or from a joint weld imperfection growing through the weld [52].

A fatigue assessment estimates the time for a crack to initiate in a crack-free structure. Fatigue assessment requires knowledge of two basics, namely a fatigue curve and a damage accumulation rule. A fatigue curve, known as S-N (applied stress versus number of cycles) curve, specifies number of cycles to failure for a given stress range. During its lifetime a pipeline can experience stress cycles of various magnitudes. For example, while shutting down a line can reduce the hoop stress from its maximum value to zero (full range), a reduction in the internal pressure from MOP to 0.9 MOP produces a stress change that is only 10% of a full cycle. Similarly, the ambient temperature variations from a low winter temperature to a high summer temperature imposes a full thermal stress cycle on an exposed pipe, while daily temperature variations produce 365 cycles of lesser magnitudes. Therefore, a model is needed to convert a partial stress range to an equivalent number of full range cycles. This is achieved by the use of a damage accumulation rule such as Miner's Rule. The primary factor that dictates the fatigue life for a given material is the magnitude of the stress range. The mean stress (average of the high and the low stresses in a cycle) can also affect the fatigue life of the material. However, this effect is usually of second order and is not usually taken into account during a basic fatigue analysis.

Rainflow cycle count methodology can be used to characterize load cycles based on an available load spectrum. The analysis can be conducted in accordance with ASTM E1049 [53]. Rainflow cycle count of stress cycles based on an existing stress spectrum is usually demanding and requires automation. All external loads that could potentially affect the life of the pipeline should be considered (i.e. traffic surface loads, thermal cycling, etc.). Once the load ranges and the number of cycles associated with each range are determined the next step is to calculate the primary stresses associated with each range. This is achieved either by conducting a numerical stress analysis (e.g. finite element analysis) or by using the closed-form equations such as provided in this report.

For example, if fatigue life of a dent under a given pressure spectrum is of concern, the dent SCF (dent stress concentration factor) can be calculated according to the methodology

described in the PRCI Report L51810, “Guidelines for the assessment of dents on welds” by M. Rosenfeld [54]. This method was originally developed for fatigue analysis of dented girth welds but can also be used for the base metal. Dent SCF generally increases with pipe D/t and dent depth, while it decreases with increasing mean pressure level (as a result of re-rounding effect of internal pressure). Dent SCF is calculated for a unique combination of D/t, d/D and P_m as below:

$$k_d = 1 + \left(\frac{d_i}{t} m_y + b_y \right) \left(\frac{2t}{D} \right) \tag{5}$$

$$b_y = \begin{cases} -5 & \text{if } \dfrac{D}{t} \le 30 \\ b_a + \dfrac{b_b}{\left(\dfrac{D}{t}\right)} + \dfrac{b_c}{\left(\dfrac{D}{t}\right)^2} + \dfrac{b_d}{\left(\dfrac{D}{t}\right)^3} & \text{if } \dfrac{D}{t} > 30 \end{cases} \tag{6}$$

$$b_a = 2.215 + 0.0166 P_m - 0.00002946 P_m^{\ 2} \tag{7}$$

$$b_b = -526.3 - 3.299 P_m + 0.004133 P_m^{\ 2} \tag{8}$$

$$b_c = 180400 + 70.11 P_m - 0.1527 P_m^{\ 2} \tag{9}$$

$$b_d = -5069500 + 290.5 P_m + 1.708 P_m^{\ 2} \tag{10}$$

$$m_y = \begin{cases} \mathrm{a}_p + \dfrac{b_p}{\left(\dfrac{D}{t}\right)} + \dfrac{c_p}{\left(\dfrac{D}{t}\right)^2} & \text{if } \dfrac{D}{t} \le 50 \\ a_p + b_p \left(\dfrac{D}{t} \right) & \text{if } \dfrac{D}{t} > 50 \end{cases} \tag{11}$$

where

d_i is dent depth under zero internal pressure, inch,

D is pipe OD, inches,

t is pipe wall thickness, inch, and

P_m is the mean pressure, psig. P_m is calculated as the average of the maximum and the minimum internal pressures.

The values of a_p, b_p, and c_p are calculated according to Table D-1.

Table D-1. Values of a_p, b_p and c_p for Dent Stress Intensity Factor Calculations

	D/t≤ 50		**D/t > 50**	
	P≤900	**P>900**	**P≤900**	**P>900**
a_p	$-6.87P_m + 4490$	$P_m - 2580$	$-3P_m + 3475$	$-0.0775P_m + 848$
b_p	$309P_m - 118100$	$-80P_m + 231500$	$0.02P_m - 20.7$	$-0.00065P_m - 2.03$
c_p	$-3472P_m + 930700$	$1154P_m - 3233000$	N. A.	N. A.

Equation (5) can be applied to the Barlow's equation to determine a set of hoop stress ranges for each pressure range:

$$\Delta\sigma_H = k_d \frac{\Delta P \cdot D}{2t} \tag{12}$$

S-N curves used for fatigue analysis provide the expected number of cycles to failure (N) as a function of stress range ($\Delta\sigma$). S-N curves have been developed from cyclic tests to failure for various materials. Figure D-1 shows an example of such a curve for smooth bar specimen from API 579 and also ASME Boiler & Pressure Vessel Code, Div. 2.

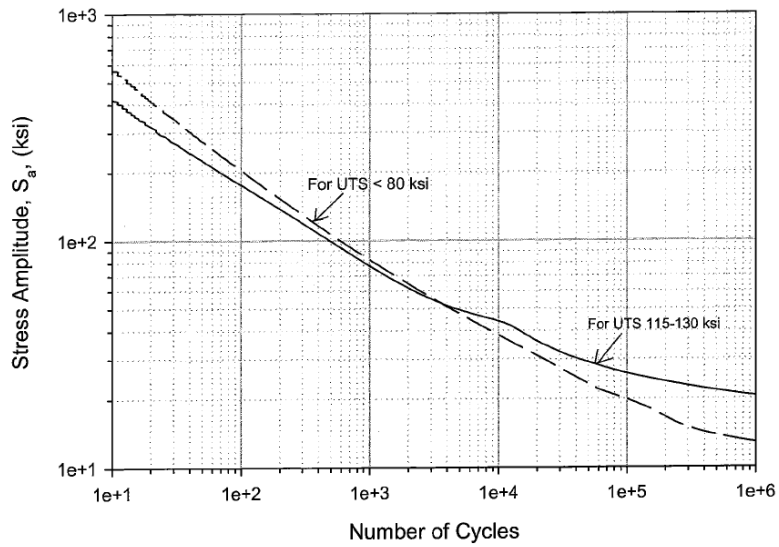


Figure D-1. API 579 Smooth Bar Specimen Fatigue Curve [55]

API 579 methodology for fatigue analysis utilizes the master S-N curve approach which is relatively complex for manual calculations. However, the first edition of API 579 [56] provides a simpler equation based on welded test specimens that is more suitable for manual calculations:

$$N = A\left(\Delta\sigma \cdot C_{\mathrm{su}}\right)^{-m} \tag{13}$$

where

A is fatigue data constant dependent on the weld class (see Table D-2 below),

Csu is a unit conversion constant: Csu = 1.0 if stress range is in MPa while Csu = 1.0/6.894757 if the stress range is in ksi,

$\Delta\sigma$ is stress range,

m is negative inverse slope of S-N curve, and

N is the expected number of cycles to failure.

Table D-2. Fatigue Curve Coefficients Based on Welded Test Specimen [56]

Weld Class	For N≤5.0E6 cycles		For N>5.0E6 cycles	
	m	A	m	A
124+	3.5	4.25E13	5.5	3.87E17
100	3.0	2.00E12	5.0	1.10E16
80	3.0	1.02E12	5.0	3.57E15
63	3.0	5.00E11	5.0	1.03E15
50	3.0	2.50E11	5.0	3.47E14
40	3.0	1.28E11	5.0	1.03E14

Note: If the applied stress range, σ_r, exceeds 111,099 psi (766 MPa) or N is less than 3380 cycles use class 100

For fatigue analysis of high strength base metal with yield strength higher than 500 MPa (72.5 ksi) DNV-PR-C203 [52] recommends the following equation:

$$N = 2.7925 \times 10^{17} \left(\Delta\sigma \cdot C_{\mathrm{su}} \right)^{-4.7} \tag{14}$$

More S-N curves can be found in DNV-PR-C203 [52], API 579 [55], and ASME BPV Code, Section VIII, Division 2, Appendix 5 [57]. Care should be taken to select the appropriate fatigue curve, as the pipeline codes contain different curves for smooth pipe, welded-joints, etc.

When a pipe is exposed to K stress ranges of $\Delta\sigma_i$ magnitude the accumulative damage can be calculated using Miner's Rule:

$$\mathrm{D} = \sum_{i=1}^{K} \frac{n_i}{N_i} \tag{15}$$

where

n_i is the number of cycles associated with $\Delta\sigma_i$, and

N_i is the corresponding number of cycles to failure from Equation (13), Equation (14), or a selected S-N curve.

Failure occurs when D reaches unity (D=1). A minimum factor of safety of 2 is recommended when using Equation (15) to estimate the remaining time to failure. That is, the remaining time to failure should be divided by two. Equation(16) can be used as an alternative to Equation (15), to convert one partial range cycle to an equivalent full cycle:

$$n_{i_eq} = \left(\frac{\Delta\sigma}{\delta \cdot \sigma_i} \right)^m \tag{16}$$

where

$\Delta\sigma$ is the full stress range,

$\delta\sigma_i$ is i^{th} the stress range that acts on the material, and

n_{i_eq} is the equivalent number of full stress range cycles.

Crack Growth under Cyclic Loading - Paris Law

The Paris Law determines the fatigue crack growth rate of a crack under cyclic loading. The Paris Law equation is given by API 579 [55] as:

$$\frac{da}{dN} = C(\Delta K)^n \tag{17}$$

where

da/dN is increment of crack growth for a cycle,

C is crack growth rate constant,

n is crack growth rate exponent, and

ΔK is change in stress intensity factor as a result of the stress range.

Section F.5.3.2 of API R579 recommends the following values for ferritic and austentic steels in air or other non-aggressive environments:

n = 3.0

C = 8.61E-10 for in/cycle and ksi√in

C = 1.65E-8 for mm/cycle and MPa√m

Blunt Metal Loss and Dent under Cyclic Loading

The main concern with a blunt metal loss and indented pipe or girth weld is fatigue failure under cyclic load leading to pipe leakage. The approach is to determine an appropriate stress-concentration factor to intensify the nominal stresses that acts on a pipe. The assessment consists of the following steps:

1- Conduct a Rain-flow cycle count to characterize pressure load cycles based on a representative pressure spectrum. This analysis can be conducted in accordance with ASTM E1049. Determine the stress ranges associated with each load cycle.

2- Determine the appropriate SCF as described previously. Apply the stress concentration factor to the stress ranges from Step 1, calculating intensified stress cycles. For a dent under internal pressure, SCF is dependent on the average internal pressure, and therefore, a new SCF should be calculated for each mean pressure.

3- Select an appropriate S-N curve representative of pipe or weld material at the location of the imperfection.

4- Estimate the fatigue life using Miner's Rule Equation (15) or Equation (16).

Crack-Like imperfection under Cyclic Loading

A planar flaw under cyclic loading can continue to grow until the remaining cross-section of the pipe becomes incapable of sustaining the applied loads. The assessment approach is to utilize Equation (17) to estimate the size of a crack as a function of time. The (L_r^P, K_r) pair is calculated at each time step (refer to Appendix U for Failure Assessment Diagram). If the (L_r^P, K_r) pair lies under the FAD curve the imperfection is acceptable and the calculations can continue to the next time step. The assessment consists of the following steps (Figure D-2):

1- Select representative material parameters for use in Equation(16), Equation (17) and for crack assessment using FAD approach.

2- Conduct a cycle count on a representative pressure spectrum. The cycle counting can be conducted in accordance with ASTM E1049 (known as 'rainflow'). The outcome of the cycle count is a set of pressure ranges ($\delta\sigma_i$) with a number of cycles for each pressure range (n_i).

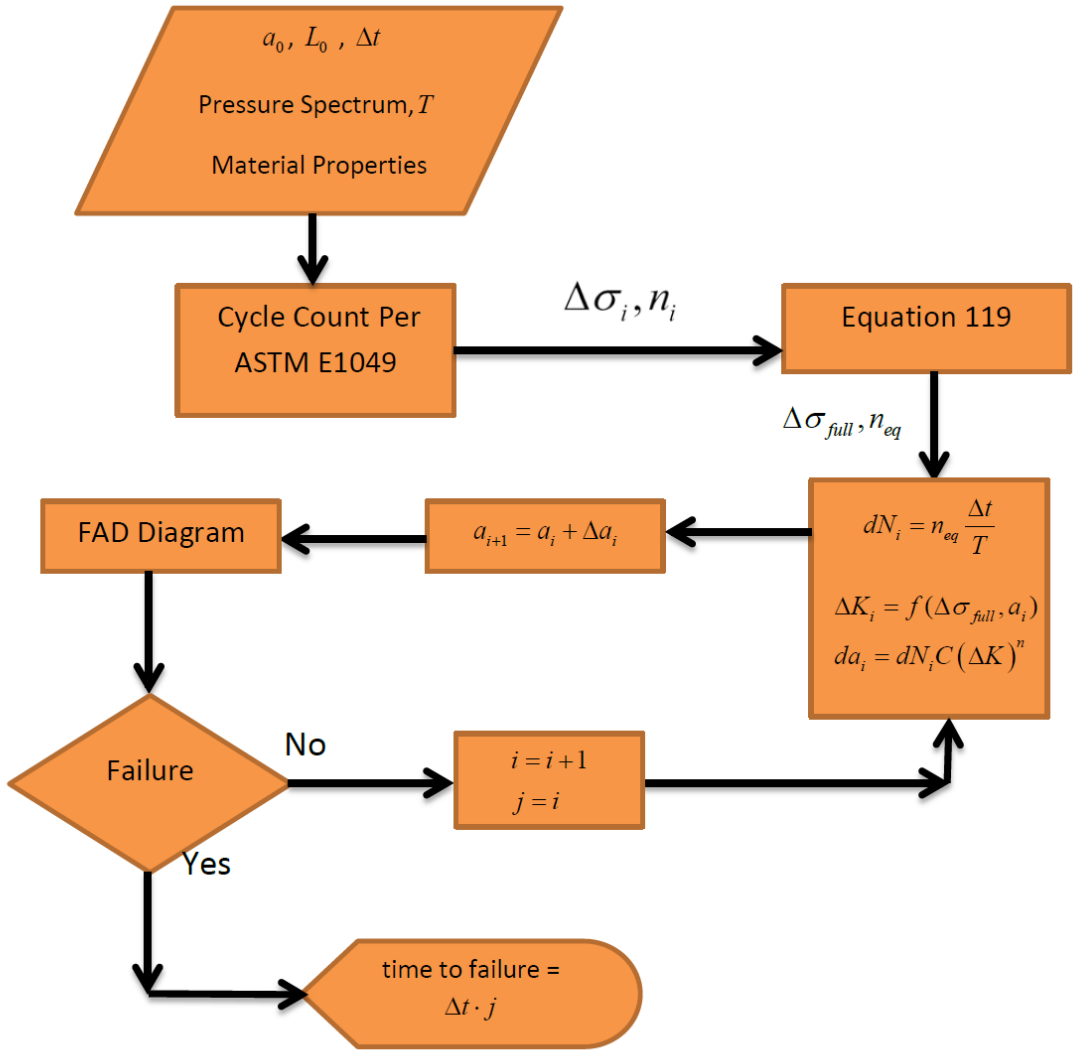
3- Convert the partial load cycles of Step 2 to full range cycles using Equation (16). The outcome of this step is the equivalent number of full range cycles for a given operation duration (such as N cycles of full stress range per year).

4- Select an appropriate time increment for each step of the analysis. The smaller the time increment the more accurate the analysis. The time increment should be small enough that the crack growth at each step remains a small percentage of the wall thickness (e.g. 0.1%). Calculate the number of cycles that the pipe will experience for the selected time increment using the output of Step 3.

5- Starting with the initial crack size, calculate crack stress intensity factor and the reference stress for the full loading range.

6- Use the FAD approach to determine if the current crack size is acceptable. If the FAD does not indicate failure, proceed to the next step. If FAD predicts failure, stop the calculations and record the time to failure.

7- Determine the amount of crack growth for the selected time increment using Equation (17). Calculate the new crack size and go to Step 5.



a_0 and L_0 are initial crack dimensions

Δt is the selected time interment

ΔK is change in stress intensity factor as a result of stress range

$\Delta\sigma_{full}$ is full stress range

T is total duration of the pressure spectrum

Figure D-2. Assessment of Crack-Like Imperfection under Cyclic Loading

Steps 5 through 7 are repeated until failure is detected, or the crack grows beyond acceptable limits (*e. g.* 50% wall thickness). It is a good practice to repeat the calculations using a different (and smaller) time step to assure that the solution is independent of the selected time step. Performing such calculations manually is tedious and might be impractical. Commercially-available software programs can be obtained to do the analyses quickly.

Rate Dependent Loading

In some cases, the imperfection growth can be time dependent instead of cycle dependent. Examples are corrosion (which depends on environment), hydrogen assisted cracking (HAC) and stress corrosion cracking (SCC) (that depends on environment, stress and material susceptibility). In these cases, it is necessary to determine a rate in order to perform an evaluation. For purely environmental growth such of corrosion the analysis consists of calculating the increase in depth, length and width of the imperfection and then calculating the failure load using the appropriate failure criterion. In the case HAC and SCC a crack growth law similar to the Paris law (Equation (17)) may be required with da/dN replaced by da/dt where t is time. The difficulty with these types of analyses is establishing the rate constants. Corrosion rates can be established directly through successive MFL runs or the use of corrosion coupons. Guidance for HAC rates can be found in API 579 Appendix F. CEPA has published several reports on SCC that contain information on crack growth rates.

Combined Cyclic/Rate Dependent Loading

If more than one type of loading is present we recommend breaking the loading into smaller interval blocks and determining the number of blocks until failure is predicted. For instance, if there is a crack-like feature in a corrosion imperfection then you might determine the number of stress cycles in a month. The sequence would be to increase the corrosion depth using the corrosion rate and then apply the cyclic loading to the crack-like feature. The new corrosion depth and crack depth is then the starting point for the next block. This type of an analysis is probably best done using a computer program or some type of programmable software. We would also recommend performing the analysis ordering the components in each block in different orders as the sequence can affect the final outcome in some cases.

APPENDIX E - MONOTONIC INCREASING LOADS CRITERIA

Surface Loading

When a buried pipeline is exposed to a surface load such as a traversing vehicle, the load is imparted into the pipeline through the soil. Surface loading analysis is used to determine this load. The load experienced at pipeline depth is primarily a function of the depth of soil cover and the size of the ground contact area. The surface load causes cross-sectional ovalization and longitudinal bending deflections, while imposing longitudinal and hoop stresses on the pipeline. Pipe stiffness, internal pressure, and lateral soil stiffness contribute to the overall pipe resistance against the ovalization.

The Spangler and Iowa [58] equations have been widely used for surface load analysis and have been recommended by several industry guidelines including API Recommended Practice 1102 Steel Pipelines Crossing Railroads and Highways [59] and American Lifelines Alliance Guidelines for the Design of Buried Steel Pipe [26]. In 2005 Canadian Energy Pipeline Association (CEPA) [60] developed a surface load analysis method that combines the internal pressure and lateral soil resistance into a single equation for circumferential bending stress. In the absence of internal pressure, the CEPA equation reduces to the Iowa equation. It shrinks to the Spangler equation if lateral soil restraint is negligible. The CEPA equation, presented herein, is the method recommended and used by Kiefner for surface load analysis of pipelines.

Soil Overburden Pressure

The prism load of the column of soil over the pipeline is used to determine the overburden pressure on the pipe:

$$P_{\text{soil}} = \frac{\rho_{\text{soil}} \cdot H}{144} \tag{18}$$

where

P_{soil} is the pressure on the pipe due to soil overburden, psi,

ρ_{soil} is the density of the soil, lbs/ft^3, and

H is the height of soil over the top of the pipe, ft.

Other equations for overburden pressure assessment such as Marsdon's load theory, also known as trench formulas, are not appropriate for a flexible pipe. Moser recommends the prism load for flexible pipe in his Buried Pipe Design book [61].

Surface Loading Pressure at Pipe Surface

The Boussinesq equation [62] is used to calculate the pressure at the surface of the pipe resulting from a surface load. The pressure at the pipe surface is given by:

$$P_{\text{live}} = \frac{3P_{\text{surface}}}{2\pi\left(12H\right)^2\left(1+\left(\frac{z}{H}\right)^2\right)^{\frac{5}{2}}} \tag{19}$$

where

P_{live} is pressure at the pipe surface, psi,

$P_{surface}$ is concentrated load at the surface, lbs,

H is depth of soil over pipe, ft and

z is horizontal offset of the measurement point with respect to the applied load, ft.

The Boussinesq equation is based on elasticity assumption, and therefore, it can be generalized to any type of surface loading through numerical integration of the applied load over the load contact area (superposition principle). For example, if the load is a uniform pressure over an area with any arbitrary shape, the area can be divided into a grid of small rectangles with a concentrated load on each rectangle that equals the pressure times the area of the rectangle. The total pressure at any point underground can be obtained by summing the contribution from each rectangle to the pressure at the point.

Failure Due to Surface Loading

Kiefner recommends the CEPA formula because it accounts for the stiffening of the pipe resulting from pressure and lateral soil support. Neglecting the soil lateral support leads to overestimated hoop stress. The equation is based on the commonly used Spangler stress formula for a pressurized pipe and the Iowa formula for an unpressurized pipe. The CEPA equation is:

$$\sigma_{\text{H_CEPA}}\left(W\right) = \frac{3k_b \cdot W \cdot \left(\frac{D}{t}\right)^2}{1+3k_z\left(\frac{P}{E}\right)\left(\frac{D}{t}\right)^3 + 0.0915\left(\frac{E'}{E}\right)\left(\frac{D}{t}\right)^3} \tag{20}$$

where

$\sigma_{H_CEPA}(W)$ is the stress in the pipe resulting from W (pressure loading at the pipe surface), psi,

k_b is bending moment parameter,

W is pressure load on the pipe (i.e. P_{soil} or P_{live}), psi,

D is pipe diameter, in,

t is pipe wall thickness, in,

k_z is deflection parameter,

P is internal pressure in pipe, psig,

E is modulus of elasticity of the steel (30x106 psi), and

E' is modulus of soil reaction, psi.

Table E-1 and

Table E-2 provide typical values for k_b, k_z and E'. The bedding angle in Table E-1 is an estimate of the amount of support provided by the soil. The pressure W in Equation (20) is the pressure that acts on the surface of the pipe. It should not be confused with the contact pressure that acts on the ground surface.

Table E-1. K_b and K_z based on the bedding angle [60]

Bedding Angle (deg)	Moment Parameter, k_b	Deflection Parameter, k_z
0	0.294	0.110
30	0.235	0.108
60	0.189	0.103
90	0.157	0.096
120	0.138	0.089
150	0.128	0.085
180	0.125	0.083

Table E-2. Modulus of soil reaction (E') [63]

Type of Soil	Depth of Cover (ft.)	Standard AASHTO* Relative Compaction			
		85%	90%	95%	100%
Fine-grained soils with less than 25 percent sand content (CL, ML, CL-ML)	0-5	500	700	1,000	1,500
	5-10	600	1,000	1,400	2,000
	10-15	700	1,200	1,600	2,300
	15-20	800	1,300	1,800	2,600
Coarse-grained soils with fines (SM, SC)	0-5	600	1,000	1,200	1,900
	5-10	900	1,400	1,800	2,700
	10-15	1,000	1,500	2,100	3,200
	15-20	1,100	1,600	2,400	3,700
Coarse-grained soils with little or no fines (SP, SW, GP, GW)	0-5	700	1,000	1,600	2,500
	5-10	1,000	1,500	2,200	3,300
	10-15	1,050	1,600	2,400	3,600
	15-20	1,100	1,700	2,500	3,800

- American Association of State Highway Transportation Officials

Pipe Longitudinal Stress Due to Surface Pressure

The external load on a pipe causes a local longitudinal stress. When the load is distributed over a finite length on the pipe surface, it results in a through wall bending stress that can be analyzed similarly to integral structural attachments to straight pipe as described by Dodge, W.G. [64]. The surface load can also cause a longitudinal global bending deflection in the pipe that extends beyond the limits of the loaded area. The longitudinal stress as a result of overall pipe deflection is calculated using beam on elastic foundation method.

The longitudinal stress in the pipe resulting from the surface loading is given by:

$$\sigma_{\mathrm{L_soil}} = \nu \cdot \sigma_{\mathrm{H_CEPA}}\left(P_{\mathrm{soil}}\right) \tag{21}$$

where

$\sigma_{\mathrm{L_soil}}$ is the longitudinal stress resulting from soil pressure on the pipe, psi,

ν is Poisson's ratio for steel (0.3), and

$\sigma_{\mathrm{H_CEPA}}$ is the stress calculated from Equation (20) with $W=P_{\mathrm{soil}}$, psi.

The longitudinal bending stress in the pipe resulting from the surface loading has a local and a global component. The local bending of the pipe wall results from the distributed load on the

pipe surface. The global bending is the bending of the entire pipe cross section in the longitudinal direction as a result of the distributed load. The stress resulting from the local bending is [65]:

$$\sigma_{\text{Llb_live}} = \frac{0.153}{1.56}\sqrt{12\left(1-\nu^2\right)} \cdot P_{\text{H_CEPA}}\left(P_{\text{live}}\right) \tag{22}$$

where

$\sigma_{\text{Llb_live}}$ is the local longitudinal bending stress resulting from the live surface load, psi.

The stress component resulting from the global bending is calculated based on beam on elastic foundation theory [66]. The calculation involves the flowing steps:

1- Calculate an equivalent point load based on the pressure on the pipe as defined below:

$$P_{\text{surface_equivalent}} = \frac{2\pi P_{\text{live}}\left(12H\right)^2}{3}, \text{ lbs} \tag{23}$$

In this equation the equivalent load is a virtual point load above the pipe ($z = 0$) that would result in a pressure on the pipe equal to P_{live} using Equation (19).

2- Assume that the load spreads from the surface at an angle (29.9 degrees for this example) and calculate the equivalent length of the pipe over which the $P_{\text{surface_equivalent}}$ from Equation (23) acts[16]:

$$L_{\text{equivalent}} = 12H \cdot \tan\left(29.9^\circ\right), \text{ in} \tag{24}$$

3- Calculate an equivalent distributed load on the pipe based on the equivalent load from Equation (23) and equivalent length from Equation (24):

$$W_{\text{distributed}} = \frac{P_{\text{surface_equivalent}}}{\pi L_{\text{equivalent}}^2} D, \text{ lbs/in} \tag{25}$$

4- Calculate the maximum bending moment on the pipe from the $W_{\text{distributed}}$ acting over the equivalent length, $L_{\text{equivalent}}$, using beam on elastic foundation theory:

[16] The actual length is greater but a shorter equivalent length will result in a higher bending moment, and therefore, is a conservative approximation. Also, the actual load distribution is not uniform.

$$I = \frac{\pi}{4}\left(\left(\frac{D}{2}\right)^4 - \left(\frac{D}{2} - t\right)^4\right), \ \text{in}^4 \tag{26}$$

$$\lambda = \sqrt[4]{\frac{k}{4E \cdot I}} \tag{27}$$

$$B_\lambda\left(x\right) = e^{(-\lambda x)} \sin\left(\lambda x\right) \tag{28}$$

$$M_1\left(x\right) = \frac{W_{\text{distributed}}}{4\lambda^2}\left(B_\lambda\left(x + L_{\text{equivalent}}\right) + B_\lambda\left(x - L_{\text{equivalent}}\right)\right), \ \text{in} \cdot \text{lb} \tag{29}$$

$$M_2\left(x\right) = \frac{-W_{\text{distributed}}}{4\lambda^2}\left(B_\lambda\left(x - L_{\text{equivalent}}\right) - B_\lambda\left(x + L_{\text{equivalent}}\right)\right), \ \text{in} \cdot \text{lb} \tag{30}$$

In the above equation x is distance along the pipe, measured from the center of the loaded area, while B_λ in Equation (28) is a function of x. The spring constant that is used in Equation (27) is $k = \bar{E} \cdot D \cdot \frac{\varphi}{360}$, in which φ is the bedding angle from Table E-1,

5- Determine the maximum and minimum value of $\text{M}_1\left(x\right)$ and $\text{M}_2\left(x\right)$ by calculating or plotting

$\text{M}_1\left(x\right)$ over $\left[0, L_{\text{equivalent}}\right]$, and

$\text{M}_2\left(x\right)$ over $\left[L_{\text{equivalent}}, 10L_{\text{equivalent}}\right]$

$M_{\max}$ is maximum of the absolute value of the above bending moments.

6- Calculate:

$$\sigma_{\text{Lb_live}} = \frac{M_{\max} \cdot D}{2I}, \ \text{psi} \tag{31}$$

The longitudinal live load is the sum of the local and global bending terms:

$$\sigma_{\text{L_live}} = \sigma_{\text{Llb_live}} + \sigma_{\text{Lb_live}} \tag{32}$$

APPENDIX F – FAILURE ASSESSMENT DIAGRAM

Failures of volumetric flaws under static loading occur when the highest stress in the flawed component ($\sigma_{component}$) equals the material stress limit ($\sigma_{material}$). This can be expressed mathematically as:

$$\sigma_{component} = \sigma_{material} \tag{33}$$

Hence, any fitness-for-service analysis of a flawed component consists in determining the factors that go into evaluating the component stress and fracture mechanics parameters and comparing them with the appropriate material parameter. This holds true for both time independent (static) and time dependent failures.

Corrosion is the most common blunt imperfection encountered in pipelines. Under normal circumstances blunt imperfections fail by the mechanism of plastic collapse (*i.e.* general yielding of the cross section). The failure criterion for this type of imperfection is shown in Equation (18) The general equation used for the analysis of an axially oriented blunt imperfection has the form:

$$\sigma_{\text{fail}} = \bar{\sigma} \frac{1 - \left(\frac{A}{A_0}\right)}{1 - \left(\frac{1}{M_t}\right)\left(\frac{A}{A_0}\right)} \tag{34}$$

$$M_t = \sqrt{\frac{1.02 + 0.4411\lambda^2 + 0.006124\lambda^4}{1.0 + 0.02642\lambda^2 + 1.533\times10^{-6}\lambda^4}} \tag{35}$$

$$\lambda = \frac{0.909 L_a}{\sqrt{0.5Dt}} \tag{36}$$

where

σ_{fail} is the failure stress for the imperfection,

$\bar{\sigma}$ is the flow stress for the material,

A is the area of metal loss,

A_0 is the area in the region of metal loss before the metal loss and

M_t is the Folias correction for bulging associated with pressuring a pipe containing a longitudinal through wall crack,

La is the axial length of the imperfection,

D is the pipe diameter and

t is the pipe wall thickness.

The flow stress can be determined as the yield stress plus 69 MPa (10,000 psi) or as the average of the yield stress and the ultimate tensile stress. If we assume that the imperfection area has a given shape, Equation (34) takes the following form:

$$\sigma_{\text{fail}} = \bar{\sigma} \frac{1 - C\left(\frac{a}{t}\right)}{1 - C\left(\frac{a}{t}\right)\left(\frac{1}{M_t}\right)} \tag{37}$$

where

C is a shape factor that equals 1 for a rectangular shape or 2/3 for a parabolic shape. The value of 0.85 has been found to give the best fit to test data for corrosion.

a is the imperfection depth.

The Folias correction in Equation (35) is from API 579 [55]. A brief history of the development of Equations (34) through (37) can be found in Reference [67]. Historically the referenced equations have been used to determine the failure pressure of corroded pipe. In this case

$$\sigma_{\text{fail}} = \frac{P_{\text{fail}} \cdot D}{2t} \tag{38}$$

where P_{fail} is the failure pressure of the corroded pipe.

We recommend using Equation (37) with C equal to 0.85 for an initial assessment of a blunt metal loss imperfection if only the depth and length are known[17]. We can generalize the results given above in the following way. First, Equation (37) is reformulated in the form of Equation (33). The resulting equation is as follows:

$$\frac{1 - C\left(\frac{a}{t}\right)\left(\frac{1}{M_t}\right)}{1 - C\left(\frac{a}{t}\right)} \sigma_{\text{fail}} = \bar{\sigma} \tag{39}$$

[17] If multiple depth measurements are available, a more accurate assessment can be obtained using the effective area method. This method iterates through all possible subsets of the imperfection area based on the depth measurement and selects the area that gives the least failure stress [67].

The left hand side of Equation (39) is the stress in the material and the right side is the material limiting stress. σ_{fail} is the nominal stress due to pressure if the metal loss were not there and the left side of Equation (39) can be thought of as the stress concentration that results from the metal loss. Since the right hand side of Equation (39) is the material stress we can write it the following way:

$$\sigma = \frac{1 - C\left(\frac{a}{t}\right)\left(\frac{1}{M_t}\right)}{1 - C\left(\frac{a}{t}\right)} \sigma_{\text{nominal}} \tag{40}$$

where

σ is the stress in the area with metal loss and

$\sigma_{nominal}$ is the stress in the area if there were no metal loss.

The final step in the generalization is based on the fact that $\sigma_{nominal}$ is the membrane stress in the pipe wall that is caused by the internal pressure. If we assume that the stress is linear through the wall of the pipe, the membrane stress is the average stress through the wall thickness. When the stress distribution is linear, there is also a bending stress that is half of the difference between the stress on the outer diameter and the stress on the inner diameter. Bending stresses must be treated differently from membrane stresses. If the only stress in the component is a membrane stress, the component will fail when the stress in the component reaches the material limit. On the other hand, if the only stress is bending, it will only reach the limit on the inner and/or outer wall of the component and the remaining stresses in the component will be below the material limit. This is the result of the linear variation of the stress through the wall.

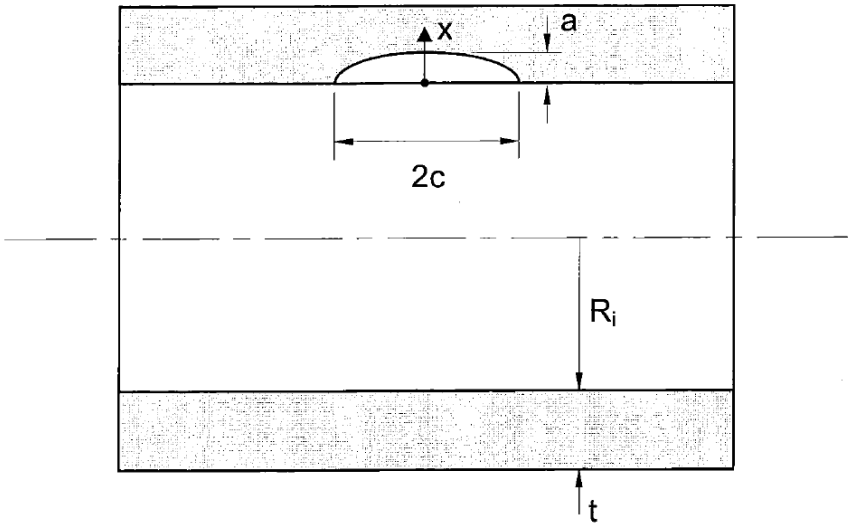
Once the nominal stress in the component has been separated into membrane and bending components, API 579 Appendix D Section D.5.11 [55] gives an equation for the plastic collapse of a longitudinally oriented semi-elliptical surface crack. This equation can be applied to any blunt metal loss imperfection that will fail by plastic collapse. The equation from API 579 is:

$$\sigma_{\text{hoop}} = \frac{1}{3(1\text{-}\alpha)^2}\left(\text{g}\cdot S_b + \sqrt{\left(\text{g}\cdot S_b\right)^2 + 9\left(\frac{1\text{-C}\left(\frac{a}{t}\right)\left(\frac{1}{M_t}\right)}{1\text{-C}\left(\frac{a}{t}\right)}\text{S}_m(1\text{-}\alpha)^2\right)^2}\right) \tag{41}$$

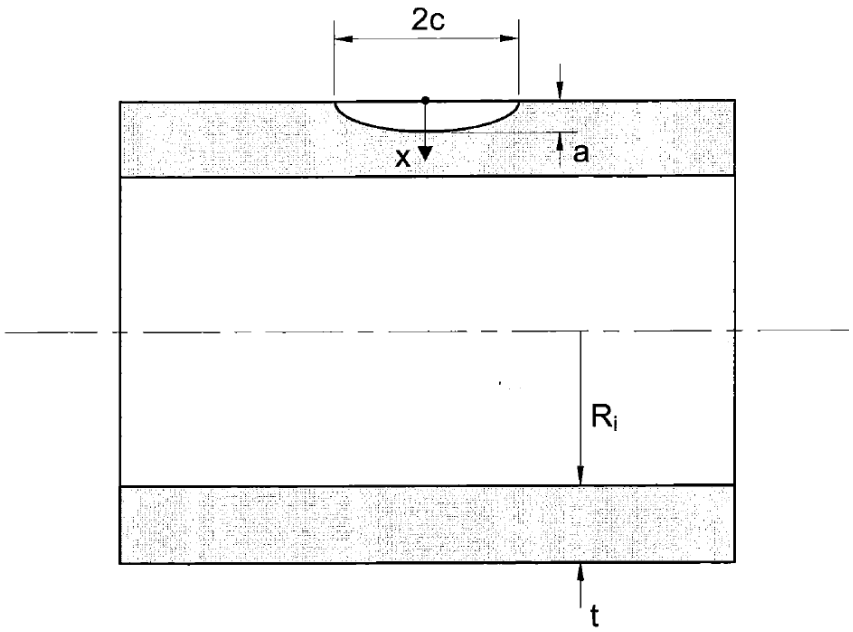
$$g = 1 - 20\left(\frac{a}{L_a}\right)^{0.75} \alpha^3 \tag{42}$$

$$\alpha = \frac{\left(\frac{a}{t}\right)}{1 + \left(\frac{2t}{L_a}\right)} \tag{43}$$

If S_b in Equation (41) is zero, the relation can be reduced to Equation (40). Generally, the additional hoop stress from outside forces such as surface loading and blasting are bending stresses that can be incorporated into a blunt imperfection stress analysis through Equation (41). The imperfection configuration for Equation (41) is shown in Figure F-1.



(a) Inside Surface



(b) Outside Surface

Figure F-1. Configuration of longitudinally oriented surface imperfection[18]

[18] L = 2c

When analyzing a gouge it is important to realize that there may also be a dent that developed during the gouging process. There is also the possibility that there are cracks in the base of the gouge that formed in the highly distorted metal in surface layer that is usually associated with gouging. The approach in the previous section can be used for gouges without dents or cracks if the pipe has an upper shelf Charpy v-notch impact energy greater than 21 J (16 ft-lb) [31]. A conservative approach to analyzing a gouge with cracks and no dent is to assume that the gouge with cracks in its base is a crack with a depth equal to that of the gouge plus the deepest crack. If there is the possibility of cracking but the depth of the cracks are unknown then it is recommended that 0.5 mm (0.02 inch) be added to the gouge depth to account for cracking at the base [31].

A quick assessment of an axial crack like feature can be made using the modified log-secant equation. The equation is [67]:

$$\sigma_{\text{fail}} = \left(\frac{\bar{\sigma}}{M_P}\right)\left(\frac{\text{arcos}(\text{e}^{-x})}{\text{arcos}(\text{e}^{-y})}\right) \tag{44}$$

$$x = \frac{\pi E\left(\frac{12CVN}{A_{CVN}}\right)}{4L\cdot\bar{\sigma}^2} \tag{45}$$

$$y = \frac{\pi E\left(\frac{12CVN}{A_{CVN}}\right)}{4L\cdot\bar{\sigma}^2\left(1-\left(\frac{d}{t}\right)^{0.8}\right)} \tag{46}$$

$$M_P = \frac{1-\left(\frac{A}{A_0}\right)\left(\frac{1}{M_t}\right)}{1-\left(\frac{A}{A_0}\right)} \tag{47}$$

where

σ_{fail} is the failure stress for the pipe with a crack,

$\bar{\sigma}$ is the flow stress for the material,

CVN is the Charpy v-notch energy of the material (ft-lbs),

A_{CVN} is the cross sectional area of the notched section of the CVN specimen (in),

E is the elastic modulus of the pipe steel,

d is the crack depth,

L is the crack length,

A is the area of the crack (= dL for a rectangular crack) and

A_0 is the initial cross sectional area of the cracked section (= tL for a rectangular crack).

M_t is calculated from Equation (35) using the crack parameters. Equation (44) through (47) are based on English units where the CVN is in ft-lbs and A_{CVN} is in in^2. Any self-consistent units can be used so long as the term $12CVN/A_{CNV}$ results in units of stress/length that is consistent with the other terms. Note that Equation (44) approaches Equation (40) as the CVN becomes large, i.e. failure occurs through plastic collapse as the toughness increases.

The solution in Equation (44) only holds for internal pressure. If there are other loadings such as through wall bending the crack must be analyzed using basic fracture mechanics. A fracture mechanics assessment requires knowledge of the fracture toughness (plane strain fracture toughness K_{IC}, J-integral J_{IC} or crack tip opening displacement δt_{crit}) of the material. The fracture toughness can be estimated from Charpy v-notch test results using the following equations:

$$K_{IC} = 8.47\left(CVN\right)^{0.63}, \left(\mathrm{MPa}\sqrt{\mathrm{m}}, \mathrm{Joules}\right) \tag{48}$$

$$K_{IC} = 9.35\left(CVN\right)^{0.63}, \left(\mathrm{ksi}\sqrt{\mathrm{in}}, \mathrm{ft\text{-}lbs}\right) \tag{49}$$

where

KIC is the plane strain fracture toughness of the material and

CVN is the Charpy v-notch toughness of the material.

Solutions for the stress intensity (K_I) for an axial surface cracked pipe can be found in Appendix C of API 579 [55]. The calculation of K_I depends on the use of tables of influence coefficients that are long and complicated to use for hand calculations. The solution for a surface cracked plate can be used to obtain a conservative estimate of K_I for and axially cracked pipe with a high D/t ratio if the membrane stress (σ_m) is multiplied by M_t (Equation (35)) for a through wall crack and M_P (Equation (47)) for a surface crack. The through wall crack calculation is important for determining if a surface crack will result in a leak or rupture when it breaks through the wall of the pipe.

The maximum stress intensity for the flat plate solution is:

$$K_1 = \left(M_m \sigma_m + M_b \sigma_b\right)\sqrt{\frac{\pi a}{Q}} \tag{50}$$

$$Q = 1.0 + 1.464\left(\frac{2a}{L}\right)^{1.65} \tag{51}$$

$$M_m = M_1 + M_2\left(\frac{a}{t}\right)^2 + M_3\left(\frac{a}{t}\right)^4 \tag{52}$$

$$M_1 = 1.13 - 0.09\left(\frac{2a}{L}\right) \tag{53}$$

$$M_2 = \frac{0.89}{0.2 + \left(\frac{2a}{L}\right)} - 0.54 \tag{54}$$

$$M_3 = 0.5 - \frac{1}{0.65 + \left(\frac{2a}{L}\right)} + 14\left(1 - \left(\frac{2a}{L}\right)\right)^{24} \tag{55}$$

$$M_b = M_m \cdot H \tag{56}$$

$$H = 1 + G_1\left(\frac{a}{t}\right) + G_2\left(\frac{a}{t}\right)^2 \tag{57}$$

$$G_1 = -1.22 - 0.12\left(\frac{2a}{L}\right) \tag{58}$$

$$G_2 = 0.55 - 1.05\left(\frac{2a}{L}\right)^{0.75} + 0.47\left(\frac{2a}{L}\right)^{1.5} \tag{59}$$

Equations (50) through (59) assume that the crack depth (a) is less than 0.5 of the crack length (L) and that the crack occurs on the outside surface of the pipe. If the crack occurs on the inside surface of the pipe the internal pressure (P) must be added to σ_m to account for the pressure on the crack surface. Generally, the additional hoop stress from outside forces such as surface loading and blasting are through-thickness bending stresses that can be incorporated into a crack stress intensity through Equation (50).

When using Equation (50), special attention must be exercised to distinguish the through-thickness bending stress from global section bending stress. Significant through-thickness bending moment can arise when external loads, such as a point load, act on the pipe.

If there is uncertainty about the failure mode of a crack-like imperfection the failure assessment diagram (FAD) approach can account for both fracture and plastic collapse. What follows is an abbreviated version of the FAD approach in API 579 [55]. The FAD approach is based on the following curve:

$$K = \left(1 - 0.14L^2\right)\left(0.3 + 0.7e^{(-0.65L^6)}\right) \quad \text{for } \mathrm{L} \le \mathrm{L}^P_{\mathrm{r(max)}} \tag{60}$$

where

$L^P_{r(\max)}$ is 1.00 for materials with yield point plateau (strain hardening exponent > 15), 1.15 for ASTM A508 or equivalent, 1.25 for C-Mn steels.

Figure F-2 shows a plot of the FAD curve.

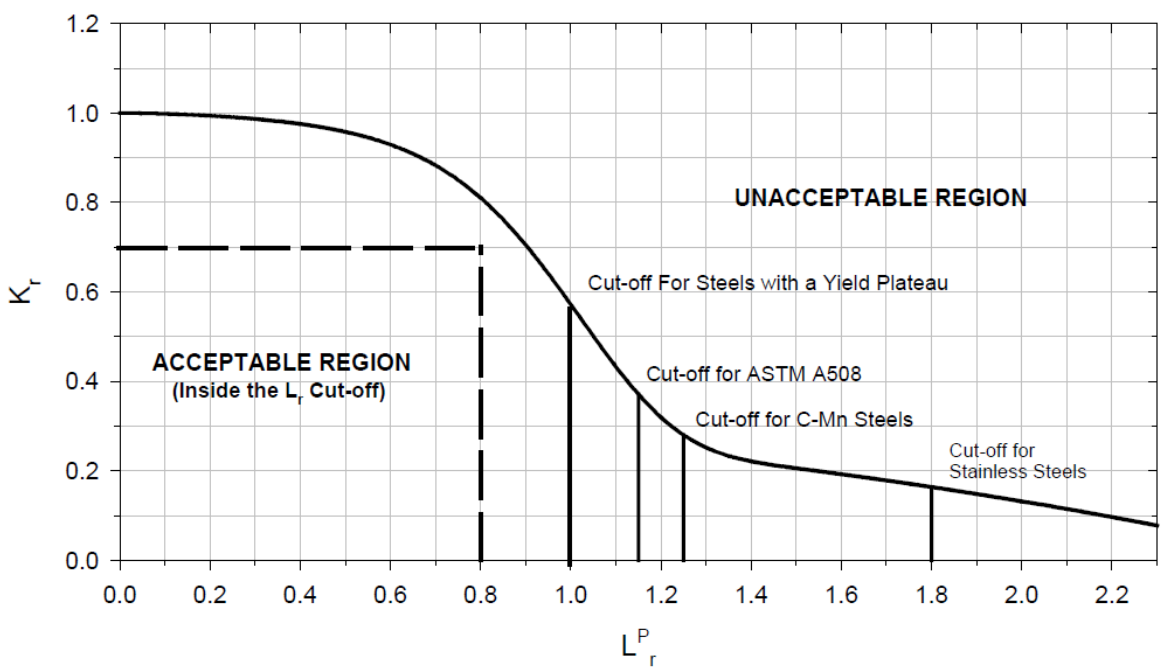


Figure F-2. Failure assessment diagram curve

The following quantities are calculated and plotted on the same diagram as the FAD curve:

$$L_r^P = \frac{\sigma_{\text{ref}}}{\sigma_{\text{yield}}} \tag{61}$$

$$K_r = \frac{K_I}{K_{\text{mat}}} \tag{62}$$

σ_{ref} in Equation (61) is calculated from Equation (40) or (41) and σ_{yield} is the yield strength for the material. If the actual yield strength is not known, then the specified minimum yield strength (SMYS) can be used. K_I is calculated from Equation (50) and K_{mat} can be estimated from the CVN value for the material using either Equation (48) or Equation (49), depending on the units used.

If the (L_r^P, K_r) pair lies under the FAD curve as shown by the rectangle in Figure F-2 then the imperfection is acceptable. If it lies on or outside of the rectangle, then it is not acceptable. The theory behind the FAD approach can be found in References [68] and [69].

APPENDIX G - MISALIGNMENT OF GIRTH WELD STRESS CONCENTRATION FACTOR

Misalignment of a girth weld can induce an extra bending stress in the longitudinal direction of the pipe at the presence of a longitudinal membrane stress. Equation (63) is the SCF for a miss-aligned girth weld [52]:

$$k_e = 1 + \left(\frac{3\delta_m}{t}\right) e^{\left(-\sqrt{\frac{t}{D}}\right)} \tag{63}$$

where

δ_m is the girth weld eccentricity (see Figure G-1),

t is pipe wall thickness, and

D is pipe OD.

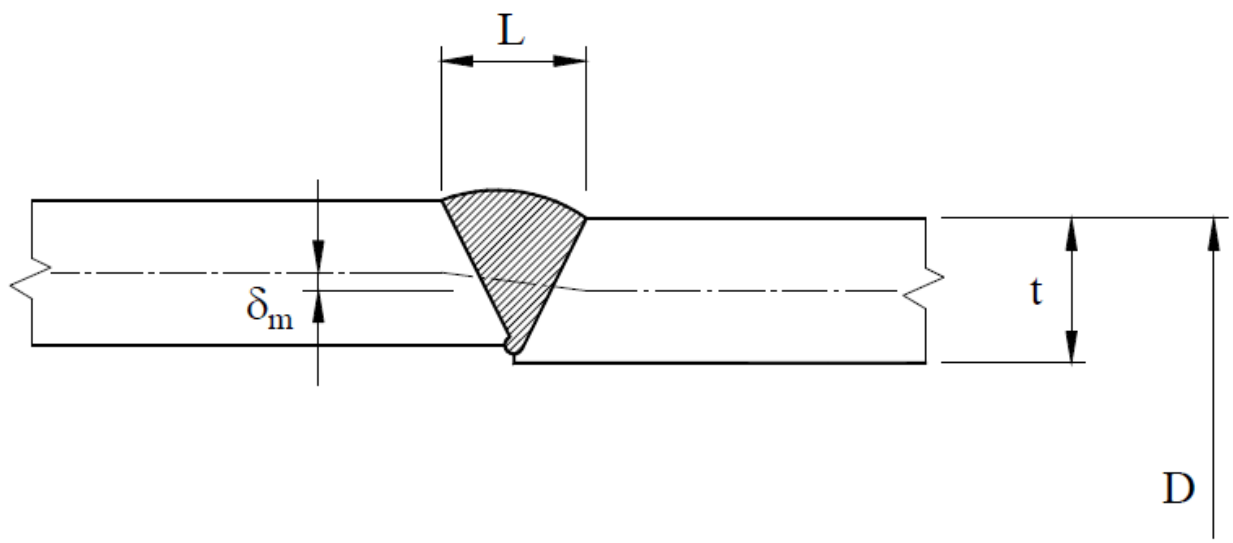


Figure G-1. Girth Weld Misalignment

Any consistent set of units can be used in Equation (63). Pipe ovality is usually the primary factor that causes girth weld misalignment; however, in some cases the pipe wall thickness tolerance can also become a comparable factor. The combined eccentricity from pipe ovality and thickness tolerance for a seamless pipe can be calculated as:

$$\delta_m = \sqrt{\delta_{\text{thickness}}^2 + \delta_{\text{ovality}}^2} \tag{64}$$

where

$\delta_{thickness}$ is calculated as $0.5(t_{max} - t_{min})$, and

$\delta_{ovality}$ is D_{max} - D_{min} if the pipes are supported during the construction in such a way to achieve a flush outside along one line,

$\delta_{ovality}$ is 0.5(D_{max} - D_{min}) if the pipes are centralized during construction, and

$\delta_{ovality}$ is 0.25(D_{max} - D_{min}) if the pipes are centralized and rotated during construction until a good fit is achieved.

The eccentricity should generally be calculated based on the maximum allowable tolerances, unless the actual eccentricity values are known from measurements. For quick assessment of a crack on an eccentric girth weld, the membrane and through-thickness stresses are calculated as:

$$\sigma_m = \sigma_{\text{m_nominal}} \tag{65}$$

$$\sigma_b = \sigma_{\text{b_nominal}} + (k_e - 1)\sigma_{\text{m_nominal}} \tag{66}$$

Failures of volumetric flaws under static loading

APPENDIX H - STRESS INTENSITY FACTOR AND LIMIT LOAD SOLUTION FOR BRANCH JUNCTION

A limit load solution for a branch connection under a bending moment that is applied to the branch has been proposed by Xuan et al [70]:

$$\frac{M_L}{M_0} = \frac{0.5\pi}{C\left(\left(f_1 \cdot A + 0.455 f_2 \cdot \kappa\sqrt{B}\right)^2 + 0.2385 B \cdot f_2^2 \cdot \kappa^2\right)^{0.5}} \tag{67}$$

$$f_1 = 1 + \frac{A^4}{3} \tag{68}$$

$$f_2 = 0.5\pi\left(1 - \frac{3}{16}A^2\right) \tag{69}$$

$$k = \frac{1}{1 + C^3} \tag{70}$$

$$A = \frac{R_b}{R_r} \tag{71}$$

$$B = \frac{2R_r}{t_r} \tag{72}$$

$$C = \frac{t_b}{t_r} \tag{73}$$

$$M_0 = 4\sigma_f \cdot R_b{}^2 \cdot t_b \tag{74}$$

where

R_b is the branch mean radius,

R_r is the run (main) mean radius,

t_b is the branch wall thickness,

t_r is the run wall thickness,

σ_f is the flow stress,

M_0 is the limit bending moment of a straight pipe calculated from Equation (74),

M_L is the limit bending moment for the branch.

Equation (67) can be generalized to develop a SCF for in-plane branch bending moment:

$$k_{\mathrm{BIM}} = \left(\frac{2C}{\pi}\right)\left(\left(f_1 \cdot A + 0.455 f_2 \cdot \kappa\sqrt{B}\right)^2 + 0.2385B \cdot f_2^2 \cdot \kappa^2\right)^{0.5} \tag{75}$$

Equation (75) provides the SCF for an in-plane bending moment that acts on the branch. The DNV-RP-C203 [52] stress concentration factors for tubular connections can be used for bending moments that act on the run.

$$\sigma_1 = k_{\mathrm{AC}} \cdot \sigma_a + k_{\mathrm{MIP}} \cdot \sigma_{\mathrm{by}} \tag{76}$$

$$\sigma_2 = \frac{1}{2}\left(k_{\mathrm{AC}} + k_{\mathrm{AS}}\right)\sigma_a + \frac{\sqrt{2}}{2} k_{\mathrm{MIP}} \cdot \sigma_{\mathrm{by}} - \frac{\sqrt{2}}{2} k_{\mathrm{MOP}} \cdot \sigma_{\mathrm{bz}} \tag{77}$$

$$\sigma_3 = k_{\mathrm{AS}} \cdot \sigma_a - k_{\mathrm{MOP}} \cdot \sigma_{\mathrm{bz}} \tag{78}$$

$$\sigma_4 = \frac{1}{2}\left(k_{\mathrm{AC}} + k_{\mathrm{AS}}\right)\sigma_a - \frac{\sqrt{2}}{2} k_{\mathrm{MIP}} \cdot \sigma_{\mathrm{by}} - \frac{\sqrt{2}}{2} k_{\mathrm{MOP}} \cdot \sigma_{\mathrm{bz}} \tag{79}$$

$$\sigma_5 = k_{\mathrm{AC}} \cdot \sigma_a - k_{\mathrm{MIP}} \cdot \sigma_{\mathrm{by}} \tag{80}$$

$$\sigma_6 = \frac{1}{2}\left(k_{\mathrm{AC}} + k_{\mathrm{AS}}\right)\sigma_a - \frac{\sqrt{2}}{2} k_{\mathrm{MIP}} \cdot \sigma_{\mathrm{by}} + \frac{\sqrt{2}}{2} k_{\mathrm{MOP}} \cdot \sigma_{\mathrm{bz}} \tag{81}$$

$$\sigma_7 = k_{\mathrm{AS}} \cdot \sigma_a + k_{\mathrm{MOP}} \cdot \sigma_{\mathrm{bz}} \tag{82}$$

$$\sigma_8 = \frac{1}{2}\left(k_{\mathrm{AC}} + k_{\mathrm{AS}}\right)\sigma_a + \frac{\sqrt{2}}{2} k_{\mathrm{MIP}} \cdot \sigma_{\mathrm{by}} + \frac{\sqrt{2}}{2} k_{\mathrm{MOP}} \cdot \sigma_{\mathrm{bz}} \tag{83}$$

where

sa, sby, and sbz are the axial, in-plane bending stress and out-of-plane bending stresses in the branch, respectively,

k_{AS} is the stress concentration factor at the saddle for the axial load,

k_{AC} is the stress concentration factor at the crown for the axial load,

k_{MIP} is the stress concentration factor for in-plane bending moment, and

k_{MOP} is the stress concentration factor for out-of-plane bending moment.

Figure H-1 shows the locations where the stresses are calculated and Figure H- 2 shows the geometry of the connection.

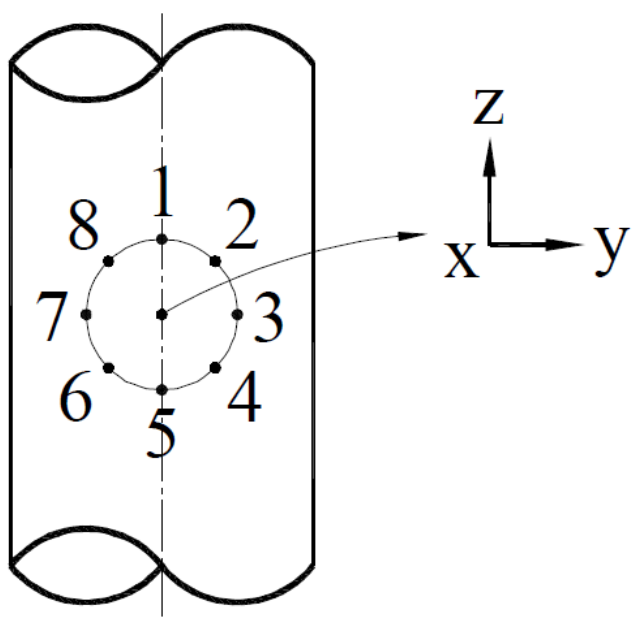


Figure H-1. Stress Evaluation Points for a Tubular Joint

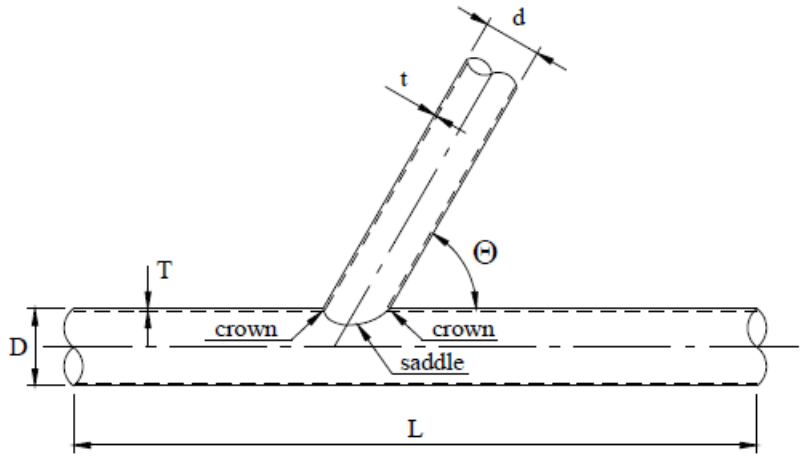


Figure H- 2. Geometrical Factors for Tubular Joint SCF Calculations

The stress concentration factors are calculated according to Appendix B of DNV-RP-C203 [52]:

Main SCF for axial stress at saddle:

$$k_{AS} = \gamma \cdot \tau^{1.1}\left(1.11 - 3\left(\beta - 0.52\right)^2\right)\left(\sin\theta\right)^{1.6} \tag{84}$$

Main SCF for axial stress at crown:

$$k_{AC} = \gamma^{0.2} \cdot \tau\left(2.65 + 5\left(\beta - 0.65\right)^2\right) + \beta \cdot \tau\left(0.25\alpha - 3\right)\sin\theta \tag{85}$$

Branch SCF for axial stress at saddle:

$$k = 1.3 + \gamma \cdot \tau^{0.52} \cdot \alpha^{0.1}\left(0.187 - 1.25\beta^{1.1}\left(\beta - 0.96\right)\right)\left(\sin\theta\right)^{2.7-0.01\alpha} \tag{86}$$

Branch SCF for axial stress at crown:

$$k = 3 + \gamma^{1.2}\left(0.12e^{(-4\beta)} + 0.011\beta^2 - 0.045\right) + \beta \cdot \tau\left(0.1\alpha - 1.2\right) \tag{87}$$

Main SCF for bending stress at crown (in-plane bending):

$$k_{\mathrm{MIP}} = 1.45\beta \cdot \tau^{0.85} \cdot \gamma^{(1-0.68\beta)}\left(\sin\theta\right)^{0.7} \tag{88}$$

Main SCF for bending stress at saddle (out-of-plane bending):

$$k = \gamma \cdot \tau \cdot \beta(1.7 - 1.05\beta^3)\left(\sin\theta\right)^{1.6} \tag{89}$$

Branch SCF for bending stress at crown (in-plane bending):

$$k = 1 + 0.65\beta \cdot \tau^{0.4} \cdot \gamma^{(1.09-0.77\beta)}\left(\sin\theta\right)^{0.06\gamma-1.16} \tag{90}$$

Branch SCF for bending stress at saddle (out-of-plane bending):

$$k = \tau^{0.46} \cdot \gamma^{0.95} \cdot \beta\left(0.99 - 0.47\beta + 0.08\beta^4\right)\left(1.7 - 1.05\beta^3\right)\left(\sin\theta\right)^{1.6} \tag{91}$$

where α, β, γ and τ are geometrical factors that are calculated as follows (see Figure H- 2):

$$\beta = \frac{d}{D} \tag{92}$$

$$\alpha = \frac{2L}{D} \tag{93}$$

$$\gamma = \frac{D}{2t_r} \tag{94}$$

$$\tau = \frac{t_b}{t_r} \tag{95}$$

where

t_r is run wall thickness,

t_b is branch wall thickness,

D is run OD, and

d is branch OD.

L is the length from the junction to a point at which the pipe will act as a longitudinal fixed support. L can be calculated from Equation (96):

$$L = \frac{\pi D \cdot t_r \cdot \sigma_y}{T_u} \tag{96}$$

where

σ_y is the yield strength, and

T_u is the longitudinal soil resistance and it can be estimated from the longitudinal soil-spring equations one presented in Appendix B of American Lifeline Alliance [26].

Equations (84) through (91) are based on elastic stress solutions and generally result in SCF values that are greater than those from plastic collapse solutions. These equations are only valid for the following ranges of geometrical parameters:

$$0.2 \le \beta \le 1.0$$

$$0.2 \le \tau \le 1.0$$

$$8 \le \gamma \le 32$$

$$4 \le \alpha \le 40$$

$$20^\circ \le \theta \le 90^\circ$$

Budden and Goodall [71] proposed the following equation for limit load of a pipe junction under internal pressure:

$$\frac{P_L}{P_0} = \frac{0.641\left(1+0.908\left(1-\frac{R_b}{R_r}\right)\right)\left(1-1.422\left(0.5-\frac{t_r}{R_r}\right)^2\right)}{1+0.608\left(1-\frac{t_b}{t_r}\right)} \tag{97}$$

where

t_r is run wall thickness,

t_b is branch wall thickness,

R_b is branch mean radius,

R_b is run mean radius,

P_L is the limit pressure of a pipe with imperfection, and

P_0 is the limit pressure of an intact pipe with no imperfection.

A SCF for the hoop stress under internal pressure can be defined based on Equation (97):

$$k = \frac{1 + 0.608\left(1 - \frac{t_b}{t_r}\right)}{0.641\left(1 + 0.908\left(1 - \frac{R_b}{R_r}\right)\right)\left(1 - 1.422\left(0.5 - \frac{t_r}{R_r}\right)^2\right)} \tag{98}$$

The branch connection SCF from Equations (84) through (98) are pertinent to a fabricated branch connection with no reinforcement. The equations can be applied to OLET type connection with caution. However, they may be overly conservative for standard welded Tee connection. The standard connections usually utilize a greater wall thickness at the connection to compensate for the lower pressure capacity; and curved fillets to reduce stress localization at the run-branch intersection. For SCF of standard pre-fabricated Tee-connections manufacturer's technical sheet and standards codes such as ASME B31.3 and ASME B31.8 can be consulted. Section C.8 of API 579 [55] recommends the following equation for stress intensity factor for a crack that is located at the corner of a branch connection (Figure H-3):

$$K_1 = 2.18 M_b \left(k_{\text{ta}} \cdot \sigma_{\text{nominal}} + P_c\right)\left(\frac{\sqrt{\pi\alpha}}{\pi}\right) \tag{99}$$

$$M_b = 1 + 0.15\left(\frac{a}{\sqrt{t_r^2 + t_b^2}}\right)^2 \tag{100}$$

$$k_{\text{ta}} = 1 + \left(k_{tn} - 1\right)\left(1 + \frac{1.414\pi\alpha}{2\left(d_b - t_b\right)}\right)^{-B} \tag{101}$$

$$B = 2.7 - 2\sqrt{\frac{t_b}{d_b}} \tag{102}$$

where

k_{ta} is the theoretical SCF that can be determined from the previous equations,

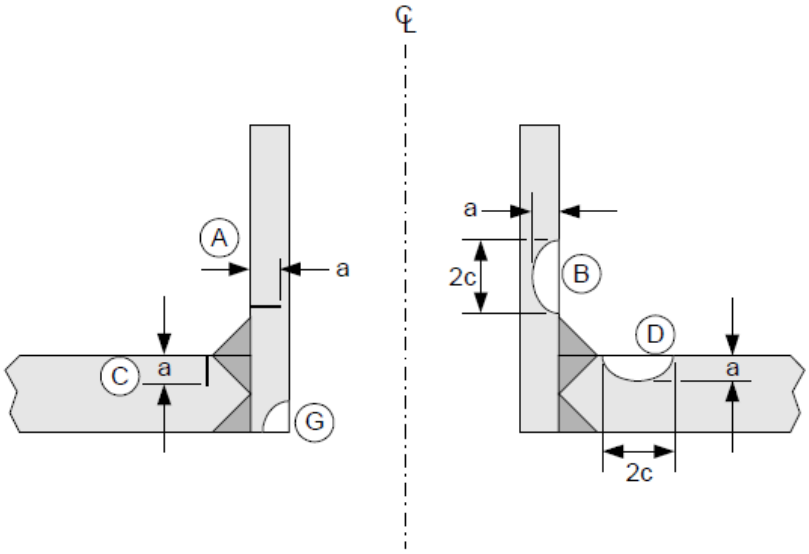
a is crack depth (Figure H-3),

t_r is run wall thickness,

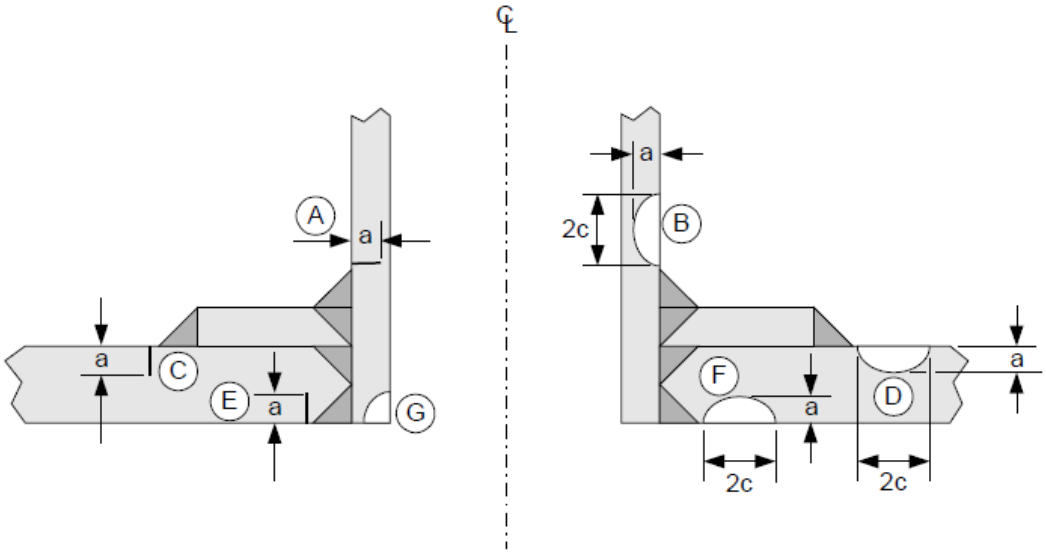
t_b is branch wall thickness,

d_b is mean branch diameter,

P_c is equal to the pipe internal pressure when the crack is exposed to the pressure and it is zero otherwise.



(a) Nozzle or Branch Connection



(b) Nozzle or Branch Connection with a Reinforcing Pad

Figure H-3. Cracks at Branch Connections [55]

APPENDIX I - STRESS INTENSITY FACTOR AND LIMIT LOAD SOLUTION FOR PIPE BENDS AND ELBOWS

According to Section C.7 and D.7 of API 579 [55] the stress intensity factors and limit load solutions of a straight pipe can be used for elbows and pipe bends as long as the stress values are determined taking into account the longitudinal pipe curvature. Section G.5.2 of BS 7910-2013 [72] provides the following limit load equations for elbows and pipe bends:

For hoop stress

$$\sigma_{\text{ref}} = 0.85\left(\frac{1-\frac{r}{2R}}{1-\frac{r}{R}}\right)\left(\frac{1-\left(\frac{a}{t}\right)\left(\frac{1}{M_t}\right)}{1-\frac{a}{t}}\right)\sigma_{\text{hoop}} \tag{103}$$

where

r is outside radius of pipe,

R is the bend radius at the centerline,

a is the imperfection depth,

Mt is the Folias surface correction for a longitudinal through wall crack.

A SCF for the hoop stress can be deduced by comparing Equation (103) and Equation (40):

$$k = 0.85\left(\frac{1-\frac{r}{2R}}{1-\frac{r}{R}}\right)k_1 \tag{104}$$

In the above equation k1 is the SCF for a straight pipe with a similar imperfection. The intensified membrane stress in the hoop direction is calculated as:

$$\sigma_m = k \cdot \sigma_{\text{m_nominal}} \tag{105}$$

The pipe longitudinal curvature does not have any significant effect on the burst pressure when a imperfection is oriented in the circumferential direction. Therefore, in the absent of a global longitudinal bending moment the SCF for axial stress is one. When a global axial moment is present the pipe cross-section undergoes ovalization and the stresses can change. The reference stress in the axial direction of an elbow or a pipe bend can be calculated as:

$$\sigma_{\text{ref}} = \left(\sigma_{\alpha} + 0.9 \left(\frac{r^2}{t \cdot R} \right)^{\frac{2}{3}} \left(\frac{4r}{\pi \left(r^4 - (r-t)^4 \right)} \right) M \right) \left(\frac{\pi \left(1 - \frac{a}{t} \right) + \frac{2a}{t} \sin \frac{c}{r}}{\left(1 - \frac{a}{t} \right) \left(\pi - \frac{c}{r} \cdot \frac{a}{t} \right)} \right) \tag{106}$$

where

M is the global in-plane bending moment,

c is the half crack length in the circumferential direction, and

D is pipe OD.

The second term on the right hand side of Equation (106) is the stress concentration factor that BS 7910 sets for a circumferential imperfection in a straight pipe. Therefore, intensified membrane stress under in-plane bending moment becomes:

$$\sigma_{\text{ref}} = \left(\sigma_{a} + 0.9 \left(\frac{r^2}{t \cdot R} \right)^{\frac{2}{3}} \left(\frac{4r}{\pi \left(r^4 - (r-t)^4 \right)} \right) M \right) k_1 \tag{107}$$

k_1 in the above equation is the imperfection SCF for a straight pipe with a similar imperfection. Since the effect of the in-plane bending is accounted for in Equation (107), k_1 can be determined without taking in to account the bending moment. As seen in the above equation, when no global bending moment acts on the pipe the stress concentration factor due to the bending curvature is one. Field bends that are formed by cold work can alter material properties (yield strength and fracture toughness). When the change in material properties can be quantified, the altered material properties shall be used in the assessment.

APPENDIX J - CRITERIA FOR FREEZE RUPTURE OF OPERATIONAL DEADLEGS

Operational deadlegs are sections of piping or pipelines that are stagnant due to temporary changes, repairs and operational reasons. Such deadlegs generally arise from modification over the course of the life of the asset. They are particularly susceptible to internal corrosion because water and other liquids and accumulate in low spots due to the absence of flow. Hence, corrosion management plans often require that the pipeline operators maintain a deadleg inventory or registry.

In cold weather regions with soil thawing horizontal deadlegs in pigging loops with water content and an inclination caused by soil subsidence are prone to freeze rupture. To generate a freeze rupture in a deadleg, all of the following requirements must be met:

1. The dead leg must be long enough and have sufficient slope such that a segment of the pipe can become fully filled with water.

2. The geometry of the dead leg must be such that the process fluid does not circulate sufficiently to keep the fluid in the deadleg above freezing.

3. A freeze plug must form in the deadleg between the flowing section and the blinded end of the deadleg, with liquid water between the ice plug and the blinded end.

4. The freeze plug, once formed, must be strong enough to hold against the pressure needed to rupture the pipeline.

The slope required to satisfy the first condition can be determined by simple trigonometry for a given pipe diameter and deadleg length. Table J-1 presents the slope required to have a transversal section of the pipe below the water line. Short deadlegs with large diameters would require the segment to sink more than 15 degrees, which would require excessive plastic deformation of the pipe, and hence is difficult to go unnoticed. On the other hand, long deadlegs (>6 ft) with medium to small diameters would require sinking just a few degrees to fill a transversal section with water; this is a condition that might prove difficult to detect.

Table J-1. Slope required for a deadleg having a transversal pipe section below the water line (Slope in Degrees)

Pipe Diam. (in)	Deadleg length (ft)			
	2	4	6	8
6	14.0	7.1	4.8	3.6
10	22.6	11.8	7.9	5.9
12	26.6	14.0	9.5	7.1

The third condition requires the freeze plug not forming close to the blinded end. Therefore, a segment of pipe long enough to accommodate the initial freeze plug and trapped water between the blind end and plug is required; Table J-2 presents the slope required to have a 1-foot long segment of the pipe below the water line, which might be considered enough to satisfy this condition.

Table J-2. Slope required for a deadleg having a 1-foot-long pipe segment below the water line (Slope in Degrees)

Pipe Diam. (in)	Deadleg length (ft)			
	2	4	6	8
6	26.6	9.5	5.7	4.1
10	39.8	15.5	9.5	6.8
12	45.0	18.4	11.3	8.1

Short deadlegs (<4 ft. long) would require inclinations that would be very noticeable and would possibly provoke excessive plastic deformation. Long deadlegs (>6 ft.) with medium to small diameters would require sinking more than 5° to fill a 1-foot segment with water. This makes the detection of the anomalous condition easier.

Finally, the second condition requires performing simple heat flow calculations specific to the system. The analysis would require the pipe material properties, the fluid physical properties, the flowrate near the deadleg, the operating temperature and the ambient temperature. If the circulation rate inside the deadleg is known, then length of the deadleg that would be maintained above freezing temperature can be calculated. If no circulation rate is assumed inside the deadleg, then length of the deadleg that would be maintained above freezing temperature can be calculated considering heat conduction through the steel pipe from a process fluid at the main line. It is important to consider any insulation of the deadleg in these calculations.

From the above considerations, it is proposed that the criteria for the freeze rupture threat should be based in the deadleg length.

APPENDIX K - INCORPORATING INTERACTIVE THREATS INTO RELATIVE RISK RANKING ALGORITHMS

In order to use the results of the interacting threats matrices produced for this work, the results need to be first normalized. The process by which the values are normalized is described in the following paragraphs. The significance of the number of failures due to interacting threats can only be considered by comparing them to the number of failures attributable to each threat independently. Thus, by this comparison the significance of the failures due to interacting threats can be quantified.

Overview of Normalizing Approach

Kiefner reviewed the DOT Reportable Incidents Database to identify failures where two or more threats interacted to cause the failure. The proposed approach to quantifying the increased likelihood of failure due to threat interactions is to compare the number of incidents and failures attributable to the interaction of threats to the number of incidents and failures due to only one of those threats. This approach attempts to normalize the number of failures due to interaction of threats to the number of failures due to one threat only.

The normalizing approach consists of:

- Compare each interacting threat to one of the individual threats. Identify one threat as the baseline (constant) and let the other threat be a variable. Determine how much additional probability (*i. e.,* increased failure frequency) is created by the variable threat.

- Use as much DOT incident data and other failure data as possible without sacrificing accuracy

Example of Normalizing Approach (EC + DPS)

The first step in evaluating the relative significance of a particular threat interaction would be to identify one of the threats as the baseline threat and the other as the influencing or variable threat. This system of defining roles in terms of risk relationships was utilized by Muhlbauer [73]. In most cases the baseline threat was associated with the driving factor or the primary cause of the failure and the other interacting threat represented a contributing condition or situation which in some way contributed to 1) a more rapid degradation of the pipe, 2) an increase stress or load on the pipe, or 3) a reduced tolerance of the pipe to the original flaw or loading condition.

In this illustrative case, we will examine the interacting threats of external corrosion (EC) and defective pipe seam (DPS) for natural gas transmission and gathering lines. The interaction can result in selective seam corrosion, a.k.a., grooving corrosion or preferential corrosion. Twenty-one incidents were attributable to this threat interaction in the DOT and Kiefner incident data. Selective seam corrosion is accelerated metal loss that can occur in the longitudinal seam of ERW and flashwelded pipe. This form of corrosion is considered to be more severe because 1)

the shape of the corrosion is often “notch like” representing a stress concentrator compared to typical pitting corrosion, 2) the corrosion occurs at an accelerated rate because of the properties of the pipe material at the seam, and 3) the toughness characteristics of the seam, particularly in pre-1970 low-frequency- and DC-welded ERW and flashweld pipe, can be poor. For selective seam corrosion, external corrosion is considered the driving factor since the same causes of external corrosion are required to initiate selective seam weld corrosion. The primary difference is related to the properties of the seam weld that is being corroded. The properties are an inherent or latent property associated with the pipe seam weld. Thus, the seam weld type is considered to be the variable threat.

In order to evaluate and quantify the significance of these 21 incidents, it is important to know how many failures were caused by external corrosion in total. The DOT incident data is available in several different spreadsheets. The PRCI Line Pipe Research Supervisory Committee sponsored three projects to review the incident statistics and reclassify them according to a new set of failure causes [74, 75, 76]. Table K-1 shows all of the available data.

The database showed that 262 incidents of external corrosion had been reported between 1985 and 2014. Since the interaction is associated with only ERW and flashwelded line pipe, failures that had occurred in seamless, DSAW, and lap-welded line pipe need to be omitted, leaving 156 failures due to external corrosion in pipe reported to be ERW, flashwelded, or unknown seam type. With these frequencies known, we could then determine that the interaction of EC and DPS resulted in an additional 21 failures that were not attributable to external corrosion alone. Thus the increase in likelihood of failure due to the interaction of these threats was calculated to be 21/156 or 13.5%.

Table K-1. Summary of DOT Reportable Incidents from 4 Sources

	1985-1997	1998-2000	2002-2009	2010-2011	2012-2014	Total
EC	109 ERW=70	22 ERW=8	96 ERW=58	9 ERW=6	26 ERW=14	262 ERW=156
IC	130 ERW=82	39 ERW=15	159 ERW=91	37 ERW=25	54 ERW=16	419 ERW=229
SCC	11	3	13	3	5	35
MFR	39 DP=15 DPS=24	4 DP=3 DPS=1	45 DP=27 DPS=18	7 DP=3 DPS=4	17 DP=9 DPS=8	112 DP=57 DPS=55
CON	84 DFW=20 DGW=23 CD=7 TSBPC=34 (CPLG=13)	22 DFW=7 DGW=7 CD=2 TSBPC=6 (CPLG=2)	92 DFW=32 DGW=36 CD=6 TSBPC=18 (CPLG=4)	27 DFW=3 DGW=8 CD=7 TSBPC=9 (CPLG=0)	42 DFW=10 DGW=9 CD=6 TSBPC=17 (CPLG=6)	267 DFW=72 DGW=83 CD=28 TSBPC=84 (CPLG=25)
EQ	119 MCRE=27 GF=15 SPPF=4 Other=73	23 MCRE=2 GF=5 SPPF=0 Other=16	104 MCRE=55 GF=15 SPPF=11 Other=23	23 MCRE=17 GF=0 SPPF=6 Other=0	101 MCRE=65 GF=10 SPPF=2 Other=24	370 MCRE=166 GF=45 SPPF=23 Other=136
IO	79	13	27	9	20	148
TPD	354 TP=308 PDP=40 V=6	59 TP=56 PDP=3 V=0	244 TP=231 PDP=9 V=4	50 TP=46 PDP=4 V=0	72 TP=63 PDP=8 V=1	779 TP=704 PDP=64 V=11
WROF	105 EM=24 HRF=58 LIGHT=14 CW=9	26 EM=11 HRF=5 LIGHT=8 CW=2	149 EM=25 HRF=108 LIGHT=12 CW=4	15 EM=2 HRF=3 LIGHT=6 CW=4	29 EM=9 HRF=5 LIGHT=7 CW=8	324 EM=71 HRF=179 LIGHT=47 CW=27
Total	1,030 incidents (80/yr)	211 incidents (70/yr)	929 incidents (116/yr)	180 incidents (90/yr)	366 incidents (122/yr)	2,716 incidents (94/yr)

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TERMS AND ABBREVIATION

API	American Petroleum Institute
ASME	American Association of Mechanical Engineers
CD	Construction Defect
CFR	Code of Federal Regulations
CON	Construction Related
CP	Cathodic Protection
CSA	Canadian Standards Association
CW	Cold Weather
DFW	Defective Fabrication Weld
DGW	Defective Girth Weld
DNV	Det Norske Veritas
DOT	Department of Transportation
DP	Defective Pipe
DPS	Defective Pipe Seam
EC	External Corrosion
EM	Earth Movement
EMAT	Electromagnetic Acoustic Transducer
EQ	Equipment Related
FAD	Failure Assessment Diagram
GAS	Natural Gas
GF	Gasket Failure
HL	Hazardous Liquids
HRF	Heavy Rains or Floods
IC	Internal Corrosion
ILI	In Line Inspection
IO	Incorrect Operations
ITD	In The Ditch
Kiefner	Kiefner and Associates, Inc.
LIGHT	Lighting
LoC	Loss of Containment
MCRE	Malfunctioning Pressure Control or Relief Equipment
MFL	Magnetic Flux Leakage
MFR	Manufacturing Related
MIC	Microbiological Induced Corrosion
NGA	Northeast Gas Association
OES	Optical Emission Spectography
PDAM	Pipeline Defect Assessment Manual
PDP	Previously Damaged Pipe
PMI	Positive Material Characterization
PPTS	Pipeline Performing Tracking System
SCADA	Supervisory Control And Data Acquisition

SCC	Stress Corrosion Cracking
SME	Subject Matter Expert
SPPF	Seal or Pump Packing Failure
SSWC	Selective Seam Weld Corrosion
TP	Third Party (includes First and Second Parties)
TPD	Third Party Damage
TSBPC	Threads Stripped or Broken Pipe Coupling
UTCD	Ultrasonic Crack Detection
V	Vandalism
WROF	Weather Related or Outside Force