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Prioritization of Offshore Pipeline Systems for Integrity Maintenance

AO

PIRAMID Technical Reference Manual No. 7.1

Confidential to C-FER's Pipeline Program Participants

Prepared by
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and
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C-FER Technologies Inc.

February 1998
Project 96009

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EXECUTIVE SUMMARY

C-FER Technologies Inc. (C-FER) is conducting a joint industry research program directed at the optimization of pipeline integrity maintenance activities using a risk-based approach. This document describes the system prioritization model that has been developed to estimate the level of operating risk associated with all segments within an offshore pipeline system. This model forms the basis for one of the modules in the software suite *PIRAMID* (Pipeline Risk Analysis for Maintenance and Integrity Decisions).

The offshore pipeline system prioritization approach involves the analysis of segment-specific pipeline attributes to produce firstly, an estimate of the probability of failure associated with individual segments as a function of failure cause, and secondly, an estimate of the potential consequences of segment failure in terms of three distinct consequence components (*i.e.,* life safety, environmental damage, and economic impact). The model then combines the cause-specific failure probability estimates with a global measure of the loss potential associated with the different consequence components into a single measure of operating risk for each pipeline segment. Segments are then ranked according to the estimated level of risk, the intention being to identify (or target) potentially high risk segments for subsequent detailed decision analysis at the maintenance optimization stage of the pipeline maintenance planning process.

Key steps in the pipeline system prioritization process are summarized as follows:

Probability Estimation

The annual probability of failure of each segment within the operating system is calculated for each significant failure cause from baseline historical failure rate estimates which are adjusted to reflect the impact of line-specific attribute sets. The specific failure causes addressed are: metal loss corrosion (external and internal); outside force (mechanical damage, natural hazards and ground movement); crack-like defects (stress corrosion cracking and girth weld fatigue cracks); and 'other'.

Baseline failure rates for a given pipeline type (*i.e.,* gas or liquid) are obtained from statistical analysis of historical pipeline incident data which yield estimates of the annual number of failure incidents per unit line length. The baseline failure rates are then converted to line-specific estimates using failure rate modification factors that depend on the attributes of the line segment in question. The failure rate modification factors are calculated from the values of selected segment attributes using algorithms developed from statistical analysis of pipeline incident data and/or analytical models supplemented where necessary by judgement. The resulting line-specific failure rates are then converted to failure probability estimates by multiplying each failure rate by the length of the corresponding line segment.

Consequence Analysis

The consequences of failure associated with a given segment are estimated using analytical models. The approach assumes that the consequences of pipeline failure are fully represented by three parameters: the *total cost* as a measure of the economic loss, the *number of fatalities* as a measure of losses in life, and the *residual spill volume* (after initial clean-up) as a measure of the long term environmental impact. The consequence assessment approach involves: modelling product release and subsequent movement; determination of the likely hazard types and their relative likelihood of occurrence; estimation of the hazard intensity at different locations; and calculation of the number of fatalities, the effective residual spill volume, and the total cost.

The three distinct consequence measures calculated using the models are combined into a single measure of the total loss potential associated with line failure by converting fatality estimates and residual spill volume estimates into equivalent costs. This conversion is carried out based on the so-called 'willingness to pay' concept which involves making an estimate of the amount of money that society would be willing to pay to avoid a particular adverse outcome.

Risk Estimation and Ranking

Multiplication of the segment-specific failure probability estimate for a given failure cause by the associated combined loss estimate (a financial cost estimate including the cost equivalent of human fatalities and residual spill volume) produces an estimate of operating risk defined as the expected annual loss associated with a given segment of pipeline for the failure cause in question. Summation of the risk estimates for all failure causes associated with a given segment gives an estimate of the total expected annual loss associated with segment operation. Dividing these segment risk estimates by the corresponding segment length yields normalized risk estimates that allow comparison of calculated risks between segments of different lengths. These cause-specific and combined-cause risk estimates form the basis for a quantitative ranking of all segments identified within a given pipeline system.

1.0 INTRODUCTION

1.1 Background

This document constitutes one of the deliverables associated C-FER's joint industry program on risk-based optimization of pipeline integrity maintenance activities. The goal of this program is to develop models and software tools that can assist pipeline operators in making optimal decisions regarding integrity maintenance activities for a given pipeline or pipeline segment. The software resulting from this joint industry program is called PIRAMID (Pipeline Risk Analysis for Maintenance and Inspection Decisions). This document is part of the technical reference manual for the program.

Implementation of a risk-based approach to maintenance planning, as envisioned in this program, requires quantitative estimates of both the probability of line failure and the adverse consequences associated with line failure should it occur. There is considerable uncertainty associated with the assessment of both the probability and consequences of line failure. To find the optimal set of integrity maintenance actions, in the presence of this uncertainty, a probabilistic optimization methodology based on the use of decision influence diagrams has been adopted. The basis for and development of this decision analysis approach is described in PIRAMID Technical Reference Manual No. 1.2 (Stephens *et al.* 1995). Application of the influence diagram based decision analysis approach to offshore pipeline systems is described in PIRAMID Technical Reference Manual No. 5.1 (Stephens *et al.* 1996).

Given the level of effort associated with the decision influence diagram approach to maintenance optimization, it is considered impractical and inefficient to carry out such a detailed analysis of candidate maintenance activities for all failure causes associated with each segment within a pipeline system. Alternatively, it is desirable to develop a pipeline system prioritization model that will estimate the level of operating risk associated with each segment within the system and to use this risk estimate as a basis for ranking segments. This segment ranking will serve to identify segments within the system with a potentially unacceptable level of operating risk with the intent that the high risk segments so identified can then be subjected to the more detailed analysis implicit in the decision influence diagram approach referred to above.

1.2 Objective and Scope

This document describes the system prioritization model that has been developed to estimate the level of operating risk associated with all segments within an offshore pipeline system. The approach involves the analysis of segment-specific pipeline attributes to produce firstly, an estimate of the failure rate associated with individual segments as a function of failure cause, and secondly, an estimate of the potential consequences of segment failure in terms of three distinct consequence components (*i.e.*, life safety, environmental damage, and economic impact). The model will then combine the cause-specific failure rate estimates with a global measure of the loss potential associated with the different consequence components into a single measure of operating risk for each pipeline segment, and then rank each segment, by failure cause, according to the calculated level of risk. This model will therefore serve as a screening tool that will help offshore pipeline regulators and operating companies identify potentially high risk segments for subsequent detailed analysis using the decision analysis tools that are currently being developed under this project.

The basic structure of the prioritization model described herein is based on the methodology developed in PIRAMID Technical Reference Manual No. 1.2 (Stephens *et al.* 1995). This document provides a detailed technical description of the prioritization approach and the underlying basis for the calculation of failure probabilities, individual and combined consequence components, and operating risk.

2.0 THE PRIORITIZATION METHOD

2.1 Overview

The framework for the pipeline integrity maintenance optimization as developed under this project is summarized in Figure 2.1. The first significant stage in the maintenance optimization process is to prioritize segments within a given pipeline system with respect to the need for integrity maintenance action. Specifically, the system prioritization stage is intended to rank segments based on the estimated level of operating risk associated with significant failure causes, where *risk* is defined as the product of the probability of line failure and a global measure of the adverse consequences of failure. To this end, pipeline characteristics (or attributes) must be evaluated to produce firstly, a line-specific estimate of the failure probability for each segment within the system as a function of failure cause (*e.g.*, metal loss corrosion; mechanical damage; ground movement; crack-like defects; *etc.*), and secondly, an estimate of the potential consequences of segment failure in terms of three distinct consequence components: life safety; environmental damage; and economic impact. Cause-specific failure probability estimates are then multiplied by a global measure of the loss potential associated with the different consequence components to produce a single measure of operating risk for all failure causes associated with each segment. Segments can then be ranked, by failure cause, according to the estimated level of risk. This cause specific segment ranking will serve to identify (or target) potentially high risk segments for subsequent detailed decision analysis at the maintenance optimization stage where the optimal strategy for managing the risk associated with a specific failure cause can be determined.

The steps associated with the prioritization process described above are summarized in the flowchart shown in Figure 2.2. The calculation process outlined in the flowchart can be divided into four distinct specification/calculation modules that perform the following functions:

- *System Definition.* defines the pipeline system to be analysed by specifying the segments to be considered and defining the attributes necessary to fully characterize each distinct section within each analysis segment.

- *Probability Estimation.* estimates the line-specific probability of failure, by failure cause, for each distinct section within each analysis segment.

- *Consequence Evaluation.* estimates the line-specific consequences of failure for each distinct section within each analysis segment.

- *Risk Estimation and Ranking.* calculates the operating risk associated with each segment within the system on a cause by cause basis and ranks the segments by the calculated level of operating risk on either a cause-by-cause or a combined cause basis.

An expanded description of each functional module is given in the following sections.

2.2 Model Components

2.2.1 System Definition

The extent of the pipeline system to be evaluated must first be defined. To this end, the pipeline system is divided into appropriate segments that can be treated as individual units with respect to integrity maintenance. For each segment the attributes that effect the probability and consequences of line failure are specified. Each segment should be as uniform as possible with respect to the attributes that affect pipe integrity (*e.g.*, age, material properties, coating type and environmental conditions). Alternatively, the segments may correspond to portions of the line for which the integrity maintenance actions being considered can be implemented (*e.g.*, if pigging is considered then a segment must be piggable and have pig traps at both ends). The preferred approach is subdivision by attribute commonality because the segment risk ranking results will then apply equally to all points along each segment. Where subdivision according to criteria other than attribute commonality is adopted, the segment ranking results will reflect an averaging process that accounts for variations in failure rates and failure consequences along the length of segments.

A detailed discussion of the System Definition model information requirements is given in Section 3.0.

2.2.2 Probability Estimation

The annual probability of failure of each segment within the operating system is calculated for each significant failure cause from baseline historical failure rate estimates which are adjusted to reflect the impact of line-specific attribute sets. The specific failure causes addressed are: metal loss corrosion (external and internal); outside force (mechanical damage, natural hazards and ground movement); crack-like defects (stress corrosion cracking and girth weld fatigue cracks); and 'other'.

Baseline failure rates for a given pipeline type (*i.e.*, gas or liquid) are obtained from statistical analysis of historical pipeline incident data which yield estimates of the annual number of failure incidents per unit line length. The baseline failure rates are then converted to line-specific estimates using failure rate modification factors that depend on the attributes of the line segment in question. The failure rate modification factors are calculated from the values of selected segment attributes using algorithms developed from statistical analysis of pipeline incident data and/or analytical models supplemented where necessary by judgement. The resulting line-specific failure rates are then converted to failure probability estimates by multiplying each failure rate by the length of the corresponding line segment.

A detailed discussion of the calculation process associated with the Probability Estimation model is given in Section 4.0.

2.2.3 Consequence Evaluation

The consequences of failure associated with a given segment are estimated using analytical models. The approach assumes that the consequences of pipeline failure are fully represented by three parameters: the *total cost* as a measure of the economic loss, the *number of fatalities* as a measure of losses in life, and the effective *residual spill volume* (after initial clean-up) as a measure of the long term environmental impact. The consequence assessment approach involves: modelling product release and subsequent movement; determination of the likely hazard types and their relative likelihood of occurrence; estimation of the hazard intensity at different locations; and calculation of the number of fatalities, the effective residual spill volume, and the total cost. The consequence models employed in the offshore system prioritization process have been adapted from the models previously developed for use in the decision analysis model based on influence diagrams (see PIRAMID Technical Reference Manual No. 5.1, Stephens *et al.* 1996).

The hazard types considered in the modelling process include both the immediate hazards associated with line failure (*e.g.*, jet/pool fires, vapour cloud fires or explosions, and toxic or asphyxiating clouds) as well as the long term environmental hazards associated with persistent liquid spills. Fatality estimation, based on the immediate hazard characterization models, reflects the population density associated with vessel traffic and offshore platforms and takes into account the effect of shelter and/or escape on survivability. Estimation of residual spill volume takes into account the movement and decay of persistent liquid spill products, the potential for offshore and onshore clean-up, and incorporates a factor that adjusts the residual volume measure to reflect both the environmental damage potential of the spilled product as well as the damage sensitivity of the coastal resources contacted by the spill. The total cost estimate includes: the direct costs associated with line failure including the cost of lost product, line repair, and service interruption; and the costs that are dependent on the type of release hazard including the cost of property damage, spill clean-up, and fatality compensation.

The three distinct consequence measures calculated using the models are combined into a single measure of the total loss potential associated with line failure by converting fatality estimates and residual spill volume estimates into equivalent costs. This conversion is carried out based on the so-called 'willingness to pay' concept which involves making an estimate of the amount of money that society would be willing to pay to avoid a particular adverse outcome.

A detailed discussion of the calculation process associated with the Consequence Evaluation model is given in Section 5.0.

2.2.4 Risk Estimation and Ranking

Multiplication of the segment-specific failure probability estimate for a given failure cause by the associated combined loss estimate (a financial cost estimate including the cost equivalent of human fatalities and residual spill volume) produces an estimate of operating risk defined as the expected annual loss associated with a given segment of pipeline for the failure cause in question. Summation of the risk estimates for all failure causes associated with a given segment gives an estimate of the total expected annual loss associated with segment operation. Dividing these segment risk estimates by the corresponding segment length yields normalized risk estimates that allow comparison of calculated risks between segments of different lengths. These cause-specific and combined-cause risk estimates form the basis for a quantitative ranking of all segments identified within a given pipeline system.

A detailed discussion of the calculation process associated with the Risk Estimation and Segment Ranking model is given in Section 6.0.

Figures

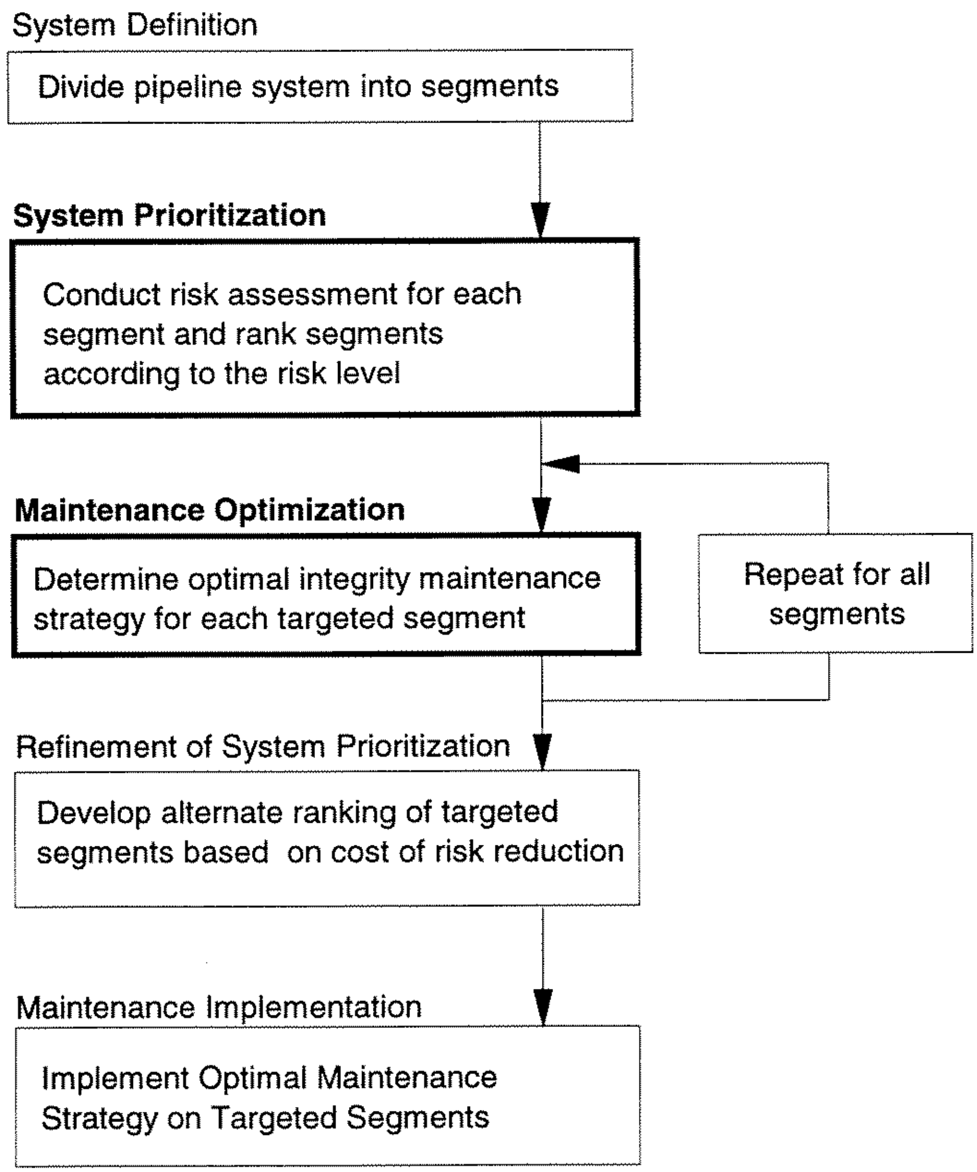

Figure 2.1 Framework for risk-based optimization of pipeline integrity maintenance activities

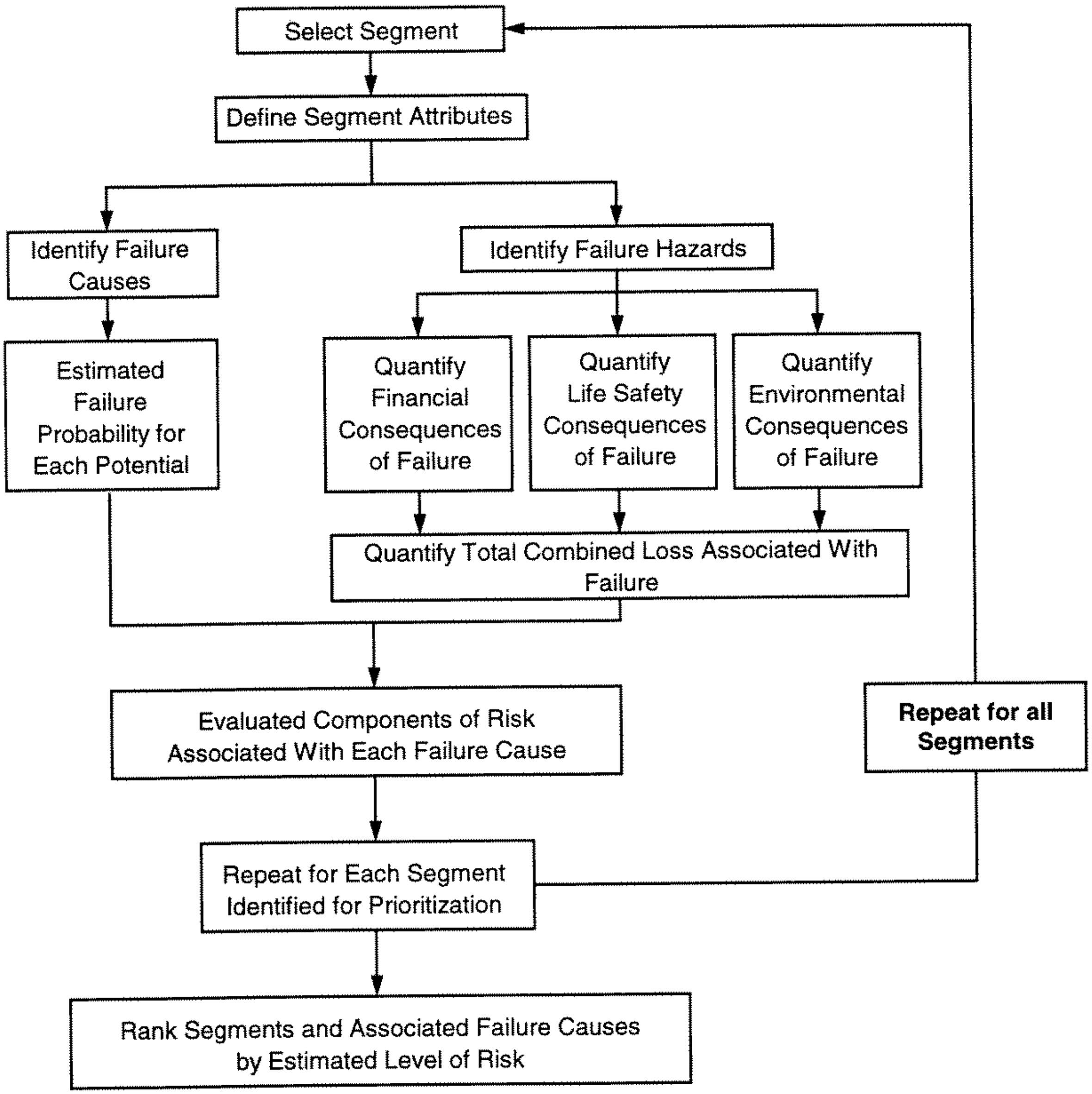

Figure 2.2 Flow chart for pipeline system prioritization

3.0 SYSTEM DEFINITION

3.1 Introduction

The pipeline system is defined by specifying the pipeline segments that are to be analysed and the required line attributes along the length of each analysis segment. This information will be processed to produce a description of each analysis segment that identifies consecutive sections within each segment (where a *section* is defined as a length of pipeline over which the attribute values do not vary) and defines the attribute set associated with each section.

3.2 Pipeline Attributes

The specific offshore pipeline attributes that have been chosen as a basis for segment prioritization are summarized in Table 3.1. The chosen attributes involve two overlapping sub-sets, one associated with parameters that have been shown to have an impact on the rate, and hence the probability, of line failure, and the other with parameters that are known to significantly influence the consequences of line failure should it occur. Table 3.1 identifies the specific attributes associated with each sub-set. Note that the total number of attributes that must be defined for each segment in a given system depends on the type of product (*i.e.*, natural gas, HVP liquid, or LVP liquid) being transported in the line and whether or not the environmental impact of persistent liquid product spills is to be considered in the consequence evaluation.

Note also that the attribute set employed for probability estimation and consequence evaluation at the prioritization stage is not intended to be comprehensive (*e.g.*, the pipeline literature suggests that line-specific failure rates are influenced by attributes not considered in the prioritization model). A restricted attribute set has purposely been employed at the system prioritization stage to limit the information requirements associated with the system prioritization activity. In addition, it is noted that the impact of additional factors on the probability and consequences of failure are addressed at the subsequent maintenance optimization stage where a more detailed estimate of operating risk is calculated as part of the formal decision analysis process conducted for the segments targeted by the initial risk ranking at the prioritization stage.

Tables

No.	Attribute Description	Attribute Name	Units ext (int)	Input Type	Required for Probability Estimation	Required for Consequence Estimation	Analysis Preferences: Natural Gas		Analysis Preferences: HVP liquids	Analysis Preferences: LVP liquids included	
							no condensate	w/ condensate	only	consider env.	suppress env.
1	Pipe Diameter	PipeDia	mm (m)	S1	X	X	X	X	X	X	X
2	Pipe Wall Thickness	PipeWall	mm (m)	S1	X	X	X	X	X	X	X
3	Pipe Body Yield Strength	PipeYield	MPa (Pa)	S1	X		X	X	X	X	X
4	Pipe Joint Type	JointType		S2	X		X	X	X	X	X
5	Line Age	LineAge	years	S1	X		X	X	X	X	X
6	Pipe Orientation	Orient	deg (rad)	S1		X	X	X	X	X	X
7	Line Elevation/Depth Profile (-ve sign implies depth)	Elev	m	C1	X	X	X	X	X	X	X
8	Operating Pressure Profile	Press	kPa (Pa)	C1	X	X	X	X	X	X	X
9	Longitudinal Stress Range	StressRange	MPa (Pa)	S1	X		X	X	X	X	X
10	Cumulative Number of Longitudinal Stress Cycles	StressCycle		S1	X		X	X	X	X	X
11	Number of Pipe Free Spans	NSpan	/km (/m)	S1	X		X	X	X	X	X
12	Operating Temperature	LineTemp	°C (K)	S1	X	X	X	X	X	X	X
13	Product Flow Rate (sign denotes flow direction)	FlowRate	kg/s	S1		X	X	X	X	X	X
14	Line Volume (percentage of line capacity)	CapFraction	% (fraction)	S1		X	X	X	X	X	X
15	Billing Abatement Threshold (percentage of nominated volume)	BAT	% (fraction	S1		X	X	X	X	X	X
16	Product Transportation Distance	TransDist	km (m)	S1		X	X	X	X	X	X
17	Block Valve Spacing	ValveSpace	km (m)	S1		X	X	X	X	X	X
18	Time to Block Valve Spacing	TimeClose	min (sec)	S1		X	X	X	X	X	X
19	Detectable Release Volume	VolDetect	cu. m.	S1		X	X	X	X	X	X
20	Time to Leak Detection	TimeDetect	hrs (sec)	S1		X	X	X	X	X	X
21	Time to Leak Stoppage (from time of detection)	TimeStop	hrs (sec)	S1		X	X	X	X	X	X
22	Depth of cover	Cover		S2	X		X	X	X	X	X
23	Vessel Traffic Density	VesselDens		S2	X	X	X	X	X	X	X
24	Subsea Activity	SubSeaAct		S2	X		X	X	X	X	X
25	Seabed Environment Corrosivity	EnvCorrode		S2	X		X	X	X	X	X
26	SCC Potential of Soil Environment	SCCPot		S2	X		X	X	X	X	X
27	External Pipe Coating Type	ExtCoat		S2	X		X	X	X	X	X
28	External Pipe Coating Condition	CoatCond		S2	X		X	X	X	X	X
29	Cathodic Protection Level	CPLevel		S2	X		X	X	X	X	X
30	Product Corrosivity	ProdCorrode		S2	X		X	X	X	X	X
31	Ground Movement Potential	GndMovPot		S2	X		X	X	X	X	X
32	Pipe Fail Potential given Ground Movement	GndFailPot		S2	X		X	X	X	X	X
33	Depth Range (calculated from elevation/depth profile)	DepthRange		S2	X	X	X	X	X	X	X
34	Adjacent Platform Type	PlatType		P1a		X	X	X	X	X	X
	Adjacent Platform Offset	PlatOffset	m	P1b							
35	Spill Trajectory Launch Zones	LaunchZone		S3		X		X		X	X
36	Susceptible Coastal Resources	Resource		P2a		X		X		X	X
	Coastal Resource Shoreline Types	ShoreType		P2b							
37	Coastal Resource Impact Probability	ImpactLoc		P3		X		X		X	X
38	Coastal Resource Impact Time	ImpactTime		P4		X		X		X	X

Attribute Data Input Type

S1 all consecutive sections delineated by KP start & KP end, defined by numeric value
S2 all consecutive sections delineated by KP start & KP end, defined by text string from predefined choice list
S3 all consecutive sections delineated by KP start & KP end, defined by an index value associated with a user defined text string
C1 continuously varying quantity defined by numeric values at KP reference locations
P1 selected locations defined by: a) an index value associated with a text string from a predefined choice list and b) a numeric value
P2 selected locations defined by: a) an index value associated with a user defined text string and b) an index value associated with a text string from a predefined choice list
P3 all user defined locations defined by a numeric value
P4 all user defined locations defined by a probability distribution

Table 3.1 Pipeline segment attributes for prioritization

4.0 PROBABILITY ESTIMATION

4.1 Introduction

An estimate is required of the annual probability of failure for each section within each analysis segment as a function of failure cause. In addition, since the consequences of line failure will depend on the mode of failure (*i.e.*, leak or rupture), because the failure mode will affect product release and hazard characteristics (see Section 5.0), it is also necessary to estimate failure probability as a function of failure mode. The required mode- and cause-specific failure probabilities can be calculated from baseline failure rate estimates adjusted to reflect the impact of line specific attribute sets.

Baseline failure rate estimates for a given pipeline product class (*i.e.*, gas or liquid) can be estimated from historical pipeline incident data. These baseline failure rates can be converted to section-specific estimates using failure rate modification factors that are defined by failure mode and failure cause as a function of selected pipeline section attributes. The failure rate modification factors are calculated from the section attributes using algorithms developed from the analysis of historical pipeline incident data and expert judgement. The resulting section-specific failure rates can subsequently be converted into failure probability estimates by multiplying each failure rate by the length of the corresponding section.

4.2 Probability Estimation Model

4.2.1 General

The annual probability of failure Pf for each section j within each analysis segment i, as a function of failure mode k and failure cause l, can be calculated from the following:

$$Pf_{ijkl} = Rf_{ijkl} L\sec_{ij} \qquad \text{(per year)} \qquad [4.1]$$

where: Rf_{ijkl} = the failure rate associated with section j of segment i for failure mode k and failure cause l;

$Lsec_{ij}$ = the length of section j within segment i (km);

and

$$Rf_{ijkl} = Rfb_l MF_{kl} AF_{ijl} \qquad \text{(per km•year)} \qquad [4.2]$$

where: Rfb_l = the baseline failure rate for failure cause l (per km•year);

MF_{kl} = the relative probability or mode factor for failure mode k associated with cause l; and

AF_{ijl} = the failure rate modification factor for section j of segment i associated with failure cause l.

The specific failure modes (index k) considered by the probability estimation model are:

- small leaks($k = 1$);
- large leaks ($k = 2$); and
- ruptures ($k = 3$).

The significant failure causes (index l) addressed by the probability estimation model are:

- external metal loss corrosion ($l = 1$);
- internal metal loss corrosion ($l = 2$);
- mechanical damage ($l = 3$);
- natural hazard ($l = 4$);
- ground movement ($l = 5$);
- environmentally induced crack-like defects, specifically stress corrosion cracking ($l = 6$);
- mechanically induced crack-like defects, specifically seam weld fatigue ($l = 7$); and
- other ($l = 8$).

4.2.2 Baseline Failure Rates

The failure rate is defined as the annual number of incidents involving loss of containment divided by the length of pipeline in operation for the year in which incidents are reported. The baseline failure rate, *Rfb*, is defined herein as the average failure rate for a reference line segment associated with a particular pipeline system, operating company or industry sector (*i.e.*, gas or liquid). It is intended to reflect average conditions relating to construction, operation and maintenance practices. For a given pipeline system these baseline failure rate estimates are best obtained from operating company data if the system exposure (*i.e.*, the total length and age of the system) is sufficient to yield a statistically significant number of failure incidents. In the absence of appropriate company or system specific data, an estimate of the baseline failure rate can be obtained from historical pipeline incident and exposure data gathered and published by government regulatory agencies, industry associations, and consultants.

A review of offshore incident data for pipelines located in the Gulf of Mexico (in particular, MMS 1996) and statistical summary reports (Olender 1983, de la Mare and Bakouros 1994, and Jansen 1995) was carried out to develop a set of reference failure rates that could be taken to be representative of offshore gas and liquid petroleum product pipelines. The review supports a reference failure rate of approximately 1.0×10^{-3} per km•yr for gas and 2.0×10^{-3} per km•yr for liquid product pipelines.

The reference failure rates cited above are combined cause failure estimates. As part of the review of offshore incident data for pipelines located in the Gulf of Mexico (Mandke 1990, NRC 1994, and MMS 1996), estimates of the relative probabilities of failure for each significant failure cause were obtained. The data supports the following relative probability estimates for gas and liquid product lines:

Failure Cause	Relative Probability (Gas)	Relative Probability (Liquid)
External Metal Loss Corrosion	10%	13%
Internal Metal Loss Corrosion	44%	27%
Mechanical Damage	15%	23%
Natural Hazard Damage	8%	15%
Ground Movement	(see note)	(see note)
Environmentally Induced Cracks (stress corrosion cracking)	(see note)	(see note)
Mechanically Induced Cracks (girth weld fatigue)	(see note)	(see note)
Other (excluding mechanical components)	16%	14%

Note: values either not available for cause as defined, or too low to be significant in a general context.

Multiplying the reference failure rates by the relative failure probability estimates tabulated above leads to the cause-specific baseline failure rate estimates for gas and liquid product pipelines summarized in Table 4.1. Note that baseline values are not tabulated for causes involving ground movement and crack-like defects. This reflects the assumption that these failure causes are highly location or line specific (as opposed to being a common problem for all pipelines) and the associated failure rates are therefore not adequately characterized using the adjusted baseline failure rate approach described above. Instead, an approach to probability estimation that keys on the specific attributes of the line in question will be employed for these failure causes. The specific approach adopted for each of the three excepted failure causes will be described in the sections of the report that develop their respective attribute factor algorithms.

4.2.3 Failure Mode Factor

The relative probability of failure by small leak, large leak, or rupture will depend on the failure mechanism being considered. For example, metal loss corrosion failures are predominantly small leaks (*i.e.*, pin holes) whereas mechanical damage failures resulting from impact or anchoring typically involve a greater percentage of large leaks and ruptures.

In the context of this project, the distinction between the three failure modes is tied to the hole size, or more explicitly, the equivalent circular hole diameter. Onshore pipeline failure rate summaries that report failure mode data by equivalent hole size (*e.g.*, Fearnehough 1985, and EGIG 1993) typically define the transition from small leak to large leak by an equivalent hole diameter of 20 mm, and the transition between large leak and rupture by an equivalent diameter ranging from 80 mm (Fearnehough 1985) to the line diameter (EGIG 1993). Based on this approach to failure mode distinction, the above references suggest relative failure mode probabilities for onshore gas transmission pipelines in the following ranges:

Failure Cause	Small Leak	Large Leak	Rupture
Corrosion	85 to 95 %	5 to 10 %	0 to 5 %
External Interference/Natural Hazard	20 to 25 %	50 to 55 %	20 to 30 %
Ground Movement	10 to 20 %	35 to 45 %	35 to 45 %
Construction Defects / Material Failure	55 to 70 %	25 to 35 %	5 to 10 %
Other / Unknown	70 to 90 %	5 to 15 %	5 to 15 %

In the absence of similar failure mode data for offshore pipelines it is suggested that the above onshore pipeline range estimates be assumed to apply to both offshore gas and liquid product lines. Reference failure mode probability estimates based on this assumption are summarized in Table 4.1.

4.2.4 Failure Rate Modification Factors

The algorithms required to define the failure rate modification factor AF_{ijl} for each significant failure cause l, for a given section j of segment i, are developed in the following sections.

Where possible these algorithms are based on information specific to offshore pipelines. However a number of relationships and weighting factors developed for prioritizing onshore pipelines (see Stephens 1996) have been adopted herein because of the relatively limited amount of data relevant available from the offshore pipeline industry.

4.2.4.1 External Metal Loss Corrosion

Pipeline failure associated with external metal loss corrosion is typically the result of a loss of coating protection at locations where the surrounding environment supports a corrosion reaction. The factors that affect the susceptibility of a line to external corrosion include: the type and condition of the coating system; the level of cathodic protection; and the corrosivity of the surrounding environment. Also, the corrosivity of the environment and the general condition of the coating system are significantly affected by the operating temperature of the pipeline because high temperatures promote coating decay and accelerate chemical reactions. Because external corrosion is a time dependent mechanism, the extent of corrosion damage and its propensity to cause line failure will be significantly influenced by the duration of exposure (*i.e.,* the line age) and the thickness of the pipe wall that must be penetrated by the growing corrosion feature.

The failure rate modification factor developed to reflect the impact of these factors on the baseline external metal loss failure rate is

$$AF = K_{EC} \left[\frac{A}{D} (T + 17.8)^{2.28} \right] F_{CE} \;\; F_{CP} \;\; F_{CT} \;\; F_{CC} \qquad [4.3]$$

where: K_{EC} = model scaling factor;
A = line pipe age;
D = line pipe diameter;
T = line operating temperature
F_{CE} = environment corrosivity factor;
F_{CP} = cathodic protection factor;
F_{CT} = coating type factor; and
F_{CC} = coating condition factor.

The core relationship involving line age A, pipe diameter D, and operating temperature T (line attributes: **LineAge**, **PipeDia**, and **LineTemp** in Table 3.1) was developed from a multiple linear regression analysis of failure rate data for onshore hydrocarbon liquid pipelines operating in California published by the California State Fire Marshall (CSFM 1993). The applicability of this relationship to offshore pipelines is directly supported by the results of regression analysis of failure rate data for offshore pipelines operating in the Gulf of Mexico (MMS 1996) which yielded essentially the same linear relationship between failure rate and the ratio of line age to line diameter. The applicability of the temperature adjustment term to offshore lines could not be verified due to a lack of data, however, the implied trend towards increased corrosion with increased temperature is generally supported by the offshore literature.

It should be noted that the pipe diameter term in the above relationship serves only as an indirect measure of the more relevant parameter, wall thickness. Pipe diameter is used rather than wall thickness for offshore lines because wall thickness is not commonly reported in available incident data and because a broadly applicable relationship between line diameter and wall thickness was not identified. This suggests that if a line segment has a wall thickness that is atypical, given its diameter, then this relationship may yield misleading results.

The environment corrosivity factor F_{CE} (line attribute **EnvCorrode** in Table 3.1) is an index that scales the rate modification factor over a range that reflects the impact of variations in seabed conditions on the corrosion failure rate. The index multiplier associated with each value of the environment corrosivity attribute is given by the following:

F_{CE}	Environment Corrosivity	Seabed Characterization
0.33	very low	Sand or Rock (low/medium organics)
0.67	low	Sand or Rock (high organics)
1.0	moderate	Mud (low organics)
2.3	high	Mud (medium organics)
3.3	very high	Mud (high organics) / Exposed Pipe

The suggested categories were adapted from a seabed corrosivity ranking scheme developed by King for North Sea sediments (King 1980). The order of magnitude range on index values is consistent with the results of corrosion metal loss tests conducted on steel pipe samples buried in soils of varying corrosivity as reported by Crews (1976). The specific index values for each category were established subjectively to reflect the perceived impact of seabed characteristics on the absolute corrosion rate.

The cathodic protection factor F_{CP} (line attribute **CPlevel** in Table 3.1) is an index that scales the rate modification factor over a range that reflects the impact of varying degrees of cathodic protection system effectiveness on corrosion failure rate. The index multiplier associated with each value of the cathodic protection level attribute is given by the following:

F_{CP}	Cathodic Protection Level	Characterization
0.5	above average	adequate voltage, uniform level
1.0	average	adequate average voltage, some variability
3.0	below average	inadequate voltage and/or high variability
5.0	no cathodic protection	———

The order of magnitude range was established primarily based on the failure rate data for onshore pipelines reported by the CSFM (1993) which indicates a failure rate approximately five times higher for unprotected pipe. The 0.5 and 3.0 factors were introduced based on judgment to reflect the fact that the five fold reduction in failure rate is an average value which therefore applies to pipelines having average cathodic protection levels and that some allowance should be made for above and below average conditions.

The coating type factor F_{CT} (line attribute **ExtCoat** in Table 3.1) is an index that scales the rate modification factor to reflect the impact of different coating types on corrosion failure rate. The index multiplier associated with each coating type is given by the following:

F_{CT}	Coating Type
0.5	polyethylene / epoxy
1.0	coal tar
2.0	Asphalt
4.0	tape coat
8.0	none (bare pipe)

The reference coating types and the index multipliers were adapted from a study of onshore lines by Keifner *et al.* (1990) wherein index factors are cited based on the 'perceived track record' of generic coating types.

The coating condition factor F_{CC} (line attribute **CoatCond** in Table 3.1) is an index that scales the rate modification factor to reflect the impact of the condition of the external coating on corrosion failure rate. The index multiplier associated with each condition state is given by the following:

F_{CC}	Coating Condition
0.5	above average
1.0	average
2.0	below average

The coating condition states and associated indices were selected so that when taken together with the coating type factor described above, the product of the two coating factor indices will yield a set of multipliers that are similar to those proposed by Keifner *et al.* (1990) for the different coating types identified.

The combined effect of the external metal loss corrosion failure rate adjustment factors described above is shown in Table 4.2 which summarizes the relative rate factors for all possible combinations of: coating type, coating condition, soil corrosivity and cathodic protection level. While some of the individual factors were defined primarily on a subjective basis, it is considered that the exhibited trends are both reasonable and consistent with the limited amount of available corrosion failure rate data.

The model scale factor K_{EC} serves to adjust the failure rate modification factor to a value of unity for the *external corrosion reference segment* defined as the line segment associated with the reference value of all line attributes that influence the external metal loss failure rate estimate. The intention is that the baseline failure rate for external corrosion should apply directly to the reference segment (hence the need for a corresponding attribute modification factor of 1). The expression for K_{EC} is obtained by first rearranging Equation [4.3] and setting $AF = 1.0$ to give

$$K_{EC} = \frac{1}{\left[\frac{A}{D}(T+17.8)^{2.28}\right] F_{CE} \; F_{CP} \; F_{CT} \; F_{CC}} \qquad [4.4]$$

The value of external corrosion model scale factor is calculated using Equation [4.4] by substituting the values of all parameters that are associated with the reference segment. The reference segment parameter values should be developed in conjunction with the baseline failure rate estimate (see Section 4.2.2) on a pipeline system, operating company or industry basis, depending on the intended application of the model.

Based on a review of data for pipelines in the Gulf of Mexico (MMS 1996) and incident data summaries in the public domain (King 1980, MMS 1995) the following reference values are suggested as default values for the external corrosion reference segment:

- line age, **LineAge** = 21 years;
- pipe diameter, **PipeDia** = 343 mm;
- operating temperature, **LineTemp** = 20° C;
- environment corrosivity, **EnvCorrode** = Very High (F_{CE} = 3.3);
- cathodic protection, **CPlevel** = Average (F_{CP} = 1.0);
- coating type, **ExtCoating** = Coal Tar (F_{CT} = 1.0); and
- coating condition, **CoatCond** = Average (F_{CC} = 1.0).

The corresponding model scale factor is $K_{EC} = 1.253 \times 10^{-3}$.

4.2.4.2 Internal Metal Loss Corrosion

Pipeline failure associated with internal metal loss corrosion is primarily influenced by the corrosivity of the transported product. Like external corrosion, internal corrosion is a time dependent mechanism, the extent of corrosion damage and its propensity to cause line failure will therefore be significantly influenced by the duration of exposure (*i.e.*, the line age) and the thickness of the pipe wall that must be penetrated by the growing corrosion feature.

The failure rate modification factor developed to reflect the impact of these factors on the baseline internal metal loss failure rate is

$$AF = K_{IC} \left(\frac{A}{D}\right) F_{PC} \qquad [4.5]$$

where: K_{IC} = model scaling factor;
A = line pipe age;

D = line pipe diameter; and
F_{PC} = product corrosivity factor.

The core relationship involving line age A (line attribute **LineAge** in Table 3.1) and pipe diameter D (line attribute **PipeDia** in Table 3.1) was inferred from the model developed for external corrosion which suggests that the failure rate is directly proportional to line age and inversely proportional to wall thickness. It should be noted that the pipe diameter term in the above relationship serves only as an indirect measure of the more relevant parameter, wall thickness. Pipe diameter is used rather than wall thickness for offshore lines because wall thickness is not commonly reported in available incident data and because a broadly applicable relationship between line diameter and wall thickness was not identified. This suggests that if a line segment has a wall thickness that is atypical, given its diameter, then this relationship may yield misleading results.

The product corrosivity factor F_{PC} (line attribute **ProdCorrode** in Table 3.1) is an index that scales the rate modification factor over a range that reflects the impact of variations in product corrosivity on corrosion failure rate. The index multiplier associated with each value of the product corrosivity attribute is given by the following:

F_{PC}	Product Corrosivity	Growth Rate (mm/yr)
0.04	negligible	< 0.02
0.2	low	0.02 to 0.1
1.0	moderate	0.1 to 0.5
5.0	high	0.5 to 2.5
25.0	extreme	> 2.5

The index range was established based on the simple assumption that if the corrosion growth rate is essentially constant, and failure rate has been shown to be inversely proportional to wall thickness, then it follows that the failure rate will be directly proportional to pit depth growth rate. The index multipliers are therefore directly proportional to the assumed growth rates for each product category. The corrosion growth rate ranges associated with each product category are consistent with values that are generally accepted in the process piping industry.

The model scale factor K_{IC} serves to adjust the failure rate modification factor to a value of unity for the *internal corrosion reference segment* defined as the line segment associated with the reference value of all line attributes that influence the internal metal loss failure rate estimate. The intention is that the baseline failure rate for internal corrosion should apply directly to the reference segment (hence the need for a corresponding attribute modification factor of 1). The expression for K_{IC} is obtained by first rearranging Equation [4.5] and setting $AF = 1.0$ to give

$$K_{IC} = \frac{1}{\left(\frac{A}{D}\right) F_{PC}} \qquad [4.6]$$

The value of internal corrosion model scale factor is calculated using Equation [4.6] by substituting the values of all parameters that are associated with the reference segment. The reference segment parameter values should be developed in conjunction with the baseline failure rate estimate (see Section 4.2.2) on a pipeline system, operating company or industry basis, depending on the intended application of the model.

Based on a review of incident data summaries in the public domain the following reference values are suggested as default values for the internal corrosion reference segment:

- line age, **LineAge** = 21 years;
- pipe diameter, **PipeDia** = 343 mm; and
- product corrosivity, **ProdCorrode** = Moderate (F_{PC} = 1.0).

The corresponding model scale factor is $K_{IC} = 1.633 \times 10^{1}$.

4.2.4.3 Mechanical Damage

Mechanical damage incidents are typically caused by anchor drag, net snags, or direct impact. The potential for line failure depends on both the likelihood of mechanical interference and the subsequent likelihood of pipe failure given interference. The factors that affect the probability of a line being subjected to mechanical interference include: the density of vessel traffic and the nature of vessel activity; water depth and pipe burial depth. The potential for line failure given interference depends on the nature of the interference event and the resistance of the pipe to failure given impact.

The failure rate modification factor developed to reflect the influence of these factors on the baseline mechanical damage failure rate is

$$AF = K_{MD} \frac{1}{D^{0.72}} F_{MT} \; F_{MA} \; F_{MD} \; F_{MC} \qquad [4.7]$$

where: K_{MD} = model scaling factor;
D = line pipe diameter;
F_{MT} = vessel traffic density factor;
F_{MA} = subsea activity factor;
F_{MD} = water depth factor; and
F_{MC} = depth of cover factor.

Probability Estimation

The core relationship involving the pipe diameter (line attribute **PipeDia** in Table 3.1) was developed from regression analysis of anchoring and impact failure rate data for pipelines in the Gulf of Mexico (MMS 1996). In the context of the model developed herein, this implies that pipe diameter serves as the single overall measure of a pipelines resistance to failure given mechanical interference.

The vessel traffic density factor F_{MT} (line attribute **VesselDens** in Table 3.1) is an index that scales the rate modification factor to reflect the influence of the level of surface activity on the potential for line interference and subsequent failure. The index multiplier associated with each vessel traffic density category is given by the following:

F_{MT}	Vessel Traffic Density	Characterization
0.01	No Significant Traffic	No prescribed use
0.1	Low Traffic Density	Very light traffic or designated fishing zone
1.0	Moderate Traffic Density	Low to moderate volume shipping corridor
10.0	High Traffic Density	High volume shipping corridor

Vessel traffic density is generally thought to have a significant effect on the frequency with which a pipeline is subjected to mechanical interference, however, very little data is currently available to help define the appropriate relationship. Index values were therefore defined subjectively based on judgement to reflect the perceived impact of vessel traffic volume on the potential for interference causing failure. The index value range adopted assumes a direct correlation between surface traffic volume and interference frequency and an order of magnitude difference in vessel traffic volumes between traffic density categories.

The subsea activity factor F_{MA} (line attribute **SubSeaAct** in Table 3.1) is an index that scales the rate modification factor to reflect the effect of significant subsea activity on the potential for interference resulting from surface vessel traffic. The activity categories and associated index multipliers are given by the following:

F_{MA}	Subsea Activity	Characterization
1.0	No	No designated activity
10.0	Yes	Designated fishing or anchoring zone

In the absence of relevant historical incident data, the above index values were established subjectively based on judgement to reflect an assumed order of magnitude increase in interference frequency in areas where significant subsea activity is anticipated.

Probability Estimation

The water depth factor F_{MD} (line attribute **DepthRange** in Table 3.1) is an index that scales the rate modification factor to reflect the effect of water depth on the potential for interference resulting from surface and subsurface activity. The water depth range categories and associated index multipliers are given by the following:

F_{MD}	Water Depth Range
10	Shallow (less than 10 m)
2.0	Deep (10 to less than 60 m)
0.4	Deep (60 to less than 300 m)
0.1	Ultra-Deep (300 m or greater)

Again, water depth is thought to be a significant factor in establishing the frequency of mechanical interference, but very little data is currently available to define the relationship. Index values were therefore defined subjectively based on judgement to reflect the perceived impact of water depth on the potential for interference causing failure. The chosen index values imply an order of magnitude decrease in impact frequency between shallow and deep water and between deep and ultra-deep water categories. The deep water category has been further subdivided at the 60 m water depth mark (which corresponds to the depth below which pipe burial is typically not required) and the implied overall deep water index value of 1.0 was doubled for the less than 60 m category and approximately halved for the greater than 60 m category. (Note, the chosen deep water indices, in combination with the sediment cover indices, given below result in a fully buried pipeline operating in less than 60 m of water having the same adjusted impact frequency as an unburied line operating in more than 60 m of water.)

The depth of cover factor F_{MC} (line attribute **Cover** in Table 3.1) is an index that scales the rate modification factor to reflect the degree to which the line is protected from mechanical interference by sediment cover over the pipe. The depth of cover categories and index multipliers associated with each category are given by the following:

F_{MC}	Depth of Cover
1.0	None
0.5	Intermittent or partial cover
0.2	Continuous, significant cover

The above index values were defined subjectively based on judgement to reflect the perceived impact of soil cover on the potential for interference causing failure. The nonzero value adopted for continuous cover acknowledges that complete cover does not completely eliminate the potential for line interference. The assumed five-fold reduction in the frequency of interference events associated with significant cover vs. no cover is consistent with estimates of the reduction in mechanical damage frequency documented by the European Gas Pipeline Incident Data Group (EGIG 1993) for on shore buried pipelines having significant cover (greater than 1.2 m) vs. minimal cover (less than 0.6 m).

Finally, to acknowledge the influence of proximity to offshore facilities on the frequency of mechanical damage events, sections of pipeline located close to platforms (*i.e.*, falling within so-called 'platform safety zones', see line attribute **PlatType** in Table 3.1) are assigned a vessel traffic density factor, F_{MT}, of 1.0 (equivalent to moderate traffic density) and a subsea activity factor, F_{MA}, of 10.0 (implying significant subsea activity). This results in a ten-fold increase in the mechanical damage frequency estimate for line sections close to platforms when compared to reference scenarios involving either low density vessel traffic with significant subsea activity, or moderate density vessel traffic with no significant subsea activity. This increase in the damage frequency estimate is consistent with failure rate data reported by Jansen (1995) for open sea areas and areas within platform safety zones which indicates that the rate is approximately one order of magnitude higher within safety zones.

The combined effect of the mechanical damage failure rate adjustment factors described above is shown in Table 4.3 which summarizes the relative rate factors for all possible combinations of: vessel traffic density, subsurface activity, water depth and burial depth. While the individual factors were defined primarily on a subjective basis, it is considered that the exhibited trends are both reasonable and consistent with the limited amount of available mechanical damage failure rate data.

The model scale factor K_{MD} serves to adjust the failure rate modification factor to a value of unity for the *mechanical damage reference segment* defined as the line segment associated with the reference value of all line attributes that influence the mechanical damage failure rate estimate. The intention is that the baseline failure rate for mechanical damage should apply directly to the reference segment (hence the need for a corresponding attribute modification factor of 1). The expression for K_{MD} is obtained by first rearranging Equation [4.7] and setting $AF = 1.0$ to give

$$K_{MD} = \frac{D^{0.72}}{F_{MT}\ F_{MA}\ F_{MD}\ F_{MC}} \qquad [4.8]$$

The value of the mechanical damage model scale factor is calculated using Equation [4.8] by substituting the values of all parameters that are associated with the reference segment. The reference segment parameter values should be developed in conjunction with the baseline failure rate estimate (see Section 4.2.2) on a pipeline system, operating company or industry basis, depending on the intended application of the model.

Based on a review of incident data summaries in the public domain the following reference values are suggested as default values for the mechanical damage reference segment:

- pipe diameter, **PipeDia** = 343 mm;

- vessel traffic density, **VesselDens** = Low Traffic Density ($F_{MT} = 0.1$);
- subsea activity level, **SubSeaAct** = Designated Zone ($F_{MA} = 10.0$);
- water depth range, **DepthRange** = Deep: 10 to 60 m ($F_{MD} = 2.0$); and
- depth of cover, **Cover** = Intermittent / Partial Cover ($F_{MC} = 0.5$).

The corresponding model scale factor is $K_{MD} = 6.689 \times 10^1$.

4.2.4.4 Natural Hazard Damage

Natural hazard damage incidents are typically associated with severe storms. The corresponding pipeline failure mechanism is usually large deformation resulting from direct vessel impact or anchor drag or, for small diameter lines, deformations resulting from storm induced hydrodynamic forces.

The failure rate modification factor developed to reflect the influence of these factors on the baseline natural hazard damage failure rate is

$$AF = K_{NH} \frac{1}{D^{1.77}} \; F_{NT} \, F_{NA} \; F_{ND} \; F_{NC} \tag{4.9}$$

where: K_{NH} = model scaling factor;
D = line pipe diameter;
F_{NT} = vessel traffic density factor;
F_{NA} = subsea activity factor;
F_{ND} = water depth factor; and
F_{NC} = depth of cover factor.

The relationship has the same basic form as that developed for the Mechanical Damage failure cause (see Section 4.2.4.3). The similarity reflects the fact that both failure causes are primarily associated with mechanical interference, however, failures due to Natural Hazards are addressed separately because their root cause is different (*i.e.,* failure is linked to environmental conditions which provoke interference events). The core relationship involving pipe diameter D (line attribute **PipeDia** in Table 3.1) was developed from a regression analysis of failure rate data for pipelines operating in the Gulf of Mexico (MMS 1996). The remaining attribute factors are as defined in Section 4.2.4.3 (note F_{NT} corresponds to F_{MT}, etc.)

The model scale factor K_{NH} serves to adjust the failure rate modification factor to a value of unity for the *natural hazard reference segment* defined as the line segment associated with the reference value of all line attributes that influence the natural hazard failure rate estimate. The intention is that the baseline failure rate for natural hazards should apply directly to the reference segment (hence the need for a corresponding attribute modification factor of 1). The expression for K_{NH} is obtained by first rearranging Equation [4.9] and setting $AF = 1.0$ to give

Probability Estimation

$$K_{NH} = \frac{D^{1.77}}{F_{NT}\ F_{NA}\ F_{ND}\ F_{NC}} \qquad [4.10]$$

The value of the natural hazard model scale factor is calculated using Equation [4.10] by substituting the values of all parameters that are associated with the reference segment. The reference segment parameter values should be developed in conjunction with the baseline failure rate estimate (see Section 4.2.2) on a pipeline system, operating company or industry basis, depending on the intended application of the model.

Based on a review of incident data summaries in the public domain the following reference values are suggested as default values for the natural hazard reference segment:

- pipe diameter, **PipeDia** = 343 mm;
- vessel traffic density, **VesselDens** = Low Traffic Density (F_{MT} = 0.1);
- subsea activity level, **SubSeaAct** = Designated Zone (F_{MA} = 10.0);
- water depth range, **DepthRange** = Deep: 10 to 60 m (F_{MD} = 2.0); and
- depth of cover, **Cover** = Intermittent / Partial Cover (F_{MC} = 0.5).

The corresponding model scale factor is $K_{NH} = 3.072 \times 10^4$.

4.2.4.5 Ground Movement

Pipeline failure can occur as a result of ground movement caused by, for example: slope movement and seismic activity. The potential for line failure due to ground movement depends on both the likelihood and extent of movement and the subsequent likelihood of pipe failure given ground movement. Failures due to ground movement events are highly location and pipeline specific and therefore, probability estimation based on historical incident rates adjusted by selected line attributes is not considered appropriate. Alternatively, an approach based entirely on location specific information is employed. Specifically, pipeline failure associated with ground movement will be addressed by directly specifying estimates of both the probability of a ground movement event, and the probability of line failure given event occurrence. These estimates will be inferred directly from the corresponding line attributes.

The failure rate modification factor developed to reflect this approach is

$$AF = R_{MV}\, P_{F|M}\, F_{JNT} \qquad [4.11]$$

where: R_{MV} = annual rate of significant ground movement events;
$P_{F|M}$ = probability of pipe failure given movement event; and
F_{JNT} = pipe joint factor.

Probability Estimation

Note that for the reasons stated above, this parameter will be multiplied by a fixed baseline failure rate estimate of unity, hence the calculated value of AF represents the estimated failure rate due to ground movement.

The rate of occurrence of a significant ground movement event, R_{MV} (line attribute **GndMovPot** in Table 3.1), is given by

R_{MV}	Rate Estimate (events / km year)
0.00001	Negligible (≤ 1 in 100,000)
0.0001	Low (1 in 10,000)
0.001	Moderate (1 in 1000)
0.01	High (1 in 100)
0.1	Extreme (≥ 1 in 10)

The rate estimates associated with each category were established subjectively based on judgement to provide a usable range of values that should be sufficient to characterize most situations of interest. Note that for line sections containing a single significant ground movement site, the rate estimate would be the annual event probability divided by the section length.

The probability of pipeline failure given ground movement, P_{FM} (line attribute **GndFailPot** in Table 3.1), is given by

P_{FM}	Failure Probability (per event)
0.01	Low (≤ 1 in 100)
0.1	Moderate (1 in 10)
1.0	High (1 in 1)

Again, the probability estimates associated with each category were established subjectively based on judgement to provide a usable range of values that should be sufficient to characterize situations of interest.

The pipe joint factor F_{JNT} (line attribute **JointType** in Table 3.1) is an index that modifies the estimate of the probability of failure given movement to reflect the impact of girth weld quality. The index multiplier associated with each joint type is given by the following:

F_{JNT}	Joint Type
0.5	High quality weld
1.0	Average quality weld
2.0	Poor quality weld
5.0	Mechanical joint

The index multiplier associated with each joint type was established subjectively based on judgement to reflect the perceived effect on failure probability of variations in the strength and ductility of different joint types.

4.2.4.6 Environmentally Induced Crack-Like Defects (stress corrosion cracking)

At the current stage of program development, pipeline failure associated with environmentally induced crack-like defects is restricted to the consideration of stress corrosion cracking (SCC) only. SCC tends to occur in highly stressed regions of pipe that are also experiencing external metal loss corrosion. The factors that are thought to affect the susceptibility of a line to SCC include all of the factors that influence the lines susceptibility to external metal loss corrosion plus: an environment conducive to SCC, an operating pressure that generates a hoop stress in excess of the so-called threshold stress for SCC, and the presence of a cyclic component to the hoop stress.

The failure rate modification factor developed to reflect the impact of these factors on the rate of SCC failure is

$$AF = \left[K_{EC} \left[\frac{A}{D} (T + 17.8)^{2.28} \right] F_{CE} \;\; F_{CP} \;\; F_{CT} \;\; F_{CC} \right] F_{SCC}\, F_{TH}\, F_{CPF}$$

$$= \left[AF_{for\ external\ metal\ loss\ corrosion} \right] F_{SCC} \;\; F_{TH} \;\; F_{CPF} \qquad [4.12]$$

where: F_{SCC} = SCC potential factor;
F_{TH} = threshold stress factor; and
F_{CPF} = supplemental cathodic protection factor.

The premise implicit in Equation [4.12] is that the SCC failure rate will be proportional to the external metal loss corrosion failure rate on the basis that an environment conducive to external metal loss corrosion must exist before SCC can develop. This suggests further that the baseline failure rate that is to be multiplied by the attribute factor defined above is that corresponding to external metal loss corrosion. Given these assumptions, the SCC specific attribute factors listed above therefore serve to define an SCC failure rate as some fractional multiple of the external metal loss corrosion rate. It is assumed that given the current lack of consensus on the mechanisms of SCC initiation and growth in line pipe, this simplistic and potentially conservative approach to failure rate estimation for the purposes of segment ranking represents a prudent interim strategy.

The SCC potential factor, F_{SCC}, (line attribute **SCCPot** in Table 3.1) is an index that modifies the metal loss corrosion factor to reflect the impact of water chemistry and pH on the SCC failure rate. The index multiplier associated with each condition state is given by the following:

F_{SCC}	SCC Potential
0.0	no potential
0.1	unlikely potential
0.5	likely potential
1.0	definite potential

The SCC potential condition states and associated indices were selected so that if the environment is not conducive to SCC, then the SCC failure rate will be zero; and if the environment is definitely conducive to SCC, then the failure rate estimate will (depending on other factors) be equal to the metal loss corrosion failure rate. Intermediate index multipliers have been introduced to acknowledge a finite SCC failure potential in the absence of the information necessary to characterize the SCC potential of the environment.

The threshold stress factor, F_{TH}, is an index that modifies the metal loss corrosion factor to reflect the impact of hoop stress level on the SCC failure rate. The hoop stress level is defined in terms of a stress ratio given by

$$StressRatio = \frac{(P - \rho g d)D}{2tS} \qquad [4.13]$$

where: P = line operating pressure (line attribute **Press** in Table 3.1);
D = pipe diameter (line attribute **PipeDia** in Table 3.1);
ρ = sea water density (1024 kg/m^3);
g = gravitational acceleration (9.81 m/s^2);
d = line depth (line attribute **Elev** in Table 3.1);
t = pipe wall thickness (line attribute **PipeWall** in Table 3.1); and
S = pipe body yield stress (line attribute **PipeYield** in Table 3.1).

The index multiplier associated with each condition state is given by the following:

F_{TH}	StressRatio
0.0	< 0.5
0.5	0.5 to < 0.6
1.0	≥ 0.6

The threshold stress condition states and associated indices were selected to acknowledge that the generally recognized threshold for the initiation of SCC is a hoop stress level of between 50 and 60 % of the pipe body yield strength (Beavers and Thompson 1995). For hoop stress levels below 50 % the threshold index multiplier is 0.0 implying that the SCC failure potential is essentially zero. The uncertainty associated with the threshold stress level is reflected by an index multiplier of 0.5 for stress levels in the transition range.

The supplemental cathodic protection factor, F_{CPF}, is an index that modifies the metal loss corrosion factor to reflect the impact of cathodic protection on the SCC failure rate. The index multiplier associated with each value of the cathodic protection level attribute (line attribute **CPlevel** in Table 3.1) is given by the following:

F_{CPF}	Cathodic Protection Level	Characterization
1.0	above average	adequate voltage, uniform level
1.0	average	adequate average voltage, some variability
1.0	below average	inadequate voltage and/or high variability
0.0	no cathodic protection	———

The supplemental cathodic protection factor serves to acknowledge that SCC growth does not occur outside a finite voltage potential range that will not occur naturally on a line without cathodic protection (Beavers and Thompson 1995).

4.2.4.7 Mechanically Induced Crack-Like Defects (girth weld fatigue)

At the current stage of program development, pipeline failure associated with mechanically induced crack-like defects is restricted to the consideration of girth weld fatigue cracks only. Girth weld fatigue tends to occur in susceptible welds (*i.e.*, welds with significant starter defects) that are also undergoing significant stress fluctuations. The factors that are thought to affect the susceptibility of a pipeline to girth weld fatigue are primarily girth weld type, effective stress range and number of stress cycles. Failures due to girth weld fatigue are considered highly line specific and therefore, probability estimation based on historical incident rates adjusted by selected line attributes is not considered appropriate. Alternatively, an approach based entirely on location specific information is employed.

Probability Estimation

The failure rate modification factor developed to reflect the impact of significant factors on the rate of girth weld failure is

$$AF = N_{GW} P_{GWF} \qquad [4.14]$$

where: P_{GWF} = probability of girth weld fatigue failure; and
N_{GW} = effective number of free spans per unit line length.

Note that for the reasons stated above, this parameter will be multiplied by a fixed baseline failure rate estimate of unity, hence the calculated value of AF represents the estimated failure rate due to girth weld fatigue.

The probability of girth weld fatigue failure P_{GWF} is equal to the probability that the number of load cycles, N_L, will exceed the number of cycles associated with failure at the corresponding stress range, N_R. This can be written as:

$$P_{GWF} = P(N_L > N_R) = P(N_R - N_L < 0) \qquad [4.15]$$

If the number of load cycles is treated as a deterministic quantity, and the uncertainty associated with the fatigue life of the weld is characterized by a log normal probability distribution (Albrecht 1983), then the solution to Equation [4.15] is given by

$$P_{GWF} = P(N_R - N_L < 0) = \Phi\left(\frac{\log(N_L) - \mu_{\log(N_R)}}{\sigma_{\log(N_R)}}\right) \qquad [4.16]$$

where: $log(N_L)$ = the log of the number of applied load cycles;
$\mu_{log(NR)}$ = the mean value of the log of the fatigue life of the weld girth;
$\sigma_{log(NR)}$ = the standard deviation of the log of the fatigue life of the weld girth; and

Φ is the standard normal distribution function.

The cumulative number of longitudinal stress cycles is a specified pipeline characteristic (see line attribute **StressCycle** in Table 3.1).

The fatigue life of a weldment, N_R, is typically expressed by a relationship of the form

$$\log(N_R) = b - m \ \log(S_r) \qquad [4.17]$$

where b and m are random variables that can be estimated from regression analysis of fatigue test results, and S_r (line attribute **StressRange** in Table 3.1) is the effective stress range perpendicular to the weldment axis.

Based on this model, and assuming that a typical line pipe girth weld corresponds to an AASHTO weldment category C, it can be shown (see for example, Albrecht 1983) that the fatigue life of the weld is characterized by

$$\mu_{\log(N_R)} = \mu_b - \mu_m \log(S_r) \tag{4.18a}$$

where: μ_b = the mean value of b = 12.68;
μ_m = the mean value of m = 3.097;

and

$$\sigma_{\log(N_R)} = \text{a constant}_{j} = 0.158. \tag{4.18b}$$

The probability of fatigue failure for a typical girth weld can therefore be estimated from Equation [4.16] using the load resistance parameters given in Equations [4.18].

To account for the detrimental effect of poor girth weld quality on fatigue strength, it is suggested that the actual stress range S_r be replaced by an effective stress range S_r^* given by

$$S_r^* = \frac{S_r}{F_{GT}} \tag{4.19}$$

where F_{GT} is a girth weld factor that reflects the reduction in fatigue life caused by the increased size of starter defects associated with problematic welding processes.

The girth weld factor F_{GT} associated with each value of girth weld type (line attribute **JointType** in Table 3.1) is given by the following:

F_{GT}	Joint Type
1.0	High quality weld
0.8	Average quality weld
0.6	Poor quality weld
0.6	Mechanical joint

The girth weld factor range (1.0 to 0.6) is inferred from the CSA pipeline code clause dealing with the effect of longitudinal seam weld type on allowable operating pressure (clause 4.3.3.4, CSA Z662-94). An intermediate or average quality weld category has been introduced to acknowledge the lower level of quality control associated with field-made girth welds (as compared to seam welds). The corresponding girth weld factor has been set half way between CSA range values. The mechanical joint category is assigned the same factor as poor quality welds on the assumption that both are potentially associated with significant flaw or geometry induced stress risers.

Finally, to account for the fact that the model developed above considers only a single weldment, a multiplier is required to convert the probability of failure per susceptible girth weld into a probability of failure per unit line length (see Equation [4.14]). Assuming that stress fluctuations are associated with an unsupported length of pipe (*i.e.*, a free span), and assuming further that each free span will subject only one girth weld to the specified stress range, then the multiplier, N_{GW}, can be approximated by the number of free spans per kilometer for the line section in question (line attribute **NSpan** in Table 3.1).

4.2.4.8 Other Causes

The 'other' causes category is included in the prioritization model to reflect the background failure rate associated with causes that are not typically addressed by maintenance programs intended to maintain the integrity of aging pipelines. The failure rate modification factor for this category is not the result of a single failure mechanism. Therefore, it cannot be based on any single physical model. Instead failure rate data for pipelines in the Gulf of Mexico (MMS 1996) were used to derive empirical relationships between the failure rate and key segment attributes. It was found that the failure rate for 'other' causes is inversely proportional to pipe diameter and does not show any identifiable trend with respect to line age. The failure rate modification factor for failure by 'other' causes is therefore given by

$$AF = \frac{K_{OT}}{D} \qquad [4.20]$$

The expression for K_{OT} is obtained by first rearranging Equation [4.20] and setting AF = 1.0 to give

$$K_{OT} = D \qquad [4.21]$$

Based on a review of the Gulf of Mexico pipeline failure rate data the following reference pipe diameter is suggested as the default value for the 'other' causes reference segment:

- pipe diameter, **PipeDia** = 343 mm.

The corresponding model scale factor is $K_{OT} = 3.43 \times 10^2$.

Tables

Failure Cause	Baseline Failure Rate (incidents/km yr)		Mode Factor		
	Gas Pipeline	Liquid Pipeline	small leak	large leak	rupture
External Metal Loss Corrosion	1.0×10^{-4}	2.6×10^{-4}	0.85	0.10	0.05
Internal Metal Loss corrosion	4.4×10^{-4}	5.4×10^{-4}	0.85	0.10	0.05
Mechanical Damage	1.5×10^{-4}	4.6×10^{-4}	0.25	0.50	0.25
Natural Hazard Damage	0.8×10^{-4}	3.0×10^{-4}	0.25	0.50	0.25
Ground Movement	not applicable	not applicable	0.20	0.40	0.40
Environmental Cracks (SCC)	not applicable	not applicable	0.60	0.30	0.1
Mechanical Cracks (fatigue)	not applicable	not applicable	0.6	0.3	0.1
Other Causes	1.6×10^{-4}	2.8×10^{-4}	0.8	0.1	0.1

Table 4.1 Reference baseline failure rates and relative failure mode factors for offshore pipelines

Coating Type	Soil Corrosivity																				Coating Condition
	High				Above Average				Average				Below Average				Low				
None	264.00	158.40	52.80	26.40	184.00	110.40	36.80	18.40	80.00	48.00	16.00	8.00	53.60	32.16	10.72	5.36	26.40	15.84	5.28	2.64	Below Avg.
	132.00	79.20	26.40	13.20	92.00	55.20	18.40	9.20	40.00	24.00	8.00	4.00	26.80	16.08	5.36	2.68	13.20	7.92	2.64	1.32	Average
	66.00	39.60	13.20	6.60	46.00	27.60	9.20	4.60	20.00	12.00	4.00	2.00	13.40	8.04	2.68	1.34	6.60	3.96	1.32	0.66	Above Avg.
Tape	132.00	79.20	26.40	13.20	92.00	55.20	18.40	9.20	40.00	24.00	8.00	4.00	26.80	16.08	5.36	2.68	13.20	7.92	2.64	1.32	Below Avg.
	66.00	39.60	13.20	6.60	46.00	27.60	9.20	4.60	20.00	12.00	4.00	2.00	13.40	8.04	2.68	1.34	6.60	3.96	1.32	0.66	Average
	33.00	19.80	6.60	3.30	23.00	13.80	4.60	2.30	10.00	6.00	2.00	1.00	6.70	4.02	1.34	0.67	3.30	1.98	0.66	0.33	Above Avg.
Asphalt	66.00	39.60	13.20	6.60	46.00	27.60	9.20	4.60	20.00	12.00	4.00	2.00	13.40	8.04	2.68	1.34	6.60	3.96	1.32	0.66	Below Avg.
	33.00	19.80	6.60	3.30	23.00	13.80	4.60	2.30	10.00	6.00	2.00	1.00	6.70	4.02	1.34	0.67	3.30	1.98	0.66	0.33	Average
	16.50	9.90	3.30	1.65	11.50	6.90	2.30	1.15	5.00	3.00	1.00	0.50	3.35	2.01	0.67	0.34	1.65	0.99	0.33	0.17	Above Avg.
Coal Tar	33.00	19.80	6.60	3.30	23.00	13.80	4.60	2.30	10.00	6.00	2.00	1.00	6.70	4.02	1.34	0.67	3.30	1.98	0.66	0.33	Below Avg.
	16.50	9.90	3.30	1.65	11.50	6.90	2.30	1.15	5.00	3.00	**1.00**	0.50	3.35	2.01	0.67	0.34	1.65	0.99	0.33	0.17	Average
	8.25	4.95	1.65	0.83	5.75	3.45	1.15	0.58	2.50	1.50	0.50	0.25	1.68	1.01	0.34	0.17	0.83	0.50	0.17	0.08	Above Avg.
Poly / Epoxy	16.50	9.90	3.30	1.65	11.50	6.90	2.30	1.15	5.00	3.00	1.00	0.50	3.35	2.01	0.67	0.34	1.65	0.99	0.33	0.17	Below Avg.
	8.25	4.95	1.65	0.83	5.75	3.45	1.15	0.58	2.50	1.50	0.50	0.25	1.68	1.01	0.34	0.17	0.83	0.50	0.17	0.08	Average
	4.13	2.48	0.83	0.41	2.88	1.73	0.58	0.29	1.25	0.75	0.25	0.13	0.84	0.50	0.17	0.08	0.41	0.25	0.08	0.04	Above Avg.
	None	Below Avg.	Avg.	Above Avg.	None	Below Avg.	Avg.	Above Avg.	None	Below Avg.	Avg.	Above Avg.	None	Below Avg.	Avg.	Above Avg.	None	Below Avg.	Avg.	Above Avg.	
	Cathodic Protection Level																				

Note: attribute states corresponding to greyed cells are generally not applicable

Table 4.2 Relative failure rate multipliers for external corrosion incidents on offshore pipelines

Water Depth Range	Platform Zone	Vessel Trafic Density								Depth of Cover
		High		Moderate		Low		No Significant		
Shallow (< 10 m)	100	1000	100	100	10	10	1	1	0.1	None
	50	500	50	50	5	5	0.5	0.5	0.05	Partial
	20	200	20	20	2	2	0.2	0.2	0.02	Complete
Deep (10 to < 60 m)	20	200	20	20	2	2	0.2	0.2	0.02	None
	10	100	10	10	**1**	**1**	0.1	0.1	0.01	Partial
	4	40	4	4	0.4	0.4	0.04	0.04	0.004	Complete
Deep (60 to < 300 m)	4	40	4	4	0.4	0.4	0.04	0.04	0.004	None
	2	20	2	2	0.2	0.2	0.02	0.02	0.002	Partial
	0.8	8	0.8	0.8	0.08	0.08	0.008	0.008	0.0008	Complete
Ultra-Deep (> 300m)	1	10	1	1	0.1	0.1	0.01	0.01	0.001	None
	0.5	5	0.5	0.5	0.05	0.05	0.005	0.005	0.0005	Partial
	0.2	2	0.2	0.2	0.02	0.02	0.002	0.002	0.0002	Complete
		Yes	No	Yes	No	Yes	No	Yes	No	
		Significant Subsea Activity (designated fishing or anchoring zone)								

Note: attribute states corresponding to greyed cells are generally not applicable

Table 4.3 Relative failure rate multipliers for mechanical damage incidents on offshore pipelines

5.0 CONSEQUENCE EVALUATION

5.1 Introduction

An estimate is required of the consequences of line failure for each section within each analysis segment as a function of the mode of line failure. The consequences are calculated for each failure mode using analytical models that have been developed to evaluate product release, movement and decay characteristics, and hazard impact areas and use this information to calculate quantitative measures of the life safety impact, the environmental impact, and the financial impact of line failure. The three distinct consequence components are then combined into a single measure of the loss potential associated with each failure scenario.

Consequence evaluation and combination is carried out for each analysis segment using algorithms that have already been developed and implemented within the framework of an influence diagram that was designed for decision analysis; for further details refer to PIRAMID Technical Reference Manual No. 5.1 (Stephens *et al.* 1996). The influence diagram that forms the basis for the consequence evaluation model used for system prioritization is a modified and somewhat simplified version of the offshore pipeline influence diagram described in the report referenced above.

The simplified consequence evaluation influence diagram used for prioritization is shown in Figure 5.1. This influence diagram can be solved to obtain estimates of the three main consequence measures: *Number of Fatalities*, *Equivalent Residual Spill Volume* and *Total Cost*; as well as the combined consequence measure, referred to herein as *Loss*, as a function of *Failure Mode* (*i.e.*, small leak, large leak, and rupture) and *Failure Section* (*i.e.*, attribute consistent sections along the length of each line segment). Note, a detailed discussion of the steps involved in specifying and solving an influence diagram is given in PIRAMID Technical Reference Manual No. 2.1 (Nessim and Hong 1995).

The following section of this report contains a technical description of the node parameters associated with the consequence evaluation influence diagram shown in Figure 5.1 that differ from those in the decision analysis influence diagram developed previously. The reader is directed to PIRAMID Technical Reference Manual No. 5.1 for a technical description of all other 'common' node parameters.

5.2 Consequence Evaluation Influence Diagram Node Parameters

5.2.1 Failure Mode

The *Failure Mode* node is a modified version of the *Pipe Performance* node in the original decision influence diagram (see Technical Reference Manual No. 5.1). The name change reflects the fact that the four valid states associated with the original node parameter (*i.e.*, safe, small leak, large leak, and rupture) have been revised down to three with the safe state being eliminated. This reflects the fact that the consequences of the safe state (*i.e.*, no failure) are not relevant to the prioritization model and consequences associated with the no failure state (*i.e.*, the *Maintenance Cost* node) have therefore been eliminated.

5.2.2 Impact Location

The *Impact Location* node in the original decision influence diagram (see Technical Reference Manual No. 5.1) has been modified such that the required segment specific node parameter input data (*i.e.*, the arrays of spill impact probabilities for coastal resources, defined by launch zone and season) are obtained directly from the data structure generated at the System Definition stage of model specification (see line attribute **ImpactLoc** in Table 3.1).

5.2.3 Impact Time

The *Impact Time* node in the original decision influence diagram (see Technical Reference Manual No. 5.1) has been modified such that the required segment specific node parameter input data (*i.e.*, the probability distributions for the time to spill impact with coastal resources, defined by launch zone and season) are obtained directly from the data structure generated at the System Definition stage of model specification (see line attribute **ImpactTime** in Table 3.1).

5.2.4 Equivalent Volume

The *Equivalent Volume* node in the original decision influence diagram (see Technical Reference Manual No. 5.1) has been modified such that the required node parameter input data (*i.e.*, the reference spill product and the reference shoreline type) are specified by global model default values.

5.2.5 Interruption Cost

The *Interruption Cost* node in the original decision influence diagram (see Technical Reference Manual No. 5.1) has been modified to calculate unit product transport costs, μ_{trans}, from the following relationship

$$\mu_{trans} = \mu^*_{trans} T_{dist} \qquad [5.1]$$

where μ^*_{trans} is the unit transport cost in dollars per unit volume per unit distance, and T_{dist} is the transport distance associated with products passing through the line segment in question. This calculation approach allows for the definition of universal unit transport cost estimates, by product type, that are independent of segment length and therefore globally applicable to the pipeline system as a whole. The unit cost estimates, μ^*_{trans}, can therefore be specified by global model default values. The required segment specific data, T_{dist}, is obtained directly from the data structure generated at the System Definition stage of model specification (see line attribute **TransDist** in Table 3.1).

In addition, the node has been modified such that the remaining segment specific node parameter input data (*i.e.*, the tendered volume vs. line capacity and the billing abatement threshold) are also obtained directly from the data structure generated at the System Definition stage of model specification (see line attributes **CapFraction** and **BAT** in Table 3.1).

5.2.6 Loss

5.2.6.1 Node Parameter

The *Loss* node is a new node that serves to convert the *number of fatalities* estimate and the *equivalent residual spill volume* estimate into equivalent dollars and to then add these quantities to the *total cost* estimate to produce a combined measure of the total loss associated with line failure in so-called equivalent dollar units. This conversion is carried out based on the so-called 'willingness to pay' concept which involves making an estimate of the amount of money that the pipeline operator, or society as a whole, would be willing to pay to avoid a particular adverse outcome. Using this approach, the cost equivalent of a human fatality can estimated by determining the amount of money that the operator (or society) would be willing to pay to avoid the loss of a statistical life. Similarly, an estimate can be made of the amount of money that the operator (or society) would be willing to pay to avoid the long-term environmental damage associated with the spill of a reference volume of a specific product at a specific reference location.

The algorithm employed to calculate the node parameter which is total loss estimate, *Loss*, for each mode of failure *k* on each section *j* along each segment *i* is given by:

$$Loss_{ijk} = \bar{c}_{ijk} + \alpha_n \bar{n}_{ijk} + \alpha_v \bar{v}_{ijk} \qquad [5.2]$$

where: $\bar{c}$ = mean value of the *total cost*;

$\bar{n}$ = mean value of the *number of fatalities*;

$\bar{v}$ = mean value of the *equivalent volume*;

α_n = equivalent cost of one human fatality; and

α_v = equivalent cost of a unit residual spill volume of reference product at the reference spill location.

5.2.6.2 Equivalent Costs

As indicated previously, the equivalent cost of human fatalities and equivalent spill volumes can be estimated using the willingness to pay (WTP) approach. As developed in the economics literature, and summarized by Rusin and Savvides-Gellerson (1987), the WTP approach, when applied to the value of human life, takes into account an individual's desire to improve their probability of survival by estimating what the individual would be willing to pay for a marginal reduction in their probability of death. Specifically, the WTP method measures the value of goods and services that an individual would be willing to forego in order to obtain a reduction in the probability of accidental loss of life. By averaging this measure across all people exposed to a risk, or a potential change in risk, an estimate of the value of a statistical life is obtained.

In the Rusin and Savvides-Gellerson study cited above, a review of economic studies undertaken by various government agencies and consulting firms led the authors to adopt an estimate of \$2 million dollars as "the value of reducing the risk of death by an amount such that we <u>expect</u> one less death at the reduced risk level". This monetary value is suggested here as a default estimate of the equivalent cost of one human fatality in the absence of a formal evaluation of this cost by the user of the prioritization method.

Similarly, the WTP approach can be applied to equivalent spill volumes wherein an estimate can be obtained of the value of goods and services that an individual would be willing to forego in order to obtain a reduction (or to prevent an increase) in the probability of long-term environmental damage resulting from a unit volume of reference product spilled at a reference location. Given the implicit variability in the actual and perceived impact of different spill products on different environments, it is difficult to come up with a broadly applicable estimate of the equivalent cost (in \$/m^3) of an equivalent spill volume; this quantity is highly operator and location specific.

To provide a point of reference for environmental damage cost equivalents, consider the following. A hypothetical environmental damage assessment case presented by Desvousges *et al.* (1989) indicates an equivalent cost in the range of \$20,000/m^3 to \$200,000/m^3 for a diesel oil spill (with a residual spill volume of approximately 100 m^3) in an environmentally sensitive recreational area. Note that the low end of the cited cost range considers site restoration costs only, whereas the high end of the range reflects the additional loss-of-use value and the so-called non-use value of the damaged resources to people far removed from the spill site who would be willing to pay to simply know that the environmental resource exists and that it is available for use if desired.

As another example, the state of Washington has developed a spill damage compensation formula for estimating public resource damages for oils spills into state waters (Geselbracht and Logan 1993). This formula assigns a damage cost that falls within a range of $\$260/m^3$ to $\$13,000/m^3$ (\$1/USgal to \$50/USgal) depending on the product damage potential and resource vulnerability.

Based on the cited examples, an equivalent unit cost for equivalent spill volumes, referenced to an environmentally sensitive spill location, could easily be on the order of thousands or tens-of-thousands of dollars. A monetary value of \$10,000 is suggested here as a default estimate of the equivalent cost of a cubic metre of equivalent spill volume (referenced to an environmentally sensitive location) in the absence of a formal evaluation of this cost by the user of the prioritization method.

Figures

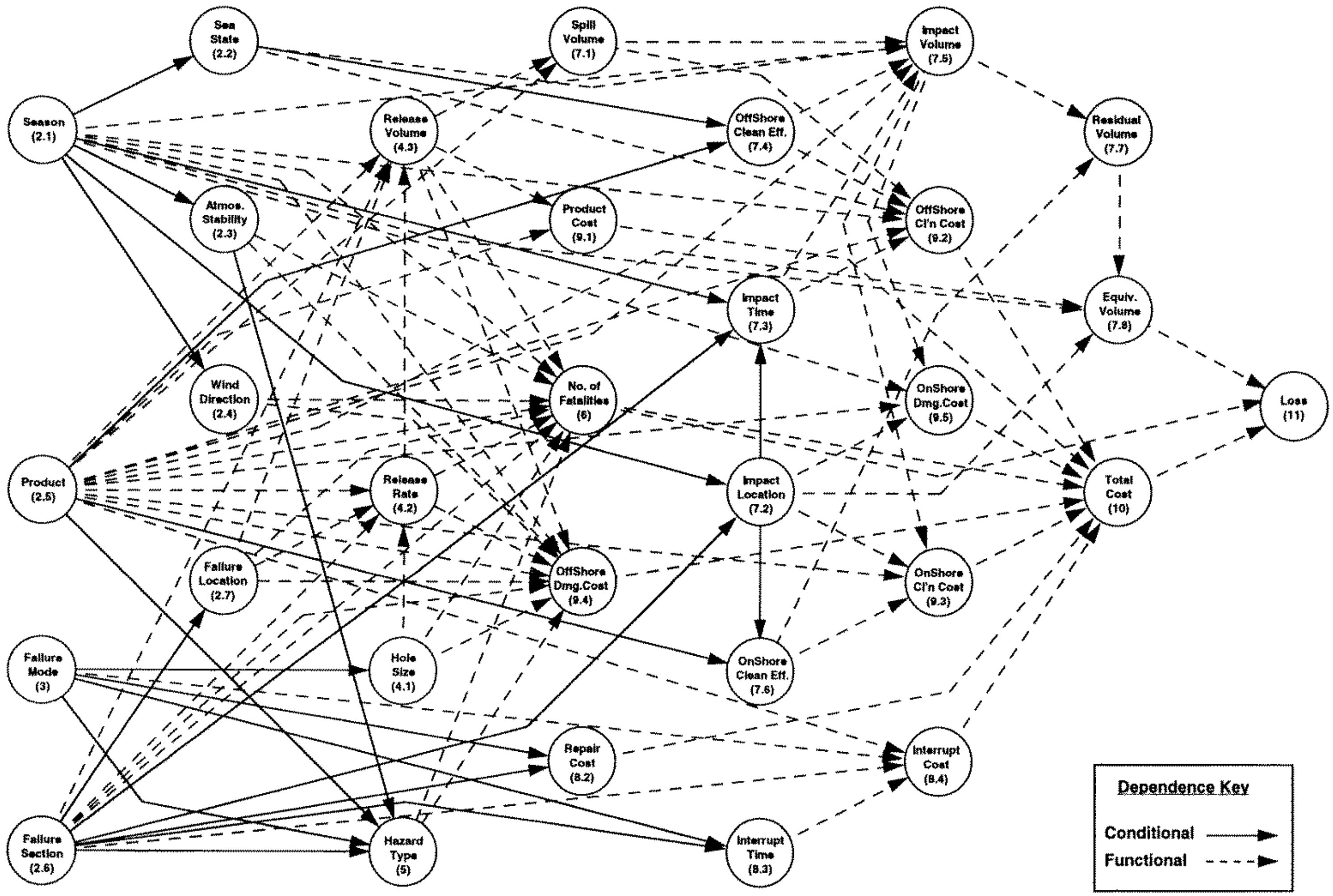

Figure 5.1 Basic node influence diagram for consequence evaluation

6.0 RISK ESTIMATION AND SEGMENT RANKING

6.1 Introduction

Multiplication of the segment-specific failure probability estimate for a given failure cause by the associated combined loss estimate produces an estimate of operating risk defined as the expected annual loss, *ExpLoss*, associated with a given segment of pipeline for the failure cause in question. Summation of the risk estimates for all failure causes associated with a given segment gives an estimate of the total expected annual loss associated with segment operation. Dividing these segment risk estimates by the corresponding segment length yields normalized risk estimates, *ExpLoss**, that allow comparison of calculated risks between segments of different lengths. These cause-specific and combined-cause risk estimates form the basis for a quantitative ranking of all segments identified within a given pipeline system.

6.2 Risk Calculation Model

The expected annual loss *ExpLoss* associated with each failure cause l for each analysis segment i, is given by:

$$ExpLoss_{il} = \sum_{j=1}^{Ns_i} \sum_{k=1}^{Nm} ExpLoss_{ijkl} \quad (\$ / \text{year}) \qquad [6.1]$$

where: $ExpLoss_{ijkl} = Pf_{ijkl}\, Loss_{ijk}$;

Pf_{ijkl} = probability of failure for section j of segment i associated with failure mode k and failure cause l (failures / year);

$Loss_{ijk}$ = combined loss associated with failure on section j of segment i resulting from failure mode k (\$ / failure);

Ns_i = number of sections in segment I; and

Nm = number of failure modes = 3.

The expected annual loss associated with each analysis segment for all failure causes combined is calculated from the following:

$$ExpLoss_i = \sum_{l=1}^{Nc} ExpLoss_{il} \quad (\$ / \text{year}) \qquad [6.2]$$

where: Nc = number of failure causes = 7.

The expected annual loss on a per km basis, $ExpLoss^*$, is be calculated from the per segment quantities, $ExpLoss$, as follows:

on a cause-by-cause basis

$$ExpLoss^*_{il} = \frac{ExpLoss_{il}}{Lseg_i} \quad (\$ / \text{km} \bullet \text{year}) \qquad [6.3]$$

and for the all causes combined case

$$ExpLoss^*_i = \frac{ExpLoss_i}{Lseg_i} \quad (\$ / \text{km} \bullet \text{year}) \qquad [6.4]$$

where: $Lseg_i$ = length of Segment i (km).

6.3 Risk Ranking Model

The probability weighted or expected loss estimates, calculated as described in the previous section, form the basis for the ranking of all specified segments. The basic intention is to rank each segment by failure cause to target high risk segments and associated failure causes for subsequent maintenance decision analysis. The option also exists to rank segments on a combined cause basis which will provide a global measure of risk exposure for each segment. The form of the risk ranking output generated by the prioritization model is illustrated in Figure 6.1.

Figures

Segment Risk Ranking

System: *Western Gulf* **Date:** *11/23/1996*

Failure Causes Considered:

External Corrosion	**Mechanical Damage**	**Ground Movement**	**Girth Weld Fatigue**
Internal Corrosion	**Natural Hazard Damage**	**Stress Corrosion Cracking**	**Other**
All Causes Combined			

Risk Ranking	Segment Designation	Failure Cause	Expected Cost ($/km*yr)	Expected Cost ($/seg*yr)
1	*Loop 13*	*External Corrosion*	*9,999*	*199,000*
2	*Loop 13*	*Ground Movement*	*8,678*	*180,000*
3	*Loop 8*	*Ground Movement*	*8,000*	*80,000*
4	*Loop 12*	*External Corrosion*	*6,699*	*120,000*
5	*Loop 1*	*External Corrosion*	*5,010*	*225,888*
6	*Loop 2*	*External Corrosion*	*5,000*	*120,000*
7	*Loop 2*	*Mechanical Damage*	*4,400*	*100,999*
8	*Loop 3*	*Mechancial Damage*	*4,333*	*43,330*
9	*Loop 13*	*Mechanical Damage*	*3,322*	*74,900*
10	*Loop 12*	*Internal Corrosion*	*3,009*	*62,000*

Figure 6.1 Output format for segment risk ranking

7.0 SUMMARY

The system prioritization stage is intended to identify segments within a pipeline system that may present an unacceptable level of operating risk. To this end pipeline characteristics (or attributes) are evaluated to produce a line-specific estimate of the failure rate for each segment within the system as a function of failure cause (*e.g.*, metal loss corrosion; mechanical damage; ground movement; crack-like defects), and an estimate is made of the potential consequences of segment failure in terms of three distinct consequence components (*i.e.*, life safety, environmental damage, and economic impact). Cause-specific failure rates are then combined with a global measure of the loss potential associated with the different consequence components to produce a single measure of operating risk for all failure causes associated with each segment. Segments are then ranked according to the estimated level of risk, the intention being to identify (or target) potentially high risk segments for subsequent detailed decision analysis at the maintenance optimization stage of the pipeline maintenance planning process.

In the context of the prioritization model developed herein, the components of operating risk are estimated as follows:

The probability of line failure is given by

$$Pf_{ijkl} = Rf_{ijkl} L\sec_{ij} \quad \text{(per year)} \qquad [4.1]$$

where: Rf_{ijkl} = the failure rate associated with section j of segment i for failure mode k and failure cause l; and

$Lsec_{ij}$ = the length of section j within segment i (km).

The segment specific failure rate is given by

$$Rf_{ijkl} = Rfb_l MF_{kl} AF_{ijl} \quad \text{(per km•year)} \qquad [4.2]$$

where: Rfb_l = the baseline failure rate for failure mode l (per km•year);

MF_{kl} = the relative probability or mode factor for failure mode k associated with cause l; and

AF_{ijl} = the failure rate modification factor for section j of segment i associated with failure cause l.

A combined measure of the consequences of line failure is given by

$$Loss_{ijk} = \overline{c}_{ijk} + \alpha_n \overline{n}_{ijk} + \alpha_v \overline{v}_{ijk} \quad \text{(\$ per incident)} \qquad [5.2]$$

where: $\bar{c}$ = mean value of the total cost;

$\bar{n}$ = mean value of the number of fatalities;

$\bar{v}$ = mean value of the equivalent volume;

α_n = equivalent cost of a human fatality; and

α_v = equivalent cost of a unit residual spill volume of reference product at the reference spill location.

The operating risk per segment is given by the probability weighted or expected Loss which on a cause-by-cause basis is given by

$$ExpLoss_{il} = \sum_{j=1}^{Ns_i} \sum_{k=1}^{Nm} ExpLoss_{ijkl} \quad (\$ / \text{year}) \qquad [6.1]$$

where: $ExpLoss_{ijkl} = Pf_{ijkl} \, Loss_{ijk}$

and: Pf_{ijkl} = probability of failure for section j of segment i associated with failure mode k and failure cause l (failures / year);

$Loss_{ijk}$ = combined loss associated with failure on section j of segment i resulting from failure mode k ($ / failure);

Ns_i = number of sections in segment I; and

Nm = number of failure modes = 3.

The normalized operating risk, expressed on a per unit length basis is given by

$$ExpLoss^*_{il} = \frac{ExpLoss_{il}}{Lseg_i} \quad (\$ / \text{km}\bullet\text{year}) \qquad [6.3]$$

where: $Lsec_{ij}$ = the length of segment i (km)

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