221 @ AC

C-FER
200
Karl Clark Road
Edmonton, Alberta
T6N 1E2

Tel: (403) 450-3300
Fax: (403) 450-3700

Final Report

#A AC

Risk-Based Optimization of Pipeline Integrity Maintenance Activities: Project 1 - Methodology

Confidential to
C-FER's Pipeline Program
Participants

Prepared by
Mark Stephens, M. Sc., P. Eng.
Maher Nessim, Ph. D., P. Eng.
and
Qishi Chen, Ph. D., P. Eng.

Copyright © 1994
Centre for Frontier Engineering Research

December 1994
Project 94006

Partners in research...making a difference

Final Report

Risk-Based Optimization of Pipeline Integrity Maintenance Activities: Project 1 - Methodology

Confidential to
C-FER's Pipeline Program
Participants

Prepared by
Mark Stephens, M. Sc., P. Eng.

PROFESSIONAL ENGINEER
M.J. STEPHENS
ALBERTA

and
Qishi Chen, Ph. D., P. Eng.

PROFESSIONAL ENGINEER OF ALBERTA
QISHI CHEN

Maher Nessim, Ph. D., P. Eng.

PROFESSIONAL ENGINEER
MAHER A. NESSIM
ALBERTA

December 1994

Project 94006

PERMIT TO PRACTICE
CENTRE FOR FRONTIER ENGINEERING RESEARCH
Signature
Date 19/1/95
PERMIT NUMBER: P 4487
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

NOTICE

Restriction on Disclosure

This report describes the methodology and findings of a contract research project carried out by the Centre for Frontier Engineering Research on behalf of the Pipeline Program Participants. All data, analyses and conclusions are proprietary to C-FER. The material contained in this report may not be disclosed or used in whole or in part except in accordance with the terms of the Joint Industry Project Agreement. The report contents may not be reproduced in whole or in part, or be transferred in any form, without also including a complete reference to the source document.

The following companies participated in the Pipeline JIP:

NOVA Corporation of Alberta
Foothills Pipe Lines Ltd.
Interprovincial Pipe Line Company
National Energy Board
Minerals Management Services

TABLE OF CONTENTS

Notice		i
Table of Contents		ii
List of Figures		iv
List of Tables		v
Executive Summary		vi
1.0	**INTRODUCTION**	1
1.1	Overview	1
1.2	Objectives and Scope	2
2.0	**RISK ANALYSIS OF PIPELINES**	3
2.1	Rationale for a Risk-Based Approach	3
2.2	Required Input for Risk Analysis of Buried Pipelines	4
2.2.1	Probability of Failure	4
2.2.1.1	Failure Causes	4
2.2.1.2	Probability Estimation	5
2.2.1.2.1	Statistical Approach to Probability Estimation	6
2.2.1.2.2	Analytical Approach to Probability Estimation	8
2.2.1.2.3	Judgemental Approach to Probability Estimation	11
2.2.2	Consequences of Failure	11
2.2.2.1	Hazard Types	11
2.2.2.2	Consequence Estimation	12
2.2.2.2.1	Life Safety Consequences	12
2.2.2.2.2	Environmental Consequences	13
2.2.2.2.3	Economic Consequences	14
3.0	**DEVELOPMENT OF A RISK-BASED DECISION-MAKING FRAMEWORK**	16
3.1	Review and Assessment of Existing Risk-Based Methodologies	16
3.2	Work Required to Implement Risk-Based Decision-Making for Integrity Maintenance	18
3.3	Basis for the Proposed Risk-Based Decision-Making Method	19
3.3.1	Basic Framework	19
3.3.2	Criteria for Evaluating Choices	21

Table of Contents

3.3.2.1 Utility Theory Approach to Evaluating Choices 21
3.3.2.2 Constrained Cost Optimization Approach to Evaluating Choices 23
3.3.2.3 Preferred Approach to Evaluating Choices 24

4.0 PROPOSED METHODOLOGY FOR RISK-BASED DECISION-MAKING 25

4.1 Overall Framework 25
4.2 Key Components of Framework 27
4.2.1 System Prioritization 27
4.2.2 Decision Analysis 29
4.3 Framework Implementation Requirements 32

5.0 SUMMARY 35

6.0 REFERENCES 37

APPENDICES

Appendix A Summary of Pipeline Integrity Issues A.1
Appendix B Review of Pipeline Incident Data Bases B.1
Appendix C Review of Risk Analysis Approaches in the Pipeline Industry C.1

LIST OF FIGURES

Figure 2.1	Overall approach to the estimation of failure probability due to metal loss corrosion using analytical models.
Figure 2.2	Event trees characterizing the hazards associated with pipeline failures.
Figure 2.3	Consequences of pipeline failure.
Figure 2.4	Factors influencing the level of ground and water contamination.
Figure 2.5	Human exposure pathway for water contamination.
Figure 3.1	Steps in risk-based integrity maintenance optimization.
Figure 3.2	Basic framework for integrity maintenance decision-making using influence diagrams.
Figure 3.3	Illustration of the utility optimization approach.
Figure 3.4	Illustration of the constrained cost optimization approach.
Figure 4.1	Proposed framework for risk-based optimization of pipeline integrity maintenance activities.
Figure 4.2	Flow chart for pipeline system prioritization.
Figure 4.3	Flow chart for integrity maintenance decision analysis.
Figure 4.4	Detailed flow chart outlining pipeline system prioritization program.
Figure 4.5	Conceptual influence diagrams for decision analysis of integrity maintenance strategies.
Figure 4.6	Expanded decision influence diagram for decision analysis of integrity maintenance strategies.
Figure 4.7	Expanded influence diagram for consequence estimation.

LIST OF TABLES

Table 2.1 Summary of relative failure probabilities by cause for natural gas and hazardous liquid pipelines.

Table 2.2 Attributes that effect the failure probability of buried pipelines.

Table 2.3 Damage characterization capability of inspection methods applicable to buried pipelines.

Table 2.4 Parameters associated with pipeline failure prediction models.

Table 2.5 Available maintenance alternatives for buried pipelines.

Executive Summary

The Centre for Frontier Engineering Research (C-FER) is conducting a joint industry research program directed at the optimization of pipeline integrity maintenance activities using a risk-based approach. This report describes the development of a systematic, comprehensive methodology for risk assessment of existing pipeline systems and identifies the data and models needed to implement the methodology in making integrity maintenance decisions. It includes a review of the factors contributing to pipeline risk, a critical assessment of risk analysis approaches currently employed in the industry, and a detailed outline of the proposed methodology.

The two key components in the proposed methodology are: (1) a system prioritization stage that is intended to identify pipelines or pipeline segments within a system that present unacceptable levels of risk and/or to identify segments that would benefit the most from expenditures on risk reduction through integrity maintenance activities; and (2) a decision analysis stage that is intended to assess available integrity maintenance alternatives to determine the optimal set of inspection and maintenance activities for segments targeted at the prioritization stage.

The system prioritization stage is envisioned as a software program that will process segment-specific attributes to provide an estimate of the failure rate for individual segments as a function of failure cause, and 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 prioritization program will then combine the cause-specific failure rates with a global measure of the loss potential associated with the different consequence components into a single measure of risk. Finally, segments will be ranked according to the estimated level of risk and optionally, according to the estimated cost of a unit reduction in total risk (*i.e.* the incremental cost of risk reduction) if appropriate additional user input is provided.

The proposed decision analysis stage involves a software program that implements formal decision analysis theory using influence diagrams and an associated solution algorithm to determine the optimal set of decisions for a given integrity maintenance decision analysis problem by maximizing the value of all possible actions. The program will be structured to define the value associated with integrity maintenance choices in two different ways. The first approach will incorporate a value function based on utility theory, in which case the resulting set of decisions will be an optimal compromise between the different consequences (i.e. the number of fatalities, the extent of environmental damage, and the total financial cost). The second approach will involve a value function that reflects economic consequences only wherein the optimal decision set will be associated with minimum cost, potentially constrained by limits on life safety and/or environmental damage risk, and possibly by maintenance budget limitations.

In addition, the proposed decision analysis program will refine the risk estimate made at the prioritization stage and also calculate the incremental cost of risk reduction associated with the optimal integrity maintenance strategy. This will facilitate a refined ranking of segments by risk level and by incremental cost of risk reduction which can form the basis for prioritizing the implementation of integrity maintenance activities.

1.0 INTRODUCTION

1.1 Overview

The Centre for Frontier Engineering Research (C-FER) is conducting a Joint Industry research Program (JIP) directed at the optimization of pipeline integrity maintenance activities using a risk-based approach. The goal of the JIP is to develop models and software tools for estimating the risk levels associated with individual pipelines or individual segments within a pipeline system. The models and tools developed will allow risk reductions associated with various inspection and maintenance activities to be quantified, providing a basis for comparing alternatives. The overall framework will include an approach to evaluate potential risk reduction benefits against the associated costs, thus allowing optimal decisions to be made regarding the choice of an integrity maintenance strategy.

This program addresses an area of concern for Canadian as well as international pipeline companies. In Canada alone there is in excess of 250,000 km of natural gas, crude oil and petroleum product pipeline. In all of North America, over one-half of the large diameter pipeline system is older than 25 years. Maintaining the integrity of this vast and aging network is an area of prime interest to Canadian and US pipeline companies.

Integrity maintenance decisions have traditionally been based on subjective assessment of pipeline inspection data. More recently, engineering analysis of the data has provided a more rational basis for technical decisions. Risk analysis can transform inspection data into information that is directly related to the operator's objective, namely to reduce the probability of failure of individual segments within a pipeline system in a balanced manner that acknowledges the potential differences in the consequences of failure associated with different line segments.

The potential economic benefits to pipeline operators of using a risk-based approach are significant. On the one hand, any small reduction in failure rates resulting from better maintenance planning, would reduce the potentially high costs of failure. On the other hand, if excessive conservatism in repair strategies can be identified and eliminated, costly premature maintenance activities may be avoided.

1.2 Objectives and Scope

This report describes the results of the first phase of the JIP, the objective of which was to develop a comprehensive methodology for risk assessment of existing natural gas, crude oil and petroleum product pipeline systems (excluding facilities and isolated mechanical components) and to identify the data and models needed to implement the methodology in decision-making as it relates to integrity maintenance activities. The types of decisions to be addressed by the methodology include the choice of inspection methods (*e.g.* right-of-way patrols, coating damage surveys, and in-line inspection) and inspection intervals, as well as the choice of maintenance actions (*e.g.* coating damage repair, sleeve repair, and cut-out replacement).

The report includes a review of the factors affecting the risks associated with pipeline operation, a critical assessment of risk analysis approaches currently employed in the industry, and a discussion of the background to the proposed approach. It then provides a detailed outline of the framework that is proposed for estimating the overall risk associated with individual segments within a pipeline system, for identifying segments that require, or would benefit the most from, risk reduction through integrity maintenance action, and for using quantitative risk estimates to determine the optimal set of inspection and maintenance actions for critical segments.

2.0 RISK ANALYSIS OF PIPELINES

2.1 Rationale for a Risk-Based Approach

Recognition of the uncertainties associated with engineering systems has led to wide application of the concepts of risk and reliability as a basis for analysis and design. In the context of this project, *reliability* is defined as the probability that a segment of line pipe will not leak or rupture in a given period of time. It is equal to the probability of failure subtracted from 1. *Risk* is defined as the probability of line failure multiplied by a measure of the adverse consequences associated with failure (*e.g.* financial cost), should it occur.

The benefits of reliability-based design are well recognized, as evidenced by the number of design codes currently in use world-wide that are based on reliability concepts, and the recent move in Canada to develop a reliability-based (or limit states design) code for pipeline systems. This approach to design achieves consistent safety levels (*i.e.* consistent failure probabilities) by addressing the actual failure modes and taking into account the effects of uncertainty in applied loads and element resistance. The proposed risk-based methodology can be seen as a natural extension of the reliability-based design approach to address operational decisions regarding inspection and maintenance with the added refinement that failure consequences will be evaluated in addition to failure probabilities in the decision-making process.

A risk-based approach that acknowledges uncertainty is particularly relevant to pipeline integrity maintenance activities because of the added uncertainties associated with line condition assessment in general and more specifically with the line inspection process and the models used to assess damage indicated by inspection. A quantitative estimate of overall operating risk that explicitly accounts for these uncertainties will provide an ideal characterization of the effectiveness of different maintenance strategies and a rational basis for comparing these strategies. Furthermore, the risk-based decision analysis results will provide the basis for eliminating unnecessary conservatism, increasing confidence in the decisions made and providing the necessary background information to understand and communicate the rationale behind those decisions.

2.2 Required Input for Risk Analysis of Buried Pipelines

Implementation of a risk-based methodology for pipeline integrity maintenance decision analysis, as envisioned in this project, requires quantitative estimates of both the probability of failure and the consequences associated with line failure. The failure probability for a given pipeline system, or line segment within a system, depends on the causative mechanisms that are active, the damage extent (or damage potential) associated with each active failure cause, and the inspection and maintenance actions that are taken to mitigate the probability of line failure. Failure consequences include a financial cost component and other non-monetary components that describe the impact of potential release hazards on people and the environment in the vicinity of the failure site.

2.2.1 Probability of Failure

2.2.1.1 Failure Causes

Review of historical pipeline incident data and the literature summarizing pipeline failures (in particular Eiber *et al.* 1993) suggests that failure causes can be grouped into four major categories. These include: outside force (including third-party damage and ground movement); environmentally induced defects (including metal loss corrosion and stress corrosion cracking); material and fabrication defects; and other (including operational errors and mechanical component failures). The main categories and significant sub-categories are summarized in Table 2.1 together with estimates of their respective contributions to the total number of pipeline failure incidents (leaks and ruptures) based on recent data summaries compiled by the Energy Resource Conservation Board (ERCB 1991) for pipeline failures occurring in Alberta, and by the American Gas Association (AGA 1992) and Hovey and Farmer (1993) using U. S. Department of Transportation data on natural gas and hazardous liquid pipeline failures, respectively.

The data supports the widely held opinion that outside force (primarily third-party mechanical damage) and metal loss corrosion (primarily external galvanic corrosion) account for a majority of the failures in both petroleum liquid and natural gas gathering and transmission lines. Failures due to ground movement were not found to contribute significantly to the total number of reported incidents but it is noted that integrity concerns associated with active or potential ground movement are of overriding importance at selected locations on existing systems and/or in proposed Arctic systems. Stress corrosion cracking does not yet constitute a major cause of failure but it is expected to develop into a major problem if reliable detection and assessment techniques are not developed.

In general, material and fabrication defects are not considered to be a major concern for existing pipelines because the associated defects generally do not grow with pipeline age and most of the failure critical defects are removed during the initial hydrostatic line test or fail during the first few years of service (Kulkarni and Conroy 1991). However, some crack-like weld zone defects, in particular longitudinally oriented seam weld cracks, have been identified as an area of industry concern because of their propensity to grow and fail under cyclic loading caused by outside forces or internal pressure fluctuations.

Based on the above, the following mechanisms are indicated as potentially significant failure causes for existing buried gas and liquid pipelines:

- third party damage;
- ground movement;
- external metal loss corrosion;
- internal metal loss corrosion;
- stress corrosion cracking (SCC); and
- crack-like weld defects.

2.2.1.2 Probability Estimation

In estimating the failure probability associated with a given failure cause for a specific pipeline, it is important to recognize that the probability depends on the factors contributing to the existing damage extent (or damage potential), the inspection methods currently or soon to be available to detect and quantify the existing damage extent (or damage potential), the damage assessment methods currently employed to estimate the criticality of detected defects, and the maintenance actions available to mitigate the likelihood of failure in the presence of existing (or potential) damage. A review of literature in the field of pipeline integrity was undertaken to develop an understanding of these issues. The findings of this review are summarized, by failure cause, in Appendix A.

The review suggests that the failure probability associated with a given pipeline or pipeline segment can, in principle, be estimated using three different approaches: a statistical approach based on historical failure rate data and characteristic attributes of the pipeline, an analytical approach based on pipeline inspection data and structural reliability theory, and a judgemental approach based on the subjective opinion of experts. The proposed risk-based methodology will accommodate all three approaches.

2.2.1.2.1 Statistical Approach to Probability Estimation

Using the statistical approach, historical line failure data is evaluated to identify correlations between the rate of line failure (i.e. number of failures per unit length per year of operation) and various characteristic attributes of a pipeline. This approach assumes that for each significant failure cause the pipeline can be grouped with other pipelines having similar attributes. The failure rate for the line in question is set equal to the historical failure rate for pipelines with similar characteristic attributes and this rate estimate can be used to calculate a probability of line failure within a given time period.

Characteristic attributes define a pipeline in terms of the potential level of damage exposure and the level of strength reserve. Damage exposure attributes reflect damage potential or damage extent and can be divided into two categories; those that are directly associated with a pipeline damage mechanism (causative attributes) and those that are associated with the protection of a pipeline from a particular damage mechanism (protective attributes). The strength reserve (resistive attributes) reflects the resistance of a pipeline to failure when subject to a particular damage mechanism. Depending of the failure mechanism, some attributes effectively fall into more than one category (e.g. for external metal loss corrosion, coating type can be both causative and protective depending on the type of coating and the soil environment). Representative attribute sets associated with each significant failure cause, as determined on the basis of the literature review summarized in Appendix A, are given in Table 2.2.

The required historical failure rate data (*i.e.* number of failure incidents per kilometre year) is calculated from pipeline failure incident data (*i.e.* number of incidents on a given line or system of lines) and pipeline exposure data (*i.e.* incident reporting time interval multiplied by line or system length). Pipeline failure incident data is compiled on an annual basis by various government regulatory agencies (e.g. the Energy Resources Conservation Board of Alberta, the National Energy Board and the Transportation Safety Board of Canada, and the U. S. Department of Transportation Office of Pipeline Safety) as well as by petroleum and pipeline industry associations (e.g. the Canadian Association of Petroleum Producers, the American Gas Association, the European Gas Pipeline Incident Data Group, and the Oil Companies European Organization for Environmental and Health Protection). Most of the incident data gathering groups provide estimates of the length of the pipeline system associated with the reported incidents from which failure rate estimates can be calculated. Processed historical failure data (*i.e.* failure rate estimates broken down by various broad pipeline attribute categories such as product type, failure cause, and line diameter) is also compiled and published by government agencies (*e.g.* ERCB 1991), industry associations (*e.g.* CAPP 1992, AGA 1992, EGIG 1993, CONCAWE 1993), and private consultants (*e.g.* Hovey and Farmer 1993, Payne *et al.* 1993). A summary of the form and content of major North American and European failure incident data bases and the statistical summary reports referenced above is given in Appendix B.

The feasibility or accuracy of the statistical approach to probability estimation depends on the amount and quality of historical data that is available and the degree to which the available data can be subdivided into attribute combinations that are representative of the pipeline under consideration. The degree to which the data can be subdivided depends on the level of refinement associated with the reporting of characteristic attributes on incident reports. It is noted that with regard to the incident data sources referenced above, the incident reporting criteria (*i.e.* the definition of what constitutes a reportable incident) and the report structure vary considerably (see Appendix B). This suggests that a large and consistent database of failure rates may be difficult to assemble from public domain sources alone. In addition, pipeline failures are relatively rare events and if the inherently limited data set must be subdivided into small groups to obtain the desired attribute combinations, there may not be enough data in each group to provide a reliable estimate of failure probability.

Where the available historical data set is not sufficient to provide a reliable attribute-specific estimate of failure probability, the option exists to use expert judgement to adjust historical probability estimates to account for the likely impact of attributes that are not reflected in the data set. This implies that as the ability to subdivide the historical data set is reduced, the probability estimate based on statistical data becomes increasingly subjective and potentially less accurate. In the limiting case the statistical approach devolves into an entirely judgemental approach (see section 2.2.1.2.3).

2.2.1.2.2 Analytical Approach to Probability Estimation

Using the analytical approach, theoretical and/or empirical failure prediction models are combined with probabilistic analysis to calculate a failure probability for pipeline segments based on the damage extent determined from direct inspection or inferred from previous inspections.

The approach requires a suitable deterministic model that can be used to predict line failure in the presence of a particular damage feature (*e.g.* flaw depth, length, and orientation) for a given set of geometric parameters (*e.g.* diameter and wall thickness), mechanical properties (*e.g.* yield strength and notch toughness), and operating parameters (*e.g.* internal pressure). The uncertainties associated with the failure model itself and with the required input parameters are then quantified and these uncertainties are combined in a probabilistic model to estimate the probability of failure (or reliability) associated with a pipeline segment. This approach to failure probability estimation is illustrated for metal loss corrosion damage in Figure 2.1.

There are different methods available to carry out this type of analysis. Common approaches include First and Second Order Reliability Methods (*i.e.* FORM and SORM) and Monte Carlo simulation (Madsen *et al.* 1986). Using these methods, the probability of failure can be calculated for an individual damage feature or for an entire segment of the pipeline considering the cumulative effect of all damage features.

Implementation of this approach requires a quantitative measure of the damage extent and severity as well as an estimate of the accuracy or uncertainty associated with the measured damage. Inspection methods currently available, or under active development, to detect the location of and/or to measure the severity of damage in buried pipelines can be broadly classified into three categories: ground based methods; in-line methods; and proof testing (*i.e.* hydrostatic pressure testing). Ground based methods include: right-of-way patrols; ground and pipe movement surveys; close interval surveys (*i.e.* coating damage and/or cathodic protection surveys); and targeted excavation programs. In-line inspection methods involve the use of "intelligent pigs" to detect cross-section geometry and/or pipe position and pipe wall defects (*i.e.* metal loss and/or cracks).

These inspection methods are summarized in Table 2.3 together with an indication of the extent to which the various methods are able to locate and measure the different types of damage that are associated with the main causes of failure. Depending on the inspection method and the type of damage, the inspection results can range from a simple indication of possible damage to a highly accurate measurement of damage extent and severity along the entire length of a segment. Note that for all significant failure causes, inspection methods, or combinations of methods, either currently exist or are under active development to provide quantitative measurements of damage extent and severity. The different methods are distinguished by the potential accuracy (*i.e.* level uncertainty) associated with the measurements obtained and by the costs associated with their implementation.

Implementation of the analytical approach to failure probability estimation will require assessment of the level of accuracy (or degree of uncertainty) associated with each of the above inspection methods. It is assumed that inspection measurement uncertainty can be determined from operating company inspection verification data and/or from information supplied by inspection tool vendors.

As indicated, implementation will also require analytical models that predict failure in the presence of defects. These failure prediction models are well developed for defects associated with metal loss corrosion (Chouchaoui and Pick 1994). Models for defects resulting from mechanical damage (*i.e.* dents and gouges within a dent) are also available (Eiber and Bubenik 1993, Jiao *et al.* 1993) although they are less well developed than those for metal loss defects.

Failure prediction models for SCC defects are presently under investigation by various research groups. A model developed for part through-wall, crack-like defects (Kiefner *et al.* 1973) is currently available for SCC defects but the model assumes that only a single crack is present and thereby does not take into account the effects of a network of parallel cracks adjacent to the critical crack which is characteristic of SCC defect sites. This model is, however, well suited to the assessment of crack-like defects in or immediately adjacent to welds.

Models for the assessment of large (*i.e.* inelastic) axial compressive and/or bending strains caused by excessive ground movement are available for compressive strains (*e.g.* Zimmerman *et al.* 1994), however, similar models for large, potentially inelastic tensile strains caused by ground movement are currently an area of active research.

The input parameters associated with the failure prediction models described above are summarized in Table 2.4. The uncertainty associated with the available failure prediction models can be estimated from the experimental data that was used to calibrate the models. The uncertainties associated with the damage independent input parameters (*e.g.* internal pressure, yield strength, wall thickness) can be characterized on the basis of published historical data.

In addition, using the analytical approach, it is assumed that the failure prediction models used to estimate line failure probabilities will also be used to identify failure-critical defects that, at the time of inspection (or in the near future assuming defect growth), are associated with an unacceptably low level of operating safety as defined by various pipeline design and operating codes or by recognized engineering critical assessment procedures. It is further assumed that proactive maintenance action (*e.g.* for critical external corrosion damage: coating damage repair, sleeve repair or cut-out repair) will be undertaken by the operating company to mitigate the likelihood of failure at these critical defect locations which will thereby effectively alter the overall damage extent for the pipeline segment under consideration. Table 2.5 provides a representative listing of the proactive maintenance actions that can potentially be addressed using the proposed analytical approach to failure probability estimation. The list, developed from the review of pipeline integrity issues summarized in Appendix A, includes both preventative actions intended to mitigate potential damage (e.g. future third-party damage) and remedial actions intended to mitigate existing damage (e.g. existing corrosion defects).

Where satisfactory failure prediction models do not exist, or where the uncertainty associated with damage extent measurements or other damage independent parameters cannot be established with confidence on the basis of available data, the option exists to develop approximate models or to subjectively define uncertainty levels that give failure probability estimates that are consistent with historical trends or expert judgement. The extent to which a subjective or judgemental approach to analytical modelling is warranted depends on whether other methods (*e.g.* a statistical approach) are available that will provide a more objective and potentially more accurate estimate of failure probability. If an alternate approach is not clearly indicated it is considered that the incorporation of judgement within the otherwise consistent and rigorous framework of reliability analysis is an ideal way to address information deficiencies.

2.2.1.2.3 Judgemental Approach to Probability Estimation

Where adequate data and/or models are not available to facilitate objective estimation of the probability of failure using a statistical or analytical approach, the only available option is to take a subjective approach where the estimate is based on expert judgement. The accuracy or validity of a judgemental approach depends on the knowledge and experience of the expert adviser and the degree to which estimation reference points (*i.e.* upper and lower bounds on failure rates) can be defined to guide and/or constrain the subjective assessment of failure probability.

2.2.2 Consequences of Failure

2.2.2.1 Hazard Types

The consequences of a pipeline failure event are to an extent dependent upon the type of hazards associated with failure. The potential hazard types associated with the failure (leak or rupture) of either natural gas or hazardous liquid pipelines are summarized in the event trees shown in Figure 2.2. They include fire (jet fire, flash fire or pool fire), explosion (causing overpressure and projectiles), toxic or asphyxiating clouds, and hazardous liquid spills.

The relative probability of occurrence of the different potential hazards depends primarily upon product type and ignition probability. Ignition probability in turn depends on the release characteristics associated with a particular failure (*e.g.* leak vs. rupture), and the number of potential ignition sources as reflected by type of land use at the failure location (*e.g.* rural, industrial, urban). Similarly the hazard zone size, intensity, and duration are dependent upon factors such as product type, the release characteristics associated with a given failure (*e.g.* release rate and release volume), and the prevailing weather conditions at the time of failure (*i.e.* ambient temperature, wind velocity and atmospheric stability class). For liquid spills the extent of contaminated ground and/or water depends on many factors including release volume, season (*i.e.* frozen or unfrozen ground), soil type, terrain conditions, and proximity to water.

2.2.2.2 Consequence Estimation

The consequences associated with failure, and with the different hazards resulting from failure, can be estimated in terms of the number of casualties (life safety consequences), the extent of environmental damage (environmental consequences), and the financial impact on the operating company and society as a whole (economic consequences). The different consequence components and an indication of how they combine and affect one another is illustrated by the flow chart given in Figure 2.3.

2.2.2.2.1 Life Safety Consequences

Fires, explosions, and toxic or asphyxiating clouds resulting from line failure may cause human fatalities or injuries. However, life safety consequences are usually measured in terms of the number of fatalities only. Models have been developed and calibrated against tests to characterize emission, dispersion, vaporization, fire and explosion due to hydrocarbon release (*e.g.* Lees 1980, FEMA 1989). Estimates of the relative probabilities of occurrence of these hazards, as a function of product type and land use, are available (*e.g.* Crossthwaite *et al.* 1988, EGIG 1993). Fatality thresholds associated with thermal radiation, blast overpressure, and toxic or asphyxiating gas/vapour inhalation have also been established (*e.g.* Lees 1980, Crossthwaite *et al.* 1988).

The calculation of the number of fatalities, **N**, associated with a given hazard type and the probable number of fatalities resulting from a given release incident is therefore a relatively well defined process. Proprietary and public domain software programs implementing the required calculation models, to varying degrees of sophistication, are currently available or under development (*e.g.* FEMA 1989, Hopkins *et al.* 1993).

2.2.2.2.2 Environmental Consequences

Environmental consequences are primarily associated with liquid releases involving crude oils and refined petroleum products (*e.g.* gasolines and fuel oils). Residual volumes of the hazardous substances contained in these liquid products can have an impact on human health and the environment due to potential long-term effects associated with exposure to contaminated ground surfaces and water sources.

Modelling of these long-term effects is a complex and uncertain process. For example, Figure 2.4 illustrates some of the parameters that have an impact on the level of ground or water contamination. To assess the long-term effects of ground or water contamination on human health and the environment, an exposure analysis (see for example Figure 2.5) is required to estimate the total received dosage and the potential human health risk or environmental damage extent can then be assessed based on appropriate dose-response relationships for the hazardous substances involved.

The forgoing suggests that a large number of parameters are involved in a quantitative assessment of health risk and/or environmental damage extent. Many of these parameters are highly location specific and potentially difficult to quantify given the current state-of-the-art in environmental impact assessment. Alternatively it is proposed that spill volume can serve as a simple quantitative measure of the overall environmental damage extent or damage potential.

Recognizing, however, that the potential environmental damage extent will be significantly influenced by factors other than just spill volume (*e.g.* spill clean-up efficiency, toxicity of spilled product, and spill site proximity to populated areas), it is considered that a more representative and comprehensive measure of the environmental damage extent would be an effective residual spill volume, V_e, which can be assumed to be a function of the residual spill volume, V_r, defined as the volume of product remaining after clean-up, and a spill impact factor, S_v, that reflects the potential effect of a unit volume of residual spill on long-term human health and the environment.

Residual spill volume (V_r) is dependent on the total spill volume and the potential clean-up efficiency, which in turn depends on factors such as: product type; soil type; topography; proximity to water; and season of occurrence. The spill impact factor (S_V) is, in the context of this approach, a subjective factor that is intended to reflect the impact on human health and the environmental of the following spill attributes: product toxicity; land use and sensitivity of the ecosystem at the spill site; and affected population.

Assessment of the total spill volume can be based on existing product emission models (*e.g.* Lees 1980, FEMA 1989). Assessment of the spill clean-up efficiency and spill impact factor for different combinations of spill attributes will require judgement on the part of experts in the environmental field supported where possible by relevant historical and toxicological data.

2.2.2.2.3 Economic Consequences

The economic consequences of failure are measured by the total financial cost born by the operator, **C**, which is simply the sum of the direct costs associated with line failure and the hazard related costs, all of which can be adjusted to reflect the time value of money which in turn depends on the real or effective interest rate (*i.e.* the stated rate of return on investment minus the rate of inflation) and the time to failure (see Figure 2.3).

The direct cost components include:

- the cost of line repair;
- the cost of lost product; and
- the cost associated with service interruption.

Hazard related costs include:

- the cost of property damage;
- the cost of spill clean-up and site restoration;
- the cost of compensation for deaths and injuries;
- the cost of compensation for environmental damage related to:
  - loss of wildlife and/or damage to habitat,
  - loss or damage to natural and/or recreational resources,
  - economic dislocation, and
  - sociological and cultural disruption;

- legal and consulting fees; and
- fines.

The hazard related costs associated with property damage and death or injury can be determined from: (1) estimates of the damage extent and/or number of casualties based on the same hazard characterization models that are required for life safety consequence assessment (except that building damage thresholds for thermal radiation and overpressure are substituted for the human fatality thresholds in the property damage assessment); and (2) historical data on property replacement values as a function of land use and on the level of compensation paid for loss of life or injury.

Spill clean-up costs will depend on the spill volume and the unit clean-up cost which in turn depends on product type, season of occurrence, spill character (*i.e.* ground or water born), site accessibility, and clean-up method. The clean-up method employed (*i.e.* physical removal, bio-remediation, chemical cleaning, or water washing) and the associated cost will be dependent upon the physical characteristics of the spill site and the required degree of clean-up (*i.e.* ecological sensitivity of the site).

The costs associated with environmental damage compensation will depend on the level and extent of site contamination and a measure of the potential long-term impact of contamination on the spill site, both of which are reflected in the effective residual spill volume. It will be necessary to make use of historical data to estimate appropriate levels of compensation as a function of product type and spill site attributes.

Figures and Tables

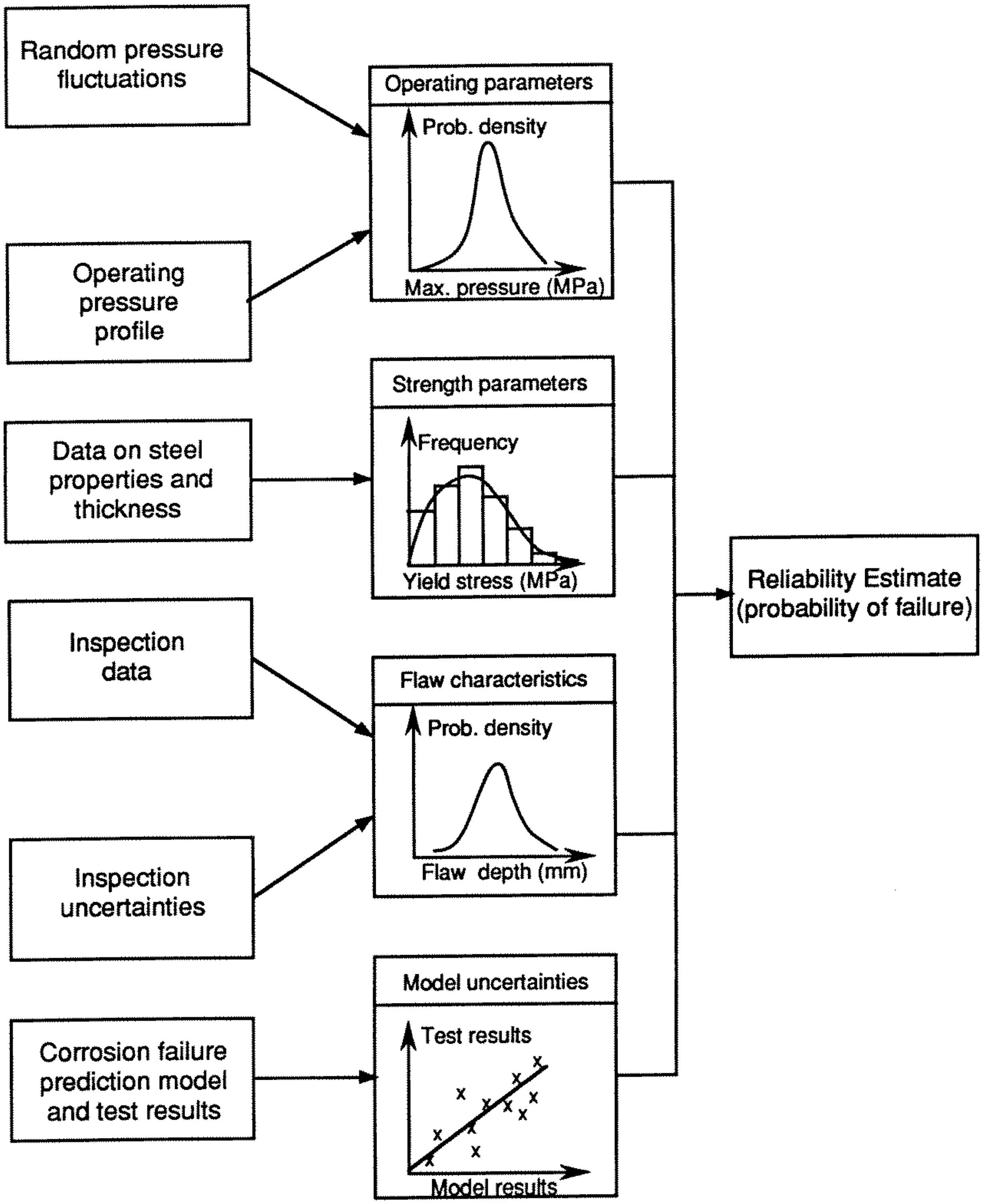
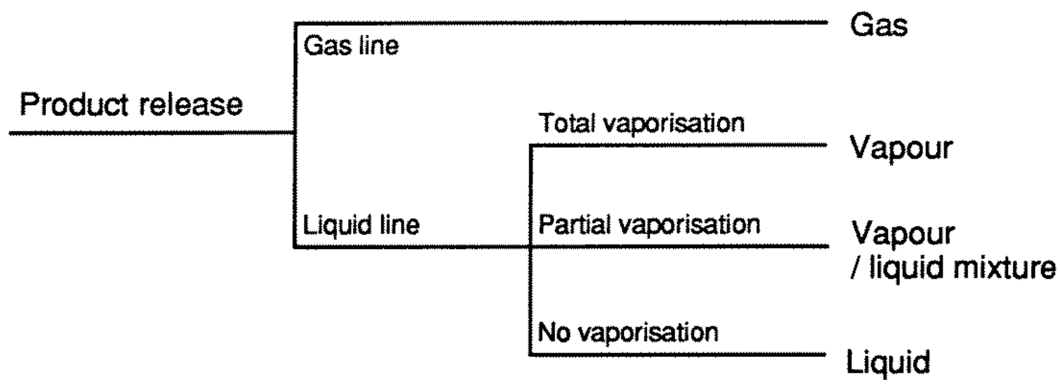
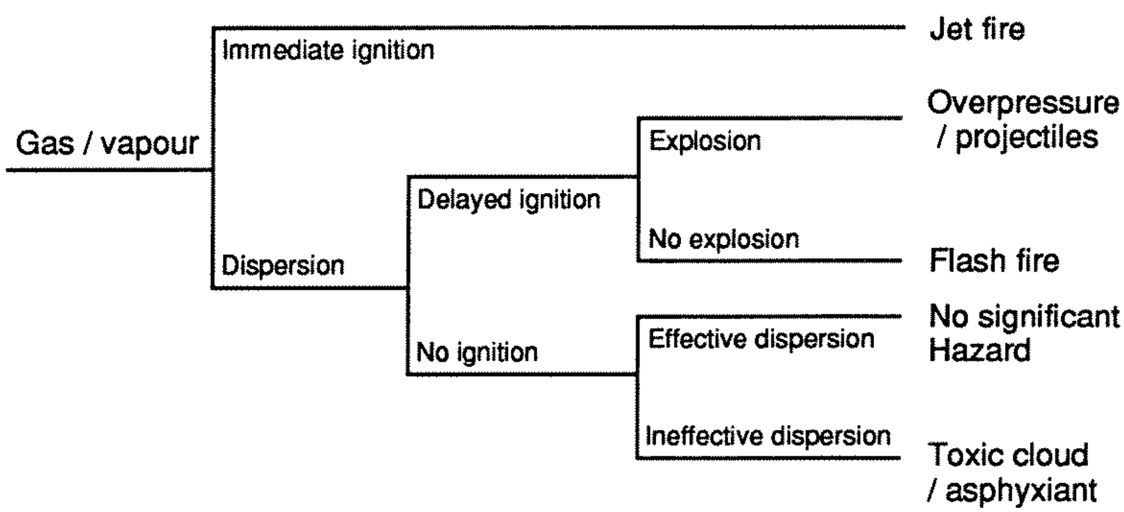


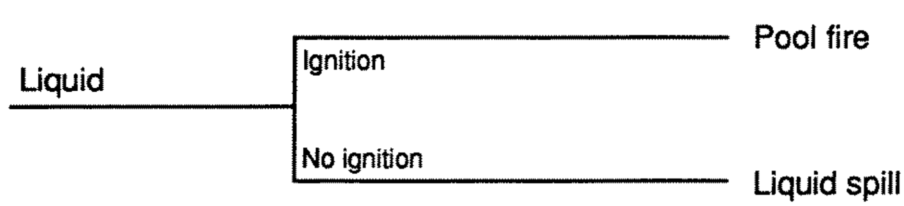
Figure 2.1 Overall approach to the estimation of failure probability due to metal loss corrosion using analytical models.



(a) Release of product



(b) Hazards associated with gas / vapour release



(c) Hazards associated with liquid release

Figure 2.2 Event trees characterizing the hazards associated with pipeline failures.

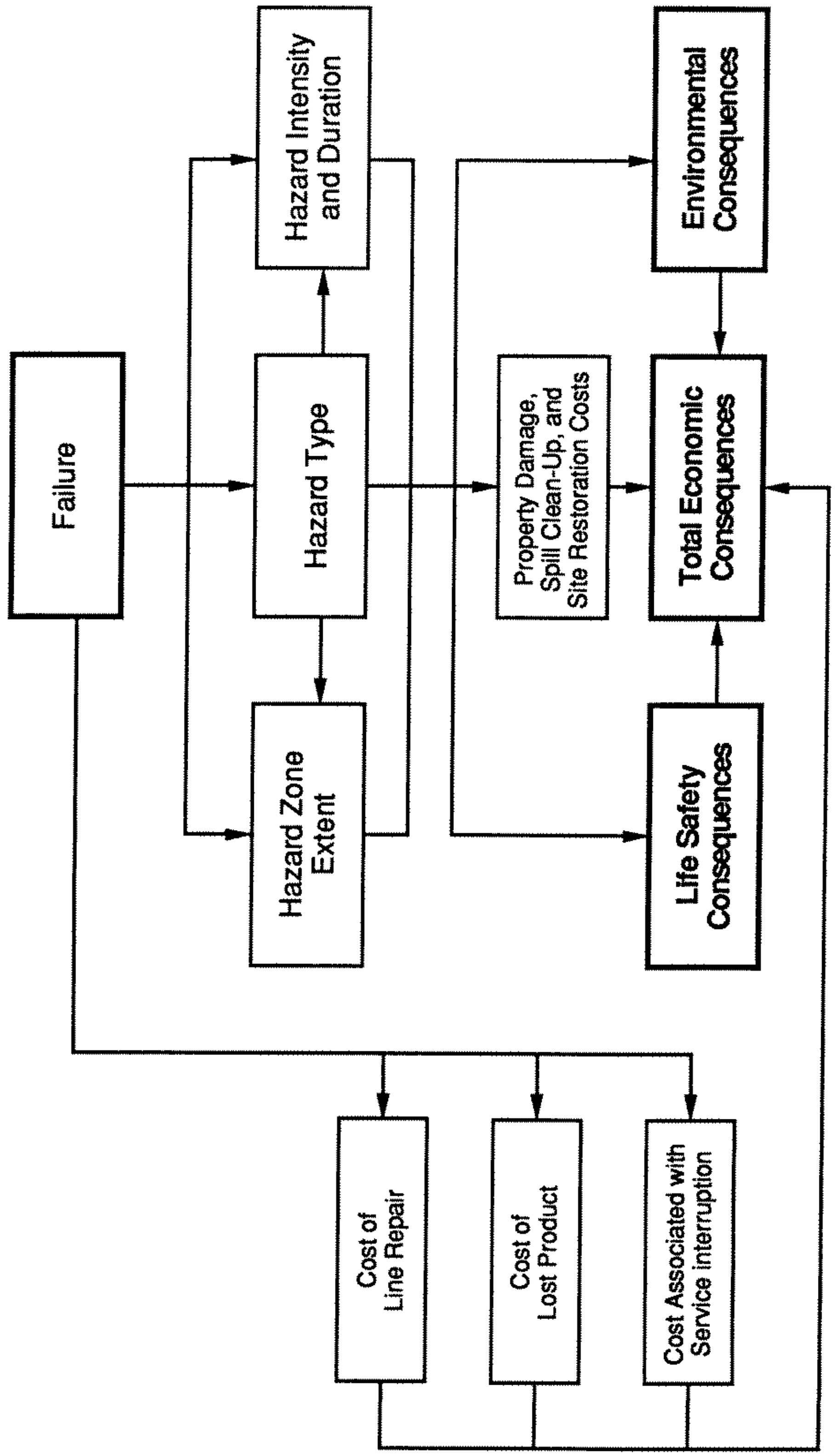


Figure 2.3 Consequences of pipeline failure.

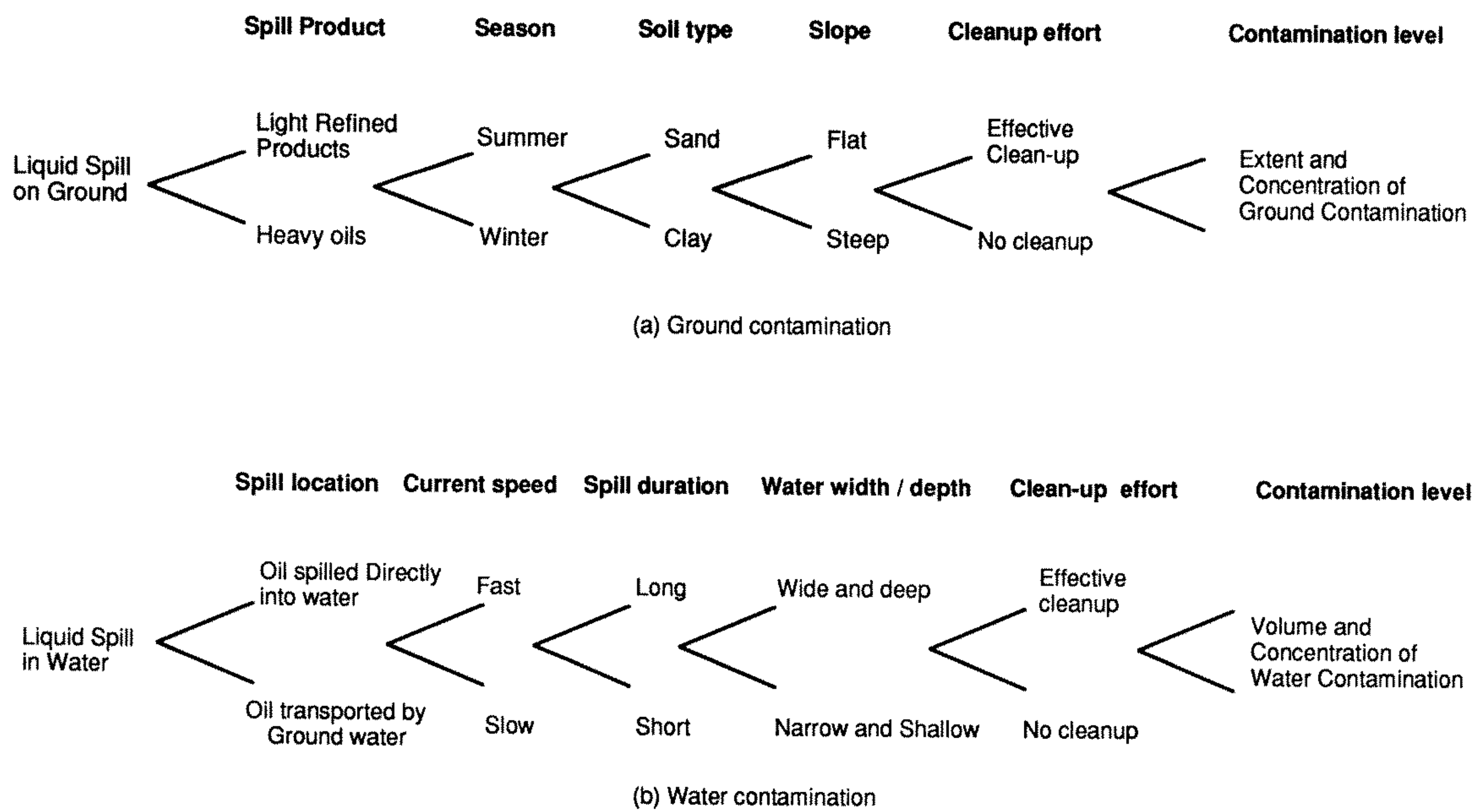


Figure 2.4 Factors influencing the level of ground and water contamination

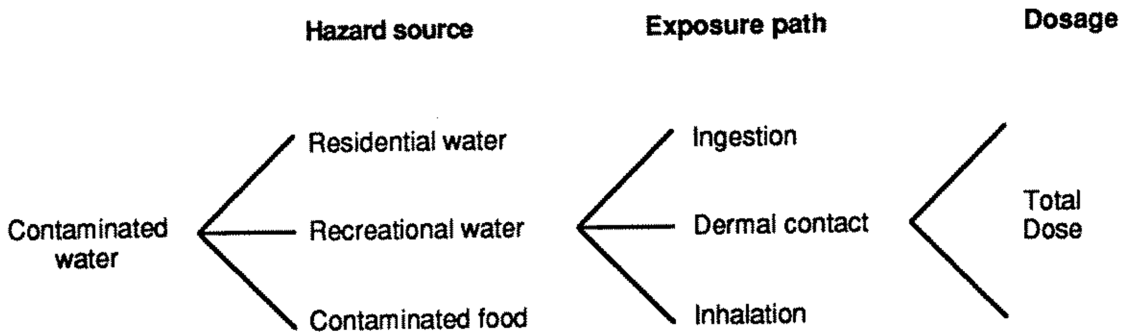


Figure 2.5 Human exposure pathway for water contamination.

<table>
<tr><th colspan="3">Product Type</th><th colspan="2">Natural Gas</th><th colspan="2">Hazardous Liquid</th></tr>
<tr><th colspan="3">Data Source</th><th>ERCB[1]</th><th>DOT[2]</th><th>ERCB[1]</th><th>DOT[3]</th></tr>
<tr><td rowspan="4">Outside Force</td><td rowspan="2">Mechanical Damage</td><td>Third Party</td><td>28%</td><td rowspan="2">34%</td><td>19%</td><td>23%</td></tr>
<tr><td>Construction/Maintenance</td><td rowspan="3">(Note 4)</td><td rowspan="3">(Note 4)</td><td>4%</td></tr>
<tr><td colspan="2">Ground Movement (e.g. slope failure, diff. movement)</td><td>3%</td><td>1%</td></tr>
<tr><td colspan="2">Other</td><td>3%</td><td>3%</td></tr>
<tr><td rowspan="4">Environmentally Induced Defects</td><td rowspan="2">Metal Loss Corrosion</td><td>External</td><td rowspan="4">40%</td><td>12%</td><td rowspan="4">38%</td><td rowspan="4">27%</td></tr>
<tr><td>Internal</td><td>5%</td></tr>
<tr><td colspan="2">Stress Corrosion Cracking (SCC)</td><td>1%</td></tr>
<tr><td colspan="2">Other (e.g. HIC, HSS, MIC)</td><td>1%</td></tr>
<tr><td rowspan="3">Material and Fabrication Defects</td><td colspan="2">Pipe Body</td><td rowspan="6">32%</td><td rowspan="3">10%</td><td rowspan="6">43%</td><td rowspan="3">8%</td></tr>
<tr><td rowspan="2">Welds</td><td>Seam Welds</td></tr>
<tr><td>Girth Welds</td></tr>
<tr><td rowspan="3">Other</td><td colspan="2">Operational Error</td><td>3%</td><td>6%</td></tr>
<tr><td colspan="2">Mechanical Component Failure</td><td>6%</td><td rowspan="2">28%</td></tr>
<tr><td colspan="2">Other</td><td>20%</td></tr>
<tr><td colspan="7">Note: 1. Energy Resource Conservation Board data (1980 - 1991)
2. U.S. Department of Transportation data (1984 - 1990)
3. U.S. Department of Transportation data (1982 - 1991)
4. Classified as "other" along with material/fabrication defects, operational error and miscellaneous</td></tr>
</table>

Table 2.1 Summary of relative failure probabilities by cause for natural gas and hazardous liquid pipelines.

Failure Cause	**Outside Force**		**Metal-Loss Corrosion**		**Crack-Like Defects**	
	Mech. Damage	Ground Move.	External	Internal	SCC	Welds
Pipeline System Attribute						
- land use	X					
- soil type		X	X		X	
- soil load-deformation response		X				
- ground movement mechanism		X	X			
- ground movement potential/extent		X	X			
- depth of cover		X				
- pipe axial-bending stiffness		X				
- soil corrosivity			X		X	
- ground water chemistry			X		X	
- ground water drainage character			X		X	
- operating stress level (static)					X	X
- operating stress variation (cyclic)					X	X
- pipe operating temperature			X	X	X	
- pipe age			X	X	X	X
- presence of casings			X			
- presence of electrical interference			X			
- product corrosivity				X		
- product abrasion potential				X		
- flow geometry				X		
- flow rate				X		
- pipe/weld material composition				X	X	
- pipe manufacturer/process			X		X	X
- pipe transportation method						X
- external coating type			X		X	
- external coating condition			X		X	
- cathodic protection level			X		X	
- internal coating type				X		
- internal coating condition				X		
- chemical inhibitors				X		
- depth of cover	X	X				
- extent of signage	X					
- right-of-way condition	X					
- right-of-way patrol frequency	X					
- one call system implementation	X					
- level of public consultation	X					
- presence of sub-surface marker	X					
- presence of mechanical protection	X					
- pipe diameter	X	X	X	X	X	X
- pipe wall thickness	X	X	X	X	X	X
- operating stress level	X	X	X	X	X	X
- pipe body yield strength	X	X	X	X	X	
- pipe body notch toughness	X				X	
- pipe body stress-strain response		X				
- seam weld type						X
- joint type		X				X
- weld metal strength		X				X
- weld metal & HAZ toughness		X				X
- permissible weld defect size		X				
- level of construction inspection		X	X		X	X
- initial hydrotest						X

Table 2.2 Attributes that affect the failure probability of buried pipelines.

Failure Cause	Outside Force		Metal-Loss Corrosion		Crack-Like Defects	
	Mechanical Damage	Ground Movement	External	Internal	SCC	Welds
Ground Based Inspection:						
- Right-of-Way Patrols [with confirmation excavations]	Indication [Measurement I]	Indication				
- Ground Movement Surveys		Measurement II				
- Pipe Movement Surveys		Measurement III				
- Close Interval Surveys [with confirmation excavations]	Indication [Measurement I]		Indication[1] [Measurement I]		Indication[1] [Measurement I]	
- Targeted Bell-Hole Excavation Program	Measurement I		Measurement I	Measurement I	Measurement I	
In-Line Inspection:						
- Low-Res. Geometry Tool [with confirmation excavations]	Indication [Measurement I]					
- High-Res. Position/Geometry Tool	Measurement III	Measurement III				
- Low-Res. Magnetic Flux Leakage Tool [with confirmation excavations]	Indication [Measurement I]		Measurement II [Measurement I&II]	Measurement II [Measurement I&II]		
- High-Res. Magnetic Flux Leakage Tool [with confirmation excavations]	Indication [Measurement I]		Measurement III	Measurement III		Indication[2] [Measurement I]
- Ultrasonic Tool	Measurement III		Measurement III	Measurement III		
- *Crack Detection Tool (technology under development)*					*Measurement III*	*Measurement III*
Proof Load - Hydrostatic Testing	Measurement IV		Measurement IV	Measurement IV	Measurement IV	Measurement IV[3]

Damage characterization terminology:

Indication - presence of defect indicated or inferred from inspection results

Measurement I - method provides selective high accuracy measurement of defects at excavation sites only

II - method provides continuous low accuracy measurement of defects

III - method provides continuous high accuracy measurement of defects; accuracy of measurement dependent on tool type & defect size

IV - method provides a measure of maximum defect size by eliminating all failure critical defects; number and size of remaining sub-critical defects not indicated but potentially increased by destructive nature of test

Notes:
1. method may not provide indication where coating shielding occurs
2. indication applies to circumferentially oriented defects (i.e. girth weld flaws) only
3. applies to longitudinally oriented defects (i.e. seam weld flaws) only

Table 2.3 Damage characterization capability of inspection methods applicable to buried pipelines.

Failure Cause	Outside Force		Metal-Loss Corrosion		Crack-Like Defects	
	Mech. Damage	Ground Move.	External	Internal	SCC	Welds
Damage Dependent						
- defect length	X		X	X	X	X
- defect effective depth	X		X	X	X	X
- local strain level		X				
Damage Independent						
- operating pressure	X	X	X	X	X	X
- pipe diameter	X	X	X	X	X	X
- pipe wall thickness	X	X	X	X	X	X
- pipe body yield strength	X	X	X	X	X	
- pipe body notch toughness	X				X	
- pipe body stress-strain response		X				
- weld metal strength		X				X
- weld metal & HAZ toughness		X				X
- permissible weld defect size		X				

Table 2.4 Parameters associated with pipeline failure prediciton models.

Failure Cause	Outside Force		Metal-Loss Corrosion		Crack-Like Defects	
	Mech. Damage	Ground Move.	External	Internal	SCC	Welds
Preventative Actions						
- enhance public awareness	X					
- improve R.O.W. condition	X					
- add signage	X					
- increase R.O.W. patrol frequency	X					
- install subsurface markers	X					
- install mechanical protection	X					
- increase burial depth	X					
- control ground movement potential		X				
- isolate pipe from grd. movement		X				
Remedial Actions						
- grind gouges & repair coating	X					
- grind gouges & install sleeve	X					
- perform cut-out replacement	X	X	X	X	X	X
- do multi-joint pipe replacement		X	X	X	X	
- hydrotest to remove critical defects	X		X	X	X	X
- deactivate, abandon & reroute		X	X	X	X	X
- enhance cathodic protection level			X			
- perform local coating repair	X		X			
- do multi-joint coating rehabilitation			X			
- install pressure containment sleeve			X	X		
- install prestressed sleeve			X			
- lower operating pressure			X	X	X	X
- pig to remove corrosive material				X		
- filter corrosive impurities				X		
- add corrosion inhibitor				X		
- introduce internal coating agent				X		
- adjust cathodic protection level					X	
- grind cracks & repair coating					X	
- grind cracks & install sleeve					X	

Table 2.5 Available maintenance alternatives for buried pipelines.

3.0 DEVELOPMENT OF A RISK-BASED DECISION-MAKING FRAMEWORK

3.1 Review and Assessment of Existing Risk-Based Methodologies

Risk analysis approaches currently employed in the pipeline industry were reviewed. The review covered recent work carried out by NOVA Corporation (Urednicek *et al.* 1992, Ronsky and Trefanenko 1992, and Morrison and Worthingham 1992), British Gas (Fearnehough 1985, and Fearnehough and Corder 1992), Arthur D. Little Limited (Hill 1992), DnV Technica (Weber and Mudan 1992), Dow Chemical (Muhlbauer 1992), Concord Environmental Corporation (Concord 1993), as well research sponsored by the American Gas Association (Kiefner *et al.* 1990) and the Gas Research Institute (Woodward-Clyde 1988, Kulkarni and Conroy 1991, and Kulkarni *et al.* 1993). The approaches given in these references are described in Appendix C. This section summarizes the conclusions of the review regarding the strengths and limitations of the different approaches with respect to their applicability to integrity maintenance decision-making.

Existing approaches can be grouped into two major classes: (1) qualitative approaches based on risk indices where factors that are thought to influence the probability and consequences of failure are subjectively rated and then added and/or multiplied together to give an indication of risk; and (2) quantitative approaches that estimate the level of risk based on direct estimates of the probability and consequences of failure.

The main limitation associated with qualitative index methods (*e.g.* Muhlbauer 1992 and Kiefner *et al.* 1990) is that the relative contributions of different factors that are thought to contribute to the total risk index are defined subjectively and are therefore potentially inaccurate. For example, Muhlbauer's index system accounts for the use of in-line inspection tools to identify metal loss corrosion by awarding up to 8 points out of a potential 400 representing resistance to failure (*i.e.* 2%). This underestimates the benefits of high resolution pigging which is known to result in significant reductions in the probability of corrosion failures which historically account for between 20 to 40% of all failures.

It is therefore considered that, in general, risk assessments based on index systems provide at best only an indication of the level of risk associated with a particular pipeline or segment. For the purpose of ranking line segments within a pipeline system according to the perceived level of risk (*i.e.* for segment prioritizing) this subjective approach may be acceptable, particularly where the data and/or models required for quantitative analysis are not available, but the inherent level of accuracy associated with a risk index approach is not thought to be sufficient to support a risk-based approach to integrity maintenance decision-making.

The major limitation associated with current quantitative risk assessment approaches is that they usually focus on a single aspect of the consequences associated with pipeline failure. Most existing approaches deal with either life safety risk (*e.g.* Concord 1993 and Hill 1992) or economic risk (Urednicek *et al.* 1992). Environmental damage risks associated with the failure of hazardous liquid pipelines have not been addressed quantitatively. In addition, the integration of life safety, environmental damage, and economic risks has not been addressed in previous work.

With regard to the accuracy of quantitative risk assessment approaches currently in use, it is noted that the estimation of probabilities is typically based on historical failure rates (*i.e.* a statistical approach). Publicly available databases do not generally allow subdivision of the failure data according to the attributes of a specific pipeline and where adequate subdivision is possible, the amount of data associated with a particular attribute set may be very limited because of the relatively rare nature of pipeline failures events. Failure probabilities estimated from public data are, therefore, not necessarily representative of the pipeline being considered. Depending on the format of data maintained internally by individual pipeline companies, it may be possible to improve on this aspect as has been done in a research program sponsored by the Gas Research Institute (Woodward-Clyde 1988) for cast iron pipelines.

In addition, the effect of a proposed integrity maintenance strategy on the probability of failure has not been adequately addressed in any of the currently available approaches. A limited amount of proprietary work has been conducted in this area by British Gas (Shannon and Argent 1988) and Novacorp (Ronsky and Trefanenko 1992). For the most part, however, methods that have been put forward for risk-based decision analysis of pipeline systems (*e.g.* Muhlbauer 1994) account for the effects of inspection and maintenance actions on risk levels in a subjective manner. They do not attempt to quantitatively account for the effects of specific inspection and maintenance activities on the rate of line failure. This quantitative aspect is essential if risk analysis is to be used as an objective basis for integrity maintenance decision-making.

A quantitative risk-based approach to decision analysis is currently being pursued in a research project sponsored by member companies of the Gas Research Institute for application to natural gas pipeline systems (Kulkarni and Conroy 1991, Kulkarni *et al.* 1993). The approach, which is being implemented in the form of a software program (PIMOS), is said to rely on historical data to assess the effects of inspection and maintenance activities on failure rates and will focus on the economic consequences of line failure. The proposed statistical approach to probability estimation is theoretically sound but it is not clear at this time whether a sufficiently large and pipeline attribute specific database can be assembled from project participant data to permit accurate assessment of the effects of candidate maintenance strategies on failure rates for different pipelines. In addition, while the environmental damage consequences of gas pipeline failure are generally not significant, the environmental consequences of liquid pipeline failures can be very significant and the potential life safety consequences for both gas and liquid lines can also be an important consideration in decision analysis. The relatively narrow focus of PIMOS on the economic aspects of gas pipeline failure consequences and the heavy reliance on historical pipeline performance data is therefore a potentially significant limitation of the overall approach.

3.2 Work Required to Implement Risk-Based Decision-Making for Integrity Maintenance

Existing risk analysis approaches have been designed to answer the following questions:

1. How do different pipeline segments compare with respect to overall risk?
2. Is the risk to life caused by a given pipeline segment acceptable?
3. Is the economic risk associated with a given pipeline segment acceptable?

The first question is typically answered using index systems, which are available as off-the-shelf tools, but as discussed previously, may lead to inaccurate results due to their subjective nature. The second and third questions are answered using quantitative risk assessment methods (subject to the previously mentioned limitations of historically-based failure probabilities), which typically require risk analysis expertise and proprietary tools. In general, most available approaches focus on relative risk evaluation or risk estimation under existing conditions but stop short of addressing risk reduction decision-making through integrity maintenance activities.

The focus of the present program is to answer the following questions:

- Which lines or line segments within a pipeline system present unacceptable levels of risk, or which segments would benefit the most from expenditures on risk reduction through integrity maintenance actions?
- Given that a critical pipeline or pipeline segment has been identified, what is the optimal set of integrity maintenance actions?

A comprehensive model that deals with both questions requires the following work (which effectively defines the scope of the present research program):

1. development of a risk-based decision-oriented framework;
2. modelling the effect of maintenance actions on the probability of failure; and
3. methodologies to combine life safety, environmental damage, and economic risks into one measure of failure consequences.

Figure 3.1 outlines the steps involved in risk-based integrity maintenance decision-making, highlighting the areas that require further work.

3.3 Basis for the Proposed Risk-Based Decision-Making Method

3.3.1 Basic Framework

Risk-based decision analysis approaches were assessed in order to determine the most suitable method to be used for risk-based integrity maintenance decision-making. It was decided that it is advantageous to use a formalized decision-making approach based on decision theory that can be computerized and delivered to the project participants. A formalized approach is desirable because it is systematic, consistent, and serves to document the process used to evaluate and finally make decisions. In addition, decision theory was selected because it is the most comprehensive approach for making decisions under uncertainty.

Optimization using decision influence diagrams was selected as the basic framework. The basic methodology and the building blocks of this approach are summarized in Figure 3.2.

A decision influence diagram is a graphical representation of a decision problem that shows the interdependence between the uncertain parameters that influence the required decision. A diagram consists of a network of nodes that represent random variables (*i.e.* uncertain quantities) and required decisions (*i.e.* choices that must be made). These nodes are interconnected by directed arcs or arrows. Arrows into random variable nodes indicate probabilistic dependence (*i.e.* that the value of the variable is effected by the variables or decisions at the other end of the arcs). Arrows into decision nodes specify information that is available at the time when the decision must be made. A decision influence diagram also contains a *value node* that represents the objective or value function that is to be maximized to reveal the optimal set of choices associated with the required decisions.

The evaluation of a decision influence diagram can be performed using a formal algorithm developed by Shachter (1986). The evaluation procedure consists of a sequence of transformations that remove nodes from the diagram until only the value node remains. At this point the solution algorithm will have determined the optimal set of decisions and calculated the value associated with that optimal decision set.

Decision influence diagrams were selected over other decision analysis methods because:

- they are ideally suited to structuring, representing and communicating the decision-making process for a given problem;
- they can be solved efficiently to indicate optimal choices; and
- they provide an excellent basis for a software graphical user interface that allows the user to have access to all intermediate and final results of the problem.

Decision theory as implemented using influence diagrams provides a formal approach to select options considering the probabilities of the possible outcomes of the decision and the associated consequences. Since probabilities and consequences are the two basic components of risk, this approach provides the ideal framework for risk-based decision-making. There are, however, different methods available to evaluate the expected consequences and these are discussed in the following section.

3.3.2 Criteria for Evaluating Choices

A consequence evaluation criterion represents a specific method of defining the *value node* shown in Figure 3.2. For example, if a purely economic criterion is considered appropriate, the value function would be defined in terms of the total cost and this corresponds to the well known cost optimization approach.

Different criteria for evaluating the consequences associated with integrity maintenance choices, within the risk-based framework described in Section 3.3.1, were analyzed. Emphasis was placed on identifying criteria that can address the combined effects of life safety, environmental, and economic consequences recognizing that each type of consequence is assessed or quantified in different terms.

It is proposed that two distinct approaches to consequence evaluation should be pursued, one based on *utility theory* and the other being a simple cost optimization approach with life safety and/or environmental damage constraints.

3.3.2.1 Utility Theory Approach to Evaluating Choices

Utility theory is a formalized approach that can be used to develop a comprehensive criterion that produces an optimal answer from the decision-maker's (*i.e.* operator's) point of view, assuming that there are no external constraints (*e.g.* regulations). The solution obtained when utility theory is employed in pipeline decision analysis is an optimal compromise between the different types of consequences (*i.e.* life safety, environmental, and economic).

If it is assumed, based on the premise developed in Section 2.2.2.2, that the consequences of pipeline failure can be measured in terms of: the number of fatalities ($\mathbf{N}$); the effective residual volume of spilled product ($\mathbf{V_e}$); and the total financial cost ($\mathbf{C}$); then multiattribute utility theory (Keeney and Raiffa 1976) can be used to define a value function

$$u = f(\mathbf{N}, \mathbf{V_e}, \mathbf{C})$$

which ranks different combinations of $\mathbf{N}$, $\mathbf{V_e}$, and $\mathbf{C}$ according to their perceived overall impact. The optimal decision is the one that maximizes the expected value or utility (see Figure 3.3).

Furthermore, utility theory can be used to define the form of the effective residual spill volume function, described previously in Section 2.2.2.2 as

$$\mathbf{V_e} = f(\mathbf{V_r}, \mathbf{S_v})$$

where $\mathbf{V_r}$ is the residual spill volume, and $\mathbf{S_v}$ is a spill impact factor. In addition, utility theory can also be used to define the spill impact factor as a function of characteristic spill attributes.

The advantages of utility theory are as follows:

- It allows for formal consideration of *trade-offs* between different types of consequences. For example, it can be used to rank two options, one involving a low cost and a high expected degree of environmental damage and the other involving a higher cost and a lower expected degree of environmental damage.
- It quantifies such attitudes as *risk aversion*. For example, the negative impact of one incident causing 100 casualties is much more severe than the impact of 100 separate incidents, each causing one casualty.
- Soft parameters such as public outrage can be incorporated (on a subjective basis).

The difficulties associated with applying utility theory are associated with defining trade-off values (*e.g.* the price of a human life). Decision makers may be reluctant to address these issues directly and companies may find them difficult to present to regulators.

3.3.2.2 Constrained Cost Optimization Approach to Evaluating Choices

Constrained cost optimization assumes that life safety and environmental damage criteria are to be treated as constraints that are likely to be set by regulators or defined on the basis of societal precedents. Within these constraints, the solution that produces the least expected total cost is selected. It is also possible to introduce a maintenance budget limitation as a constraint on the optimization process.

This approach is illustrated in Figure 3.4, which shows a typical risk vs. cost curve being optimized subject to a maximum allowable risk to life and a maximum maintenance budget. In Figure 3.4a, the optimal solution meets the life risk criterion and can be achieved within budget. In Figure 3.4b, the optimal solution does not meet the life risk criterion. In this case, the most economical option leading to adequate life safety should be selected (even though it is not optimal).

The advantage of this approach is that trade-offs between cost on the one hand and life safety and environmental protection on the other are not necessary. The operator demonstrates prudent risk management with respect to life and the environment by meeting recognized acceptable risk levels. For example, acceptable life safety risks have been proposed by various European government agencies such as the Health and Safety Executive in the United Kingdom (HSE 1989). In Canada draft guidelines outlining acceptable life-safety risk levels for pipeline corridors have been developed by the Major Industrial Accident Council of Canada (MIACC 1993).

The disadvantage of the constrained cost optimization approach is that the decisions reached may not be optimal from the operator's point of view. In particular this may be the case for existing pipelines that require unrealistic expenditures to meet recognized life safety and/or environmental protection criteria.

3.3.2.3 Preferred Approach to Evaluating Choices

It should be recognized that for pipelines in remote areas that are not environmentally sensitive, cost is the major consideration. In these cases, both of the above approaches reduce to a simple cost minimization criterion.

For pipeline segments where life safety and/or environmental damage issues are significant, it is believed that the concept of utility optimization provides the most suitable method of reaching decisions that are consistent with the decision-maker's values and preferences. On the other hand the constrained cost optimization approach is likely to be more acceptable to managers and regulators.

It is proposed that for a specific application, the constrained cost optimization approach should be attempted first and used if it provides an adequate solution. If this approach proves to be impractical, then the utility approach should be adopted. It is expected that applying the utility approach will provide useful insights into the problem of consequence evaluation and that as its benefits are demonstrated, it will become more acceptable to decision-makers.

Figures

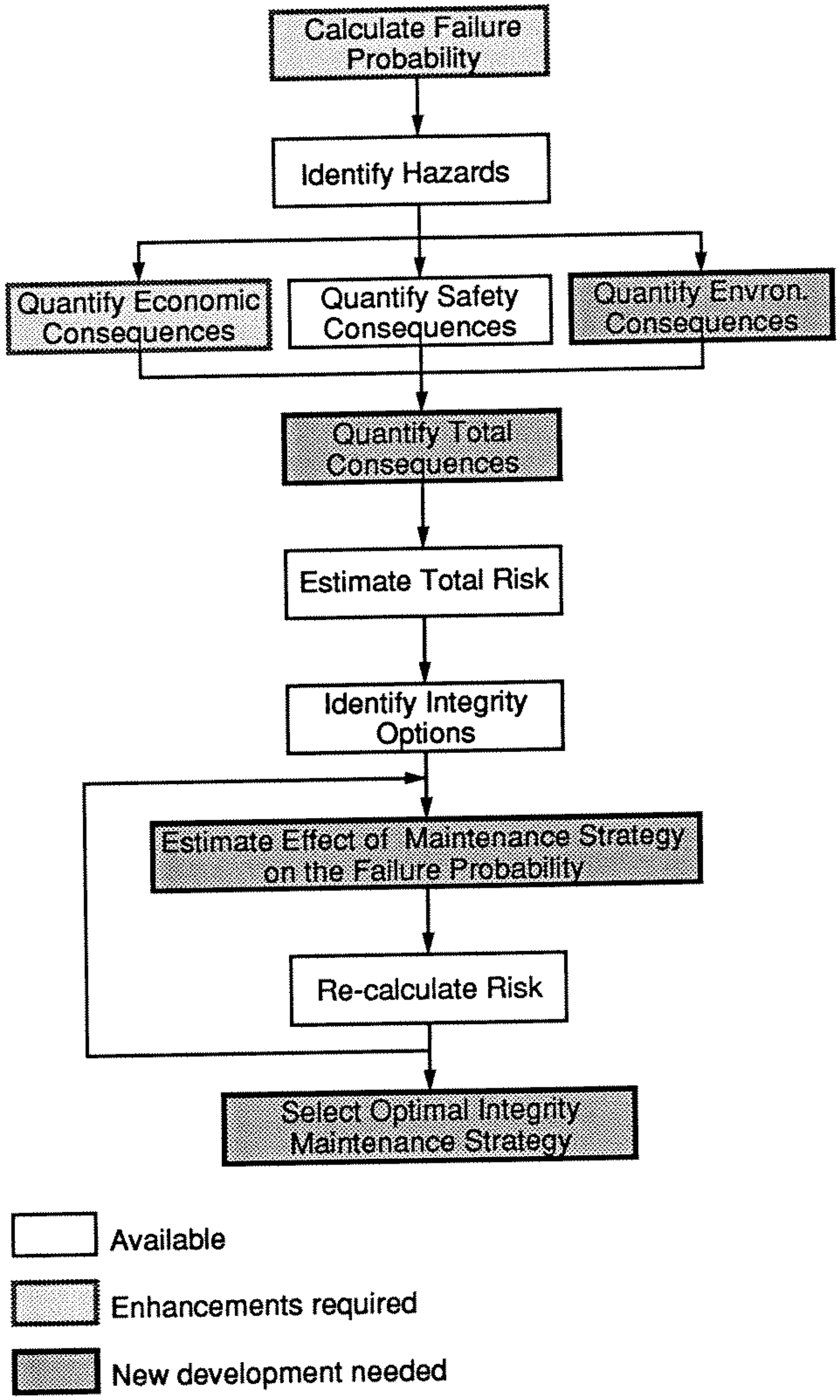
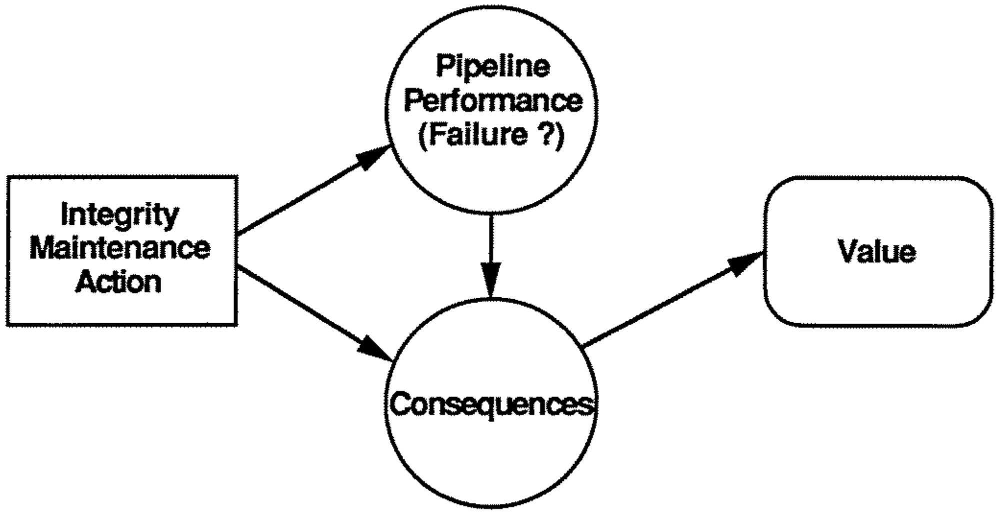


Figure 3.1 Steps in risk-based integrity maintenance optimization.



Decision node: Indicates a choice to be made
Example: Run a high or low resolution pig

Random variable node: Indicates uncertain parameter or event
Example: How will the pipeline perform in the next year ?
(safe, leak or rupture)

Value node: Indicates the criterion used to evaluate consequences

Arrow: Indicates probabilistic dependence
Example: The final consequences depend on the costs associated with the maintenance action taken and the performance of the pipeline

the *Optimal Decision* is the one giving the highest expected value

Figure 3.2 Basic framework for integrity maintenance decision-making using influence diagrams.

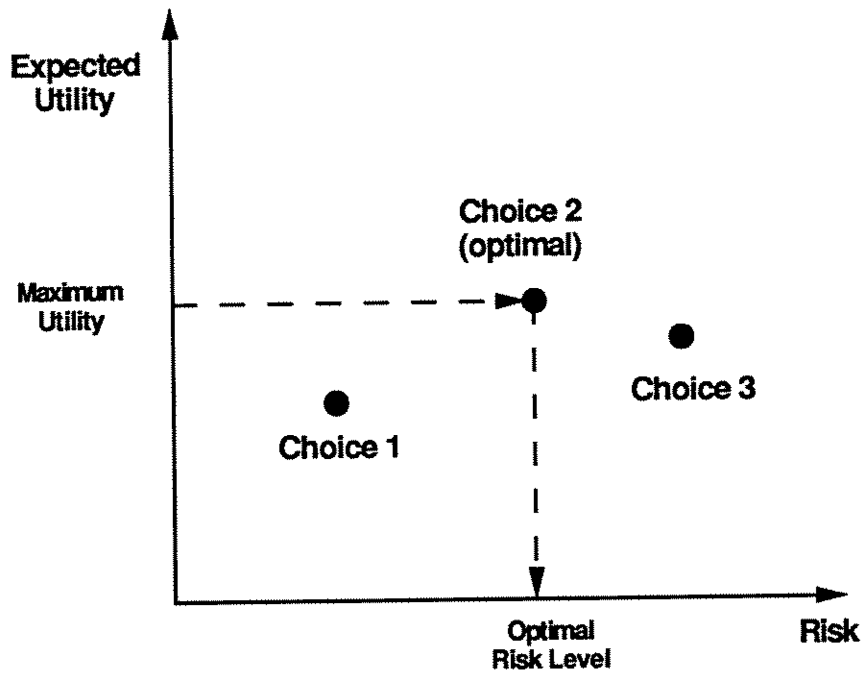
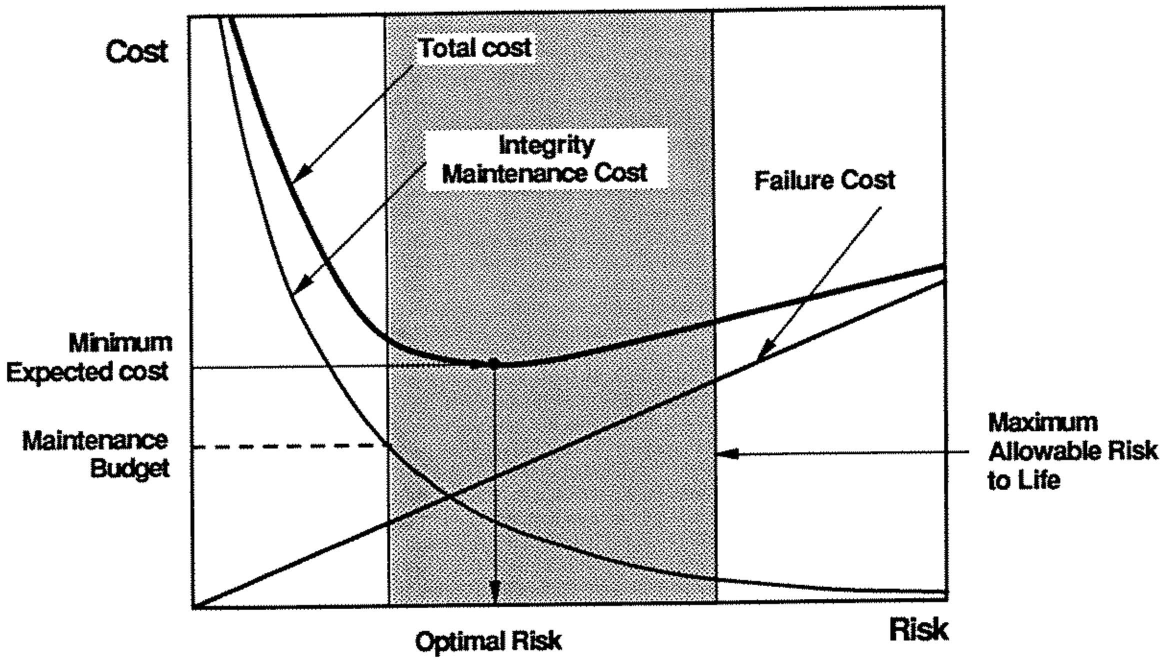
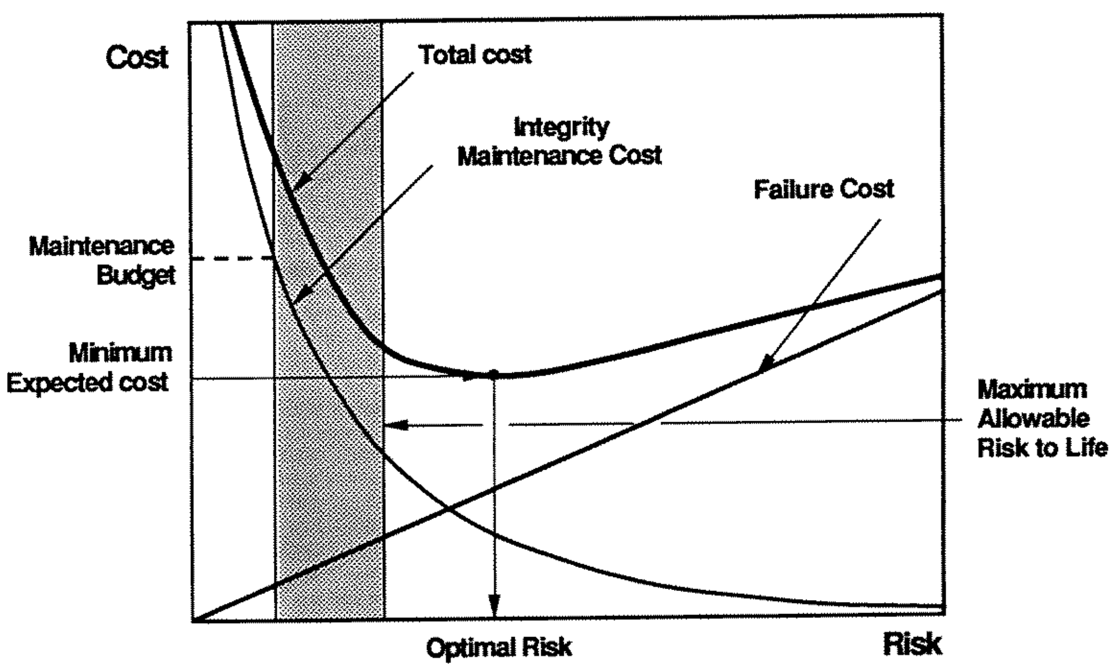


Figure 3.3 Illustration of the utility optimization approach.



a) Optimal Solution Meets Cost and Life Risk Constraints
(Choose Optimal Solution)



b) Optimal Solution Does not Meet Life Risk Constraint
(Choose Maximum Allowable Risk to Life)

Figure 3.4 Illustration of the constrained cost optimization approach.

4.0 PROPOSED METHODOLOGY FOR RISK-BASED DECISION-MAKING

4.1 Overall Framework

The proposed framework for risk-based optimization of pipeline integrity maintenance activities is intended to: (1) identify pipelines or line segments within a pipeline system that present unacceptable levels of risk and/or to identify segments that would benefit the most from expenditures on risk reduction through integrity maintenance activities; and (2) assess available maintenance alternatives to determine the optimal set of integrity maintenance activities for each targeted segment.

The framework involves analysis that can logically be divided into five distinct and sequential stages. The different stages of analysis, and the sequence in which they are to be carried out is illustrated by the flow chart shown in Figure 4.1. A description of the analysis required at each stage is as follows:

System definition - the pipeline system as a whole, or the portion of interest, is sub-divided either into segments that possess common attributes, or into segments with varying attributes that will by necessity or preference be inspected and maintained as a unit. The preferred approach is subdivision by attribute commonality because the segment ranking and decision analysis results will then apply equally to all points along each segment. Where subdivision according to criteria other than attribute commonality is adopted, it is recognized that the segment ranking and decision analysis results will reflect an averaging process that accounts for variations in failure rates and failure consequences along the length of segments so defined.

System prioritization - the individual segments of pipeline, delineated in the previous analysis stage, are subjected to quantitative risk assessment, the objective of which is to estimate the level of risk associated with each significant potential failure cause. As an option, the facility is provided to incorporate a subjective estimate of the cost and potential effectiveness of maintenance actions directed at risk reduction. The intention of this prioritization stage is to rank pipeline segments and associated failure causes by the level of risk and optionally by an approximate estimate of the incremental cost of risk reduction, thereby identifying (or targeting) specific segments and associated failure causes for subsequent detailed analysis. The steps involved in prioritization based on quantitative risk assessment are outlined in the flow chart shown in Figure 4.2.

Decision analysis - segments and associated failure causes, targeted by system prioritization in the preceding stage, are subjected to formal decision analysis. In the analysis the current extent of line damage or damage potential is estimated and candidate maintenance strategies are evaluated to obtain an estimate of their likely effect on the existing or potential extent of line damage, the intent of which is to permit calculation of the current level of risk and the degree of risk reduction associated with each maintenance strategy. The risk reduction potential and cost of implementation associated with each candidate maintenance strategy is then evaluated using a value function based on utility theory or constrained cost optimization to reveal the optimum maintenance strategy for the segment and failure cause in question. For each segment and associated failure cause subjected to decision analysis, the incremental cost of risk reduction associated with the optimal maintenance strategy is then calculated for subsequent use in the next stage of analysis. The steps involved in integrity maintenance decision analysis are summarized in the flow chart shown in Figure 4.3.

Note that the focus of decision-making in this program will be on optimization of near-term integrity maintenance actions (*i.e.* what to do next) as opposed to optimization of long-term action sequences that cover the remaining life of the system. The emphasis on near-term optimization reflects the following basic assumptions: (1) that over the long-term the most efficient approach is to simply repeat the analysis after one choice is implemented to decide on the next action; and (2), that in the current context, the uncertainties associated with inspection methods, defect growth models, failure prediction models, etc., are potentially too large to make long-term performance extrapolations meaningful.

Refinement of system prioritization - an alternate ranking of targeted segments and associated failure causes is developed based on the incremental cost of risk reduction associated with the optimal maintenance strategy as determined in a rigorous, objective manner in the previous stage of analysis using decision analysis (as opposed to the optional subjective assessment offered at the initial prioritization stage). Note that this refined ranking of segments applies only to segments and associated failure causes that were targeted in the initial prioritization stage and subsequently evaluated using decision analysis.

Maintenance Implementation - a plan is developed for implementation of the optimal maintenance strategy identified for each targeted segment and associated failure cause in order of decreasing level of total risk or in order of increasing cost of risk reduction.

Most of the analysis effort associated with the proposed methodology is directed at decision analysis and to a somewhat lesser extent system prioritization. A more comprehensive discussion of the work involved in these two areas is provided in the following section.

4.2 Key Components of Framework

4.2.1 System Prioritization

The prioritization process, as envisioned in this project, is described by the detailed flow chart shown in Figure 4.4 which provides the basic outline for a proposed pipeline prioritization software program. The program consists of several distinct modules that perform the following tasks based on the attributes assigned to each segment:

- a **failure rate estimation module** that is intended to estimate the failure rates and the relative leak vs. rupture probabilities associated with each significant potential failure cause (*i.e.* third party damage, ground movement, external and internal metal loss corrosion, stress corrosion cracking, weld cracking, and other);
- a **consequence assessment module** that assesses the potential hazards (*i.e.* jet fire, flash fire, pool fire, explosion, toxic cloud, and liquid spill), estimates their effect on the three consequence components (*i.e.* life safety, environmental damage, and financial cost) and combines the individual consequence components into a single measure of loss using an appropriate value function, or in this context, loss function;
- a **risk estimation module** that calculates the overall level of risk associated with each failure cause by summing the individual combined risk components associated with leak and rupture for each hazard type;

- an *optional* **cost of risk reduction module** that allows the user to input subjective estimates of the likely cost of risk reduction and the anticipated corresponding reduction in failure rate for each specific segment and failure cause which can then be used to estimate the cost associated with a unit reduction in failure risk (*i.e.* the incremental cost of risk reduction); and
- a **segment ranking module** that tabulates the calculated risk (and optionally the incremental cost of risk reduction) for each segment, and for each segment and specific failure cause, and then sorts the segments by level of risk (and optionally by incremental cost of risk reduction).

The consequence assessment module, risk estimation module and segment ranking module are all relatively conventional applications of existing risk analysis techniques (with the exception of the proposed value function required for combining consequences which is described in Section 3.3.2). However, the failure rate estimation module and the cost of risk reduction module warrant further explanation.

The failure rate estimation module is envisioned to provide estimates of cause-specific failure probabilities using a statistical approach based on historical data. For the prioritization process to be meaningful (*i.e.* rational, objective and consistent), the output from the failure rate estimation module must be failure rate estimates that reflect the specific attributes of the line segment under investigation. The accuracy of the failure rate estimates will depend on the size of the historical database that can be assembled and the degree to which the available historical line failure data can be subdivided to give probability estimates applicable to specific attribute combinations.

It is proposed that the failure rate estimation module can be seeded with failure cause-specific and pipeline attribute-specific failure rate estimates based on publicly available data (*i.e.* a synthesis of the data compiled by the NEB and the ERCB in Canada, and the DOT in the United States). It is further proposed that deficiencies in the data (*i.e.* lack of sufficient historical data on the impact of selected line attributes on failure rates) can be addressed by incorporating subjective failure rate estimates obtained using expert judgement to adjust available historical data to reflect the expected effects of specific line attributes.

Alternatively, the prioritization program will facilitate the input of proprietary company data on failure rates to tailor the failure rate estimation module to company specific line attribute sets and thereby enhance the validity of the prioritization process.

A cost of risk reduction module has been included in the prioritization program to facilitate the early development of an alternate prioritization list which targets segments with the highest potential for risk reduction for a given cost. It requires the input of an estimate of the amount by which the failure rate for a given cause can likely be reduced through appropriate integrity maintenance action and an estimate of the cost associated with that maintenance activity (*e.g.* an expenditure of approximately 'm' dollars on high-resolution in-line inspection of a particular segment is thought to virtually eliminate the probability of failure due to metal loss corrosion in the near term). From these input parameters the cost of a unit reduction in risk, or the incremental cost of risk reduction, can be calculated.

It is recognized that the input required to estimate the incremental cost of risk reduction will not be readily available to the user in a quantitative, objective form at this stage in the analysis process; in fact, it is the purpose of the integrity maintenance decision analysis program to determine this information for the optimal maintenance strategy in a rigorous manner. It is noted, however, that assessment of the incremental cost of risk reduction by formal decision analysis will only be carried out on segments that have been targeted at the prioritization stage. It is considered that subjective estimates of the cost of risk reduction, made at the initial prioritization stage based on the judgement of experienced operators, will provide useful insight and an alternate perspective on prioritization which may have an influence on the number of segments that are targeted for detailed integrity maintenance decision analysis.

4.2.2 Decision Analysis

The analysis approach proposed for integrity maintenance decision-making, based on influence diagrams as described in Section 3.3.1, is illustrated conceptually by the diagrams shown in Figure 4.5. Two diagrams are presented, one for decision analysis of inspection and maintenance strategies that are directed at existing damage (*e.g.* corrosion pits, SCC and other crack-like defects, and excessive longitudinal strain due to ground movement) and the other for inspection and maintenance strategies directed at potential damage (*i.e.* mechanical damage).

Note that both of the conceptual models involve similar sets of uncertain parameters with similar interrelationships and dependencies. This implies that the same overall decision analysis framework can be applied to the assessment of all relevant pipeline inspection and maintenance activities.

In general terms, the diagrams show that the value associated with a particular inspection and maintenance action is dependent upon the associated consequences which are directly dependent on the choice of action (*i.e.* the inspection and maintenance costs) as well as on the segment performance (*i.e.* failure rate as it effects the hazard related consequences including: number of fatalities, effective residual spill volume, and hazard related costs). The segment performance is dependent on the damage extent (or damage potential) remaining after inspection and maintenance actions are taken, which in turn depends on the initial extent of damage (or damage potential) as well as on the choice of inspection and maintenance action.

In the context of decision analysis using an influence diagram approach, the calculation of segment performance as a function of damage extent and candidate integrity maintenance actions will be carried out using an analytical approach to reliability analysis as described in Section 2.2.1.2.2. Recall that this approach is based on the use of deterministic failure prediction models and probabilistic analysis that accounts for the effect on failure rate of uncertain quantities, including pipeline damage extent (as determined from direct inspection or inferred from previous inspections), pipeline operating conditions, and line pipe mechanical properties. The calculation of the consequences associated with candidate integrity maintenance actions will be carried out in a similar manner taking into account the uncertainty associated with the parameters that influence both the failure hazards and the impact of those hazards on the number of casualties, the extent of environmental damage, and the overall financial cost.

A more detailed description of the decision-making process for inspection and maintenance actions directed at existing damage is given by the influence diagram shown in Figure 4.6. This diagram shows the inspection and maintenance decision node broken down into three distinct components: 1) the choice of inspection method; 2) the choice of a defect repair criterion; and 3) the time to next inspection. The diagram also shows the sequence in which the choices are made and the parameters that have an influence on the down-stream choices (including the information that is known prior to making those choices). Note that the addition of the 'time to next inspection' decision node is a necessary refinement that reflects the impact on the decision-making process of the time dependent nature of the damage extent for existing defects (*i.e.* the defect growth rate).

Note also that the diagram suggests that decision analysis will be directed at determining what action should be taken in the immediate future and potentially how long until that action should be repeated (or by implication, how long until the decision analysis problem should be revisited). As noted previously, this implies that the focus of decision-making is on optimization of near-term integrity maintenance actions as opposed to long-term actions.

The consequence node in Figure 4.6 is further expanded in Figure 4.7 to show the parameters that effect the life safety node (number of casualties), the environmental damage node (spill characteristics), and the economic consequence node (total cost), each of which have an impact to the value node. Note that, as drawn, the node set within the expanded consequence node is made up of several so-called compound nodes (*e.g.* release characteristics and conditions at failure) each of which represents a related set of uncertain parameters. The compound node is employed in Figures 4.5 through 4.7 as an explanatory convenience. For the influence diagram to be solvable, all compound nodes must be expanded to a set of nodes that each represent a single uncertain quantity.

A full expansion of the influence diagram required for integrity maintenance decision analysis (*e.g.* expansion of all compound nodes in Figures 4.6 and 4.7) results in a very complex diagram with a large number of interdependent nodes. However, recall from Section 3.3.1 that an influence diagram representing a particular integrity maintenance decision analysis problem can be solved efficiently using a formal algorithm that automatically performs all of the inference and analysis and recall further that the solution algorithm is ideally suited to implementation in the form of a software program.

The proposed decision analysis approach therefore involves the development of a software program that will define the integrity maintenance decision analysis problem in terms of an influence diagram similar to the conceptual diagrams shown in Figures 4.5 through 4.7 and implement a solution algorithm to determine the optimal value and the associated optimal decision set. The program will be structured to define the value node using a value function based on either utility theory, in which case the resulting decision set will be an optimal compromise between the different types of consequences (*i.e.* life safety, environmental, and economic), or based on economic consequences only where the decision set will be associated with cost optimization, potentially constrained by limits on life safety risk and/or environmental damage risk, and possibly by maintenance budget limitations. The user interface will be a graphical representation of the appropriate decision influence diagram through which the user will have access to all nodes for input parameter definition and output review.

4.3 Framework Implementation Requirements

Implementation of the proposed methodology for risk-based pipeline prioritization and integrity maintenance decision analysis requires the development of software programs that involve a number of probabilistic and deterministic models which make use of significant amounts of historical and pipeline-specific data.

The major probabilistic model components required include an influence diagram builder/solver (see Section 3.3.1) and a probability integration model (see Section 2.2.1.2.2). The data required for the probabilistic modelling includes: a historical failure database (see Section 2.2.1.2.1); statistical descriptions of relevant pipeline attributes such as operating pressure, material properties and dimensions; as well as performance data for different inspection and failure prevention methods (see Section 2.2.1.2.2).

The deterministic components required include release hazard and consequence evaluation models (see Section 2.2.2.2), as well as models that predict failure based on pipeline attributes and inspection results (see Section 2.2.1.2.2). In addition, some subjective models are required to rank the environmental seriousness of product releases and to combine life safety, environmental damage, and economic aspects into a unified measure of consequences (Section 3.3.2).

The required models and data have been assessed for availability and suitability for incorporation in the risk-based framework in the sections referenced in the above paragraphs. The major conclusion of this assessment is that sufficient information is available, or likely to become available in the near future, to indicate that the risk-based decision analysis model can be successfully developed. With careful planning, the model can take full advantage of existing information to produce useful immediate outputs. New developments can be incorporated as they become available to expand the system into a complete integrity maintenance prioritization and decision analysis tool.

The following sequence of development is proposed as one that makes good use of existing information, produces useful intermediate results and is capable of incorporating new information to produce the complete decision analysis system:

1. **Probabilistic decision analysis model**. This involves the development of a decision influence diagram builder and solver that incorporates a probability integration method such as FORM or Monte Carlo simulation. The model is the central component of the proposed risk-based decision analysis methodology. Development can be based on established technology which will require some extensions to suit the specific requirements of this project.
2. **Consequence assessment model**. This involves the development of a deterministic model to estimate the individual consequence components associated with line failure and to combine the individual components into a global measure of loss. The model is a necessary component of risk analysis and in combination with Model 1 (the probabilistic decision analysis model) it can be used as a risk assessment tool and a preliminary decision analysis tool if failure probabilities are user defined. Development can be largely based on established information except that subjective models will have to be developed to rank the environmental seriousness of product releases and to combine life safety, environmental damage, and economic aspects into a unified measure of consequences.
3. **Prioritization model**. This model incorporates Model 2 (the consequence assessment model) and some preliminary characterization of failure probabilities and possibly subjective estimates of the effectiveness of integrity maintenance actions to permit the ranking of individual pipeline segments according to risk level and expected cost of risk reduction. The required failure probability information can be based mostly on historical failure rate data which is likely sufficient to provide the accuracy required for system prioritization. Implementation will require the collection and analysis of public (and where possible company specific) failure incident data and pipeline exposure data.
4. **Optimization model**. This model incorporates Model 1 (the decision analysis model) and Model 2 (the consequence assessment model) and builds on the results obtained from Model 3 (the prioritization model). The model should be developed and incorporated into the overall framework on a failure cause by failure cause basis (*e.g*. metal loss corrosion,

third party damage, ground movement, SCC, etc.). The sequence of development can be based on availability of required information and perceived importance of the failure mechanism.

Figures

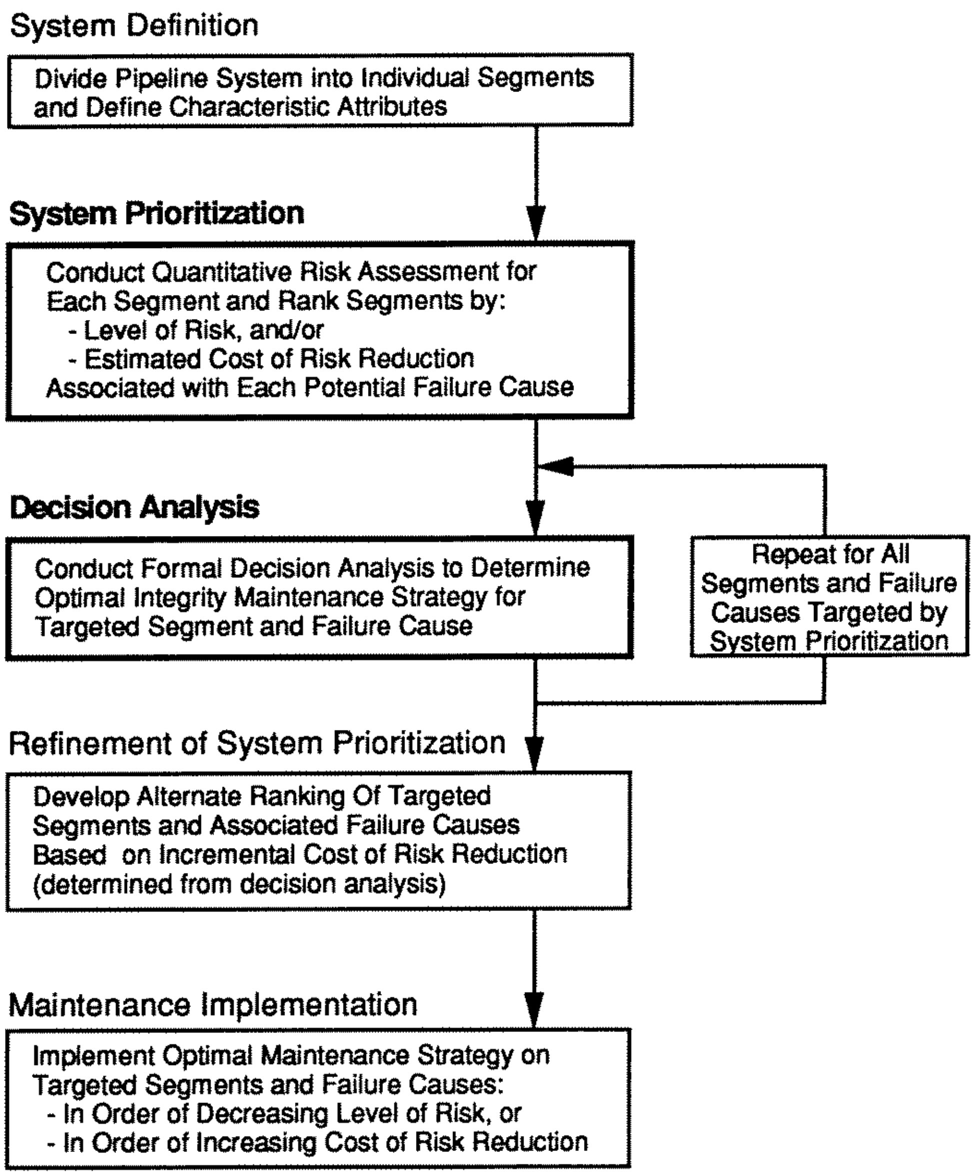


Figure 4.1 Proposed framework for risk-based optimization of pipeline integrity maintenance activities.

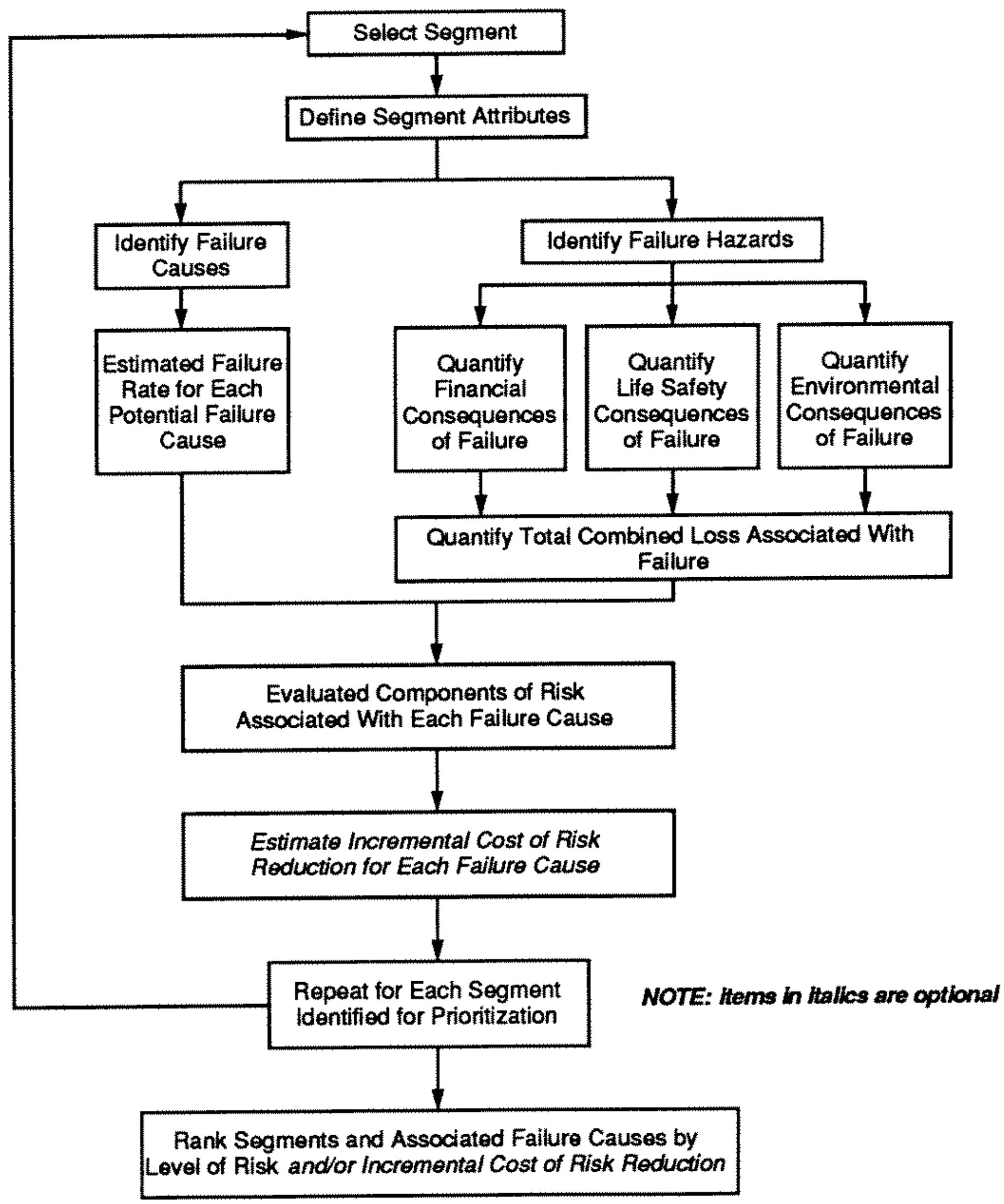


Figure 4.2 Flow chart for pipeline system prioritization.

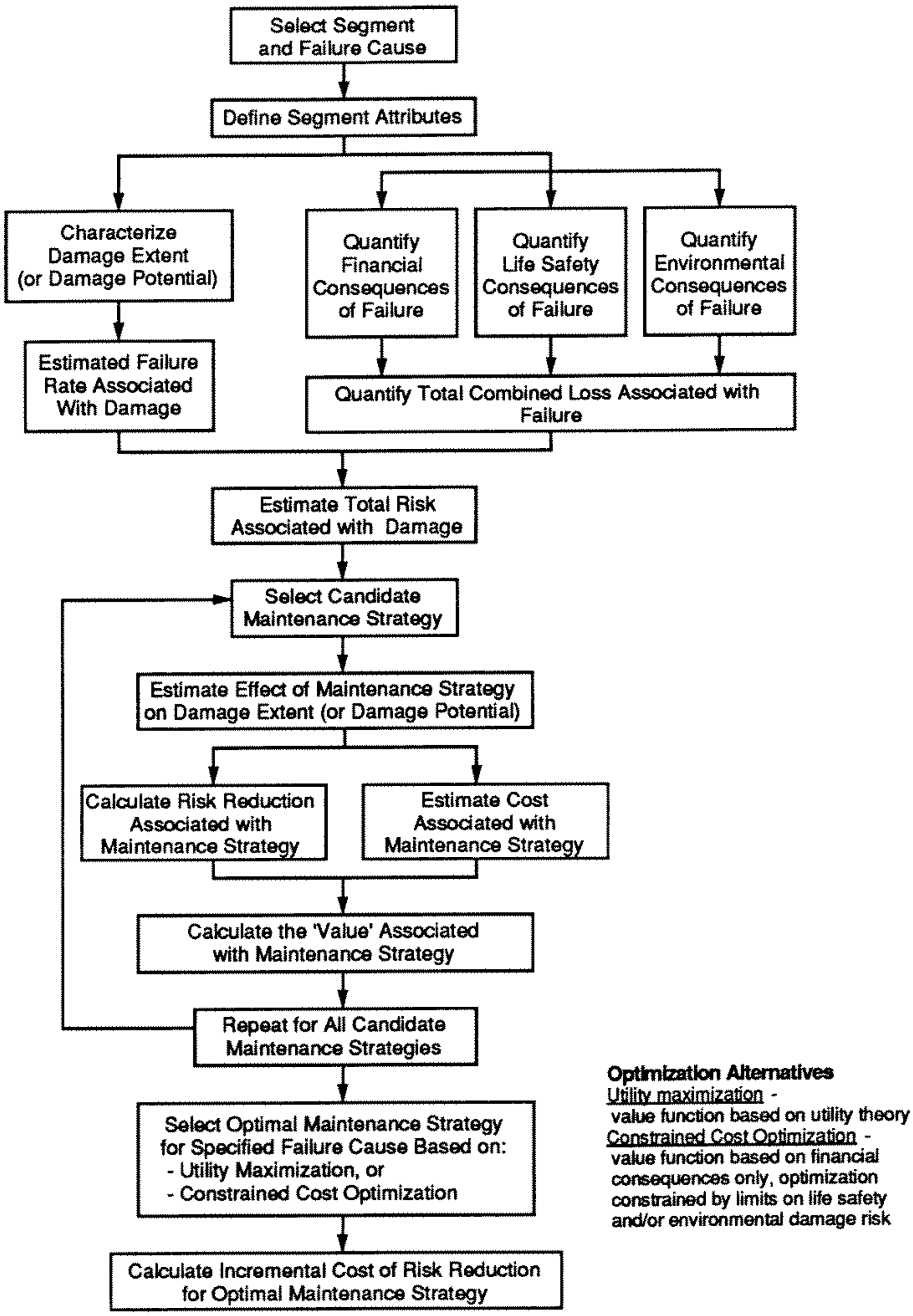


Figure 4.3 Flow chart for integrity maintenance decision analysis.

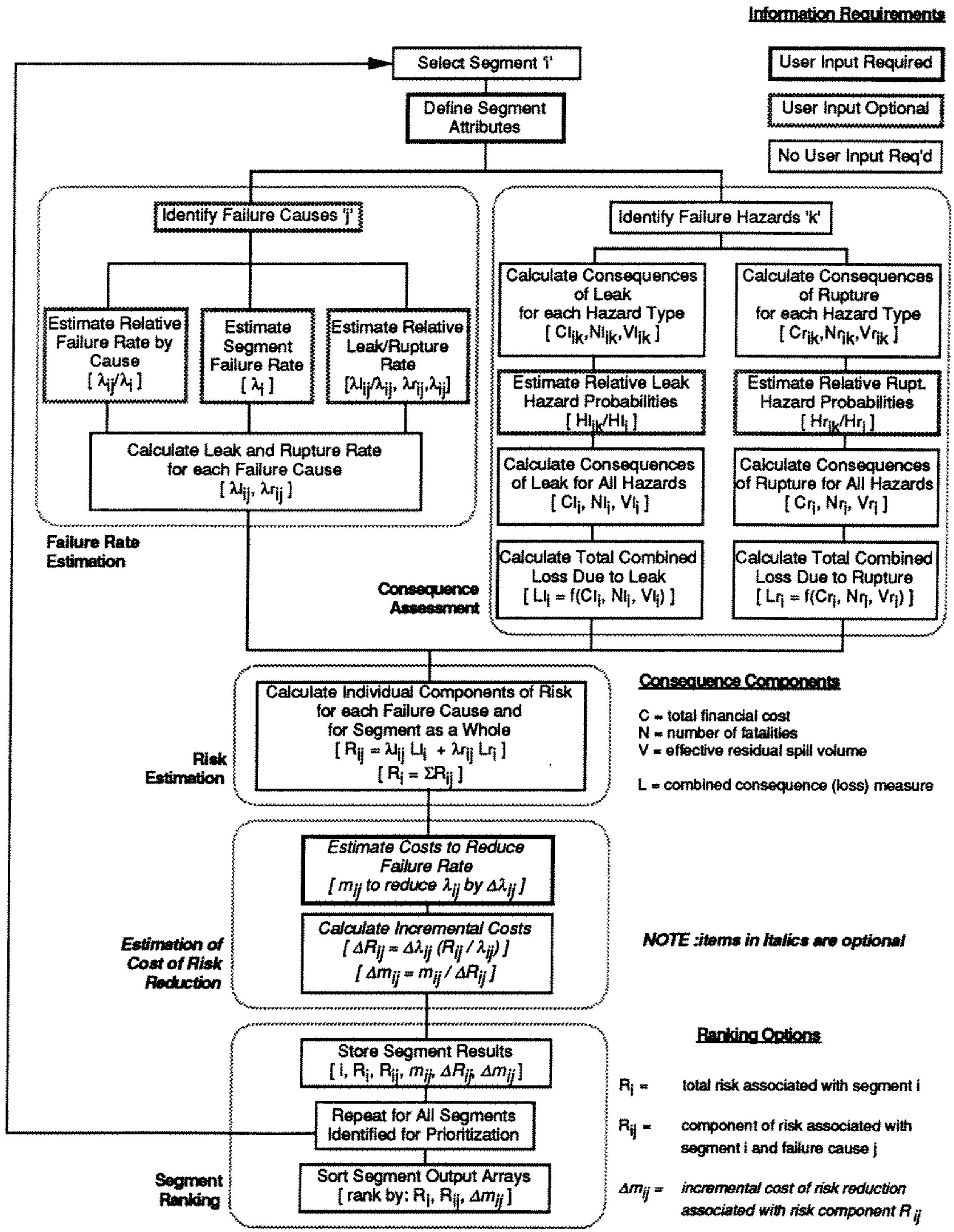


Figure 4.4 Detailed flow chart outlining pipeline system prioritization program F4.4

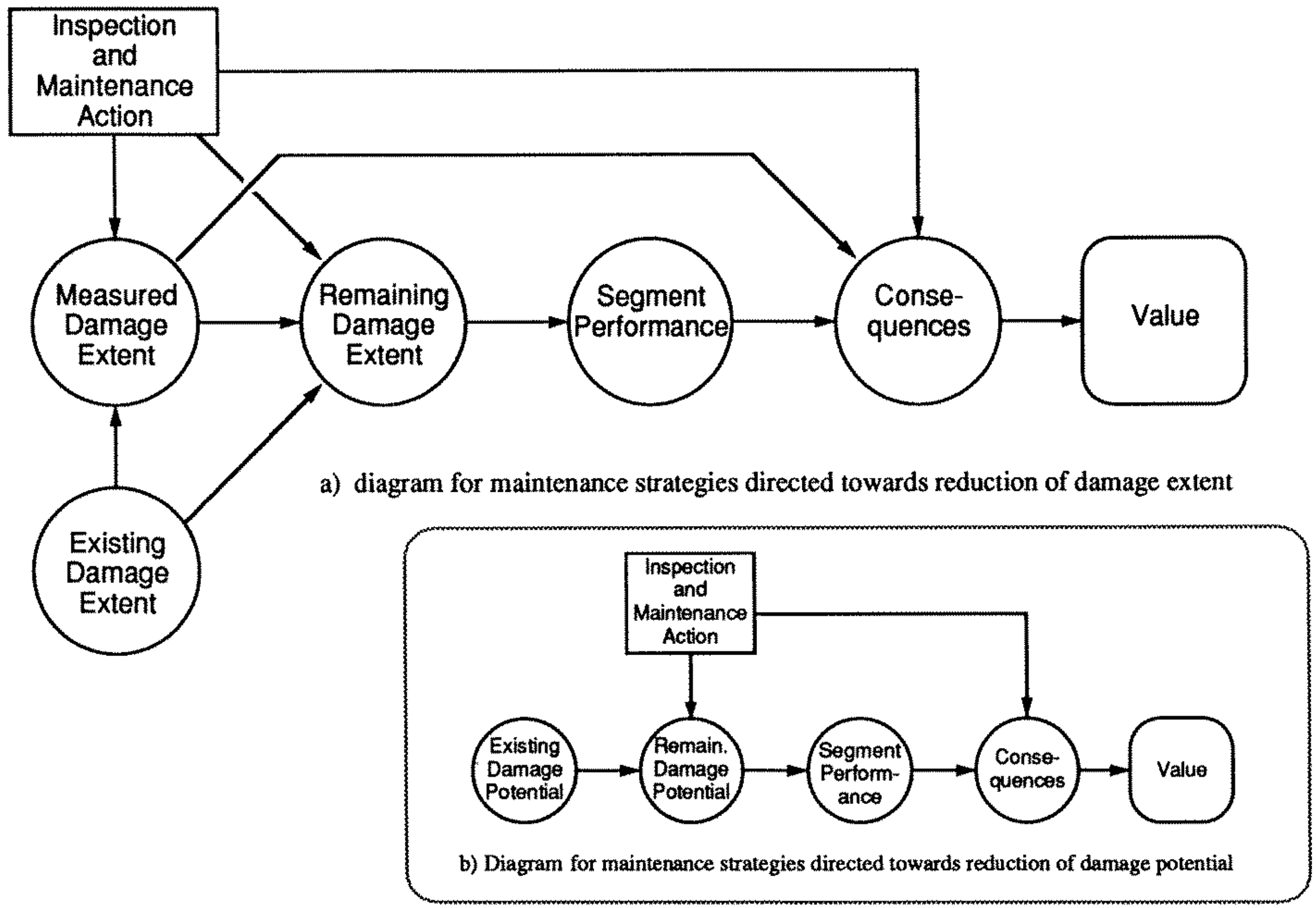


Figure 4.5 Conceptual influence diagrams for decision analysis of integrity maintenance strategies.

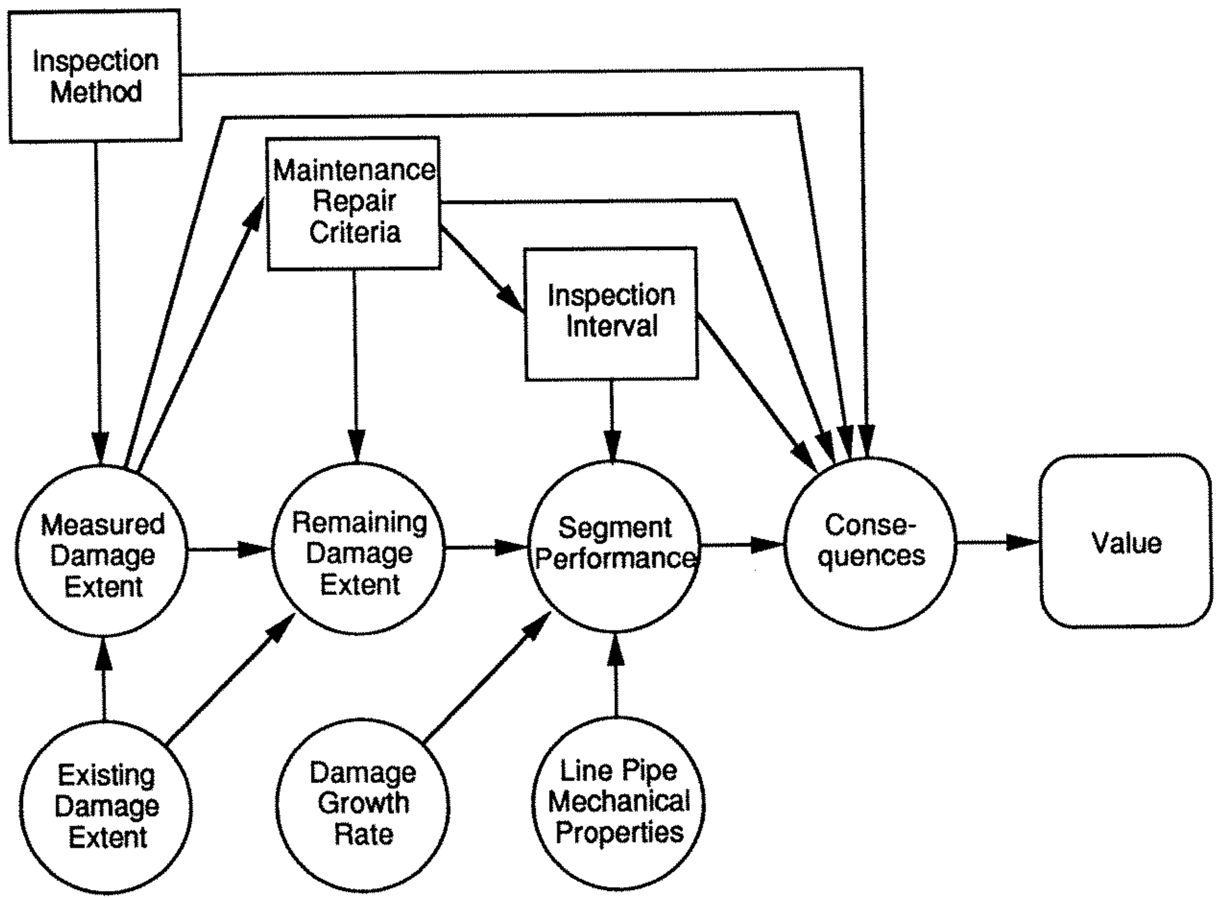


Figure 4.6 Expanded decision influence diagram for decision analysis of integrity maintenance strategies.

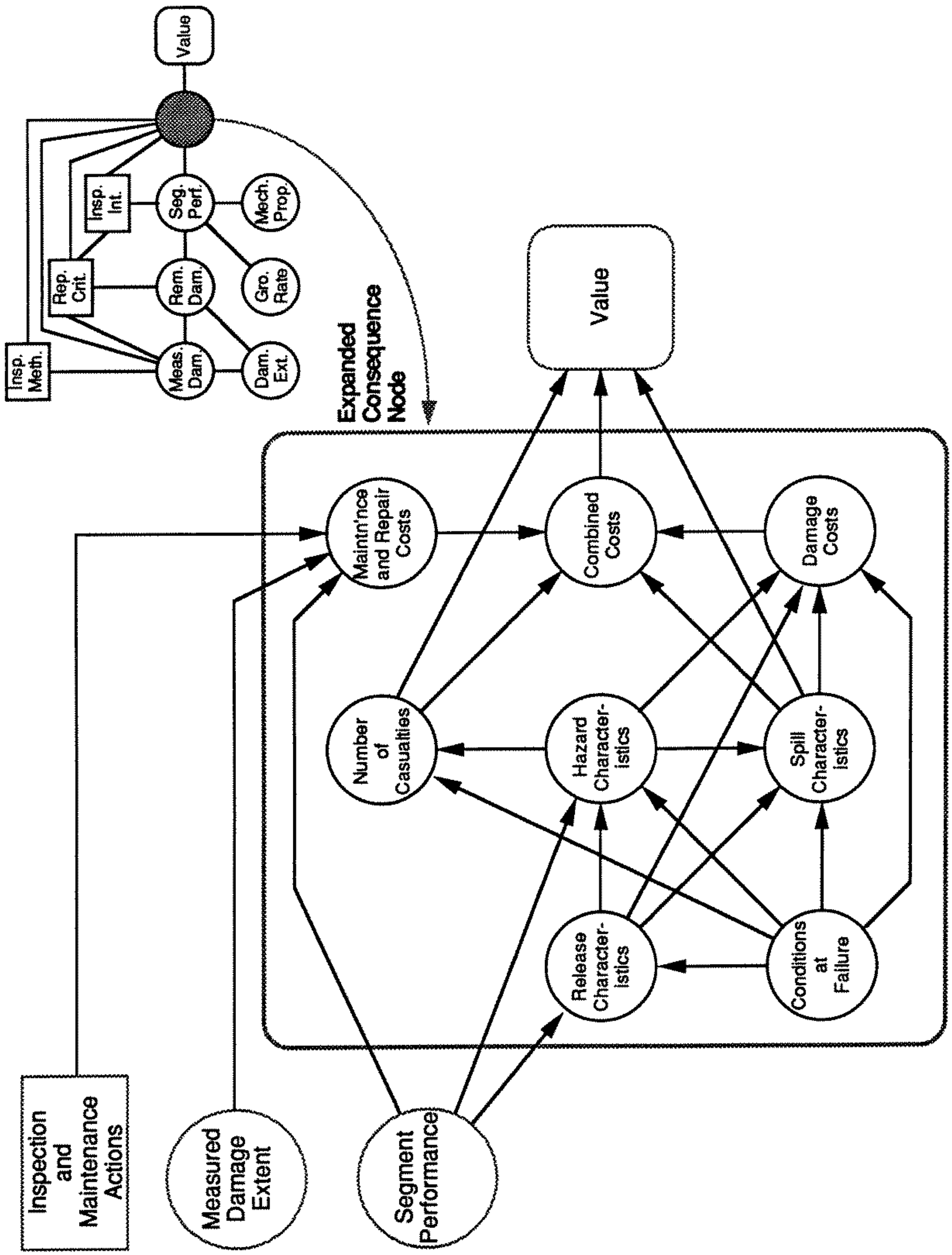


Figure 4.7 Expanded influence diagram for consequence estimation.

5.0 SUMMARY

A methodology has been developed for systematic, comprehensive, and quantitative risk analysis of buried pipelines which forms the basis for a system prioritization and integrity maintenance decision analysis framework. System prioritization is included to identify pipelines or pipeline segments within a system that present unacceptable levels of risk and/or to identify segments that would benefit the most from expenditures on risk reduction through integrity maintenance activities. Decision analysis is included to assess available integrity maintenance alternatives to determine the optimal set of inspection and maintenance activities for segments targeted at the prioritization stage.

The overall framework is intended to address all failure causes identified as potentially significant based on historical evidence, recent failure trends, and general industry concerns including: outside force (third party damage and ground movement); environmentally induced defects (mainly metal loss corrosion and stress corrosion cracking); and fabrication induced defects (specifically crack-like defects in welds). Failure hazards to be assessed include: fires (*i.e.* jet fire, pool fire, and flash fire); explosions; toxic or asphyxiating clouds; and liquid spills (for hazardous liquid lines only). The framework is also structured to provide for a comprehensive assessment of failure consequences by addressing: life safety, in terms of the number of fatalities; environmental impact, in terms of the residual spill volume adjusted to reflect the damage potential associated with the spill product and spill site; and economic aspects, in terms of the total cost of failure.

The system prioritization stage is envisioned as a software program that will process user-defined input of segment-specific attributes to provide an estimate of the failure rate for individual segments as a function of failure cause, and an estimate of the potential consequences of line failure and the associated hazards in terms of the three consequence components (*i.e.* number of casualties, environmental damage extent, and financial cost). The prioritization program will then combine the cause specific failure rates with a global measure of the loss potential associated with the different consequence components into a single measure of risk and then rank segments according to the level of risk and optionally, according to the estimated cost of risk reduction if additional user input is provided.

Summary

The proposed decision analysis stage involves a software program that implements formal decision analysis theory using influence diagrams and an automated solution algorithm to determine the optimal set of decisions for a given integrity maintenance decision analysis problem by maximizing the value all possible actions. The program will be structured to define the value associated with integrity maintenance choices using a value function based on either utility theory, in which case the resulting set of decisions will be an optimal compromise between the three different types of consequences, or based on economic consequences only where the decision set will be associated with cost optimization, potentially constrained by limits on life safety risk and/or environmental damage risk, and possibly by maintenance budget limitations.

In addition, the decision analysis program will refine the risk estimate made at the prioritization stage and also calculate the incremental cost of risk reduction associated with the optimal integrity maintenance strategy. This will facilitate a refined ranking of segments by risk level and by incremental cost of risk reduction which can form the basis for prioritizing the implementation of integrity maintenance activities.

6.0 REFERENCES

AGA 1992. An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines - June 1994 through 1990. NG-18 Report No. 200, prepared by Battelle Memorial Research Institute for the Line Pipe Research Supervisory Committee of the American Gas Association.

CAPP 1992. 1992 Oil Pipeline Performance Review. prepared by Tozer Energy Consultants Ltd. for the Canadian Association of Petroleum Producers.

Chouchaoui, B. A. and Pick, R. J. 1994. A Three Level Assessment of The Residual Strength of Corroded Line Pipe. Offshore Mechanics and Arctic Engineering — Vol. V, Pipeline Technology, 9 - 18.

CONCAWE 1993. Performance of Oil Industry Cross-Country Pipelines in Western Europe statistical summary of reported spillages - 1992. Report No. 2/93, prepared by the Oil Companies European Organization for Environmental and Health Protection, Brussels.

Concord 1993. Risk Assessment Techniques for Pipeline Systems. Prepared for the Pipeline Environmental Committee of Canadian Association of Petroleum Producers, Concord Environmental Corporation, Calgary, Alberta.

Crossthwaite, P. J., Fitzpatrick, R. D. and Hurst, N. W. 1988. "Risk assessment for the siting of developments near liquefied petroleum gas installations", Symposium Series No. 110, Institute of Chemical Engineers, 373-400.

EGIG 1993. Gas Pipeline Incidents Report 1970-1992, European Gas Pipeline Incident Data Group.

Eiber, R. J. and Bubenik, T. A. 1993. Fracture Control Plan Methodology. Eighth Symposium on Line Pipe Research, American Gas Association, Arlington, Virginia, Cat. No. L51680, 8-1 to 8-31.

Eiber, R. J., Bubenik, T. A. and Leis, B. N. 1993. Pipeline Failure Mechanisms and Characteristics of the Resulting Defects. Eighth Symposium on Line Pipe Research, American Gas Association, Arlington, Virginia, Cat. No. L51680, 7-1 to 7-19.

ERCB 1991. Pipeline Performance in Alberta. Energy Resources Conservation Board of Alberta, Calgary, Alberta.

Fearnehough, G. D. 1985. The Control of Risk in Gas Transmission Pipeline. Institute of Chemical Engineers, Symposium, No. 93, 25-44.

Fearnehough, G. D. and Corder, I. 1992. Application of Risk Analysis Techniques to the Assessment of Pipeline Routeing and Design Criteria. International Conference on Pipeline Reliability, Calgary, Alberta.

References

FEMA/DOT/EPA 1989. Handbook of Chemical Hazard Analysis Procedures. U.S. Federal Emergency Management Agency, U.S. Department of Transportation, U.S. Environmental Protection Agency, Washington, DC.

Hill, R. T. 1992. Pipeline Risk Analysis. Institution of Chemical Engineers Symposium Series, No. 130, 637-670.

Hopkins, H. F., Lewis, S. E., and Ramage, A. D. 1993. The Development and Application of the British Gas TRANSPIRE Pipeline Risk Assessment Package. Presented at the Institution of Gas Engineers, Midland Section Meeting, Loughborough, October.

Hovey, D. J. and Farmer, E. J. 1993. Pipeline Accident, Failure Probability Determined from Historical Data. Oil and Gas Journal, 91 (28), 104-107.

HSE 1989. Risk Criteria for Land Use Planning in the vicinity of Major Industrial Hazards, Health and Safety Executive, London, U.K.

Jiao, G., Sotberg, T., and Bruschi, R. 1992. Probabilistic Assessment of the Wall Thickness Requirement for Pressure Containment of Offshore Pipelines. Proceedings of the Eleventh International Conference on Offshore Mechanics and Arctic Engineering, Vol. V-A, Pipeline Technology.

Keeney. R. L. and Raiffa H. 1976. Decisions with Multiple Objectives: Preferences and Value Tradeoffs. John Wiley and Sons, New York.

Kiefner, J. F., Maxey, W. A., Eiber, R. J. and Duffy, A. R. 1973. Failure Stress Levels of Flaws in Pressurized Cylinders. Progress in Flaw Growth and Fracture Toughness Testing, ASTM STP 536, American Society for Testing and Materials, 461 - 481.

Kiefner, J. F., Vieth, P. H., Orban, J. E. and Feder, P. I. 1990. Methods for Prioritizing Pipeline Maintenance and Rehabilitation. American Gas Association.

Kulkarni, R. B. and Conroy, J. E. 1991. Development of a Pipeline Inspection and Maintenance Optimization System (Phase I). Gas Research Institute Contract No. 5091-271-2086.

Kulkarni, R. B., Conroy, J. E., Wilke, T. L., Werner, D. P., and Krauss, W. E. 1993. Inspection and Maintenance Priorities for Gas Transmission. Gas Industries, Vol. 37, No. 10, 15-17.

Lees, P. L. 1980. Loss Prevention in the Process Industries, Butterworth Group, London, U.K.

Madsen, H. O., Krenk, S. and Lind, N. C. 1986. Method of Structural Safety. Prentice-Hall Inc., Englewood Cliffs, New Jersey.

MIACC 1993. Land Use Guidelines for Pipeline Corridors (working draft), Major Industrial Accidents Council of Canada, Ottawa, Canada.

References

Morrison, T. B. and Worthingham, R. G. 1992. Reliability of High Pressure Line Pipe Under External Corrosion. Proceedings of the Eleventh International Conference on Offshore Mechanics and Arctic Engineering, Vol. V-B, Pipeline Technology.

Muhlbauer, W. K. 1992. Pipeline Risk Management Manual. Gulf Publishing Company, Houston, Texas.

Muhlbauer, W. K. 1994. Economic Considerations for Pipe Line Risk Management. Pipeline Industry, February.

Ronsky, N. D. and Trefanenko, B. 1992. Managing Pipeline Integrity: A Look at Costs and Benefits. Proceedings of the Eleventh International Conference on Offshore Mechanics and Arctic Engineering, Vol. V-B, Pipeline Technology, 299 - 306.

Shachter, R. D. 1986. Evaluating Influence Diagrams. Operations Research, Vol. 34, No. 6, November - December.

Shannon, R. W. E. and Argent, C. J. 1988. A Systems Approach to the Quantitative Condition Monitoring of Pipelines. Proceedings of the Seventeenth World Gas Conference, Washington. D. C., June.

TSB 1990. Railway/Commodity Pipeline Occurrences. Transportation Safety Board of Canada, Ottawa.

Urednicek, M., Coote, R. I., Coutts, R. 1992. Optimizing Rehabilitation Process with Risk Assessment and Inspection. Proceedings of the International Conference on Pipeline Reliability, Calgary, June, II-12-1 to II-12-14.

US DOT 1991. Annual Report on Pipeline Safety. U.S. Department of Transportation, Research and Special Program Administration, Office of Pipeline Safety, Washington, D. C.

Weber, B. J. and Mudan, K. S. 1992. Arctic Pipeline Risk Assessments. Proceedings of the Second International Offshore and Polar Engineering Conference, San Francisco, Vol. II, June, 15 - 20.

Woodward-Clyde. 1988. Forecasting Cast Iron Failure. Gas Industries, May, 10 - 17.

Zimmerman, T. J. E., Stephens, M. J., Degeer, D. D., and Chen, Q. 1994. Compressive Strain Limits for Buried Pipelines. Centre for Frontier Engineering Research, confidential Report No. 91024, June.

APPENDIX A

SUMMARY OF PIPLINE INTEGRITY ISSUES

A.1 Introduction

The level of integrity or the reliability of buried pipeline systems depends on the probability of line failure which is influenced by the causative mechanisms that are active, the damage extent or damage potential associated with each active failure cause, as well as the inspection and maintenance actions that are taken to reduce the probability of line failure. Section A.2 contains a summary, by failure cause, of significant factors contributing to pipeline damage extent and/or damage potential, inspection methods available to detect damage, and maintenance alternatives available to prevent or repair damage prior to pipeline failure. Also included in the summary is a list of key parameters that are taken into account in the damage assessment models that are currently employed to decide when remedial maintenance repair action is required. The summary information is based on a review of literature in the field of pipeline integrity maintenance. Primary reference sources are given in the bibliography included in Section A.3.

A.2.1 Mechanical Damage

Contributing Factors

- land use (i.e. level of activity)
- depth of cover
- right-of-way patrol frequency
- one-call system implementation
- level of public consultation
- extent of signage
- right-of-way condition
- presence of subsurface markers
- presence of mechanical protection

Supporting Evidence

- historical evidence of mechanical damage
- history of mechanical damage failures

Inspection Methods

- right-of-way patrol in conjunction with confirmation excavations
- coating damage survey and/or cathodic protection survey in conjunction with confirmation excavations
- in-line inspection using low or high resolution magnetic flux leakage tool in conjunction with confirmation excavations
- in-line inspection using low resolution geometry tool in conjunction with confirmation excavations
- in-line inspection using high resolution pipe position/geometry tool
- in-line inspection using ultrasonic wall thickness tool
- hydrostatic testing

Proactive Maintenance Alternatives

Preventative actions (for future damage):

- enhance public awareness
- improve right-of-way condition
- add signage
- increase right-of-way patrol frequency
- install subsurface marker tape
- install mechanical protection (i.e. steel plate or concrete slab)
- increase burial depth

Remedial actions (for existing damage):

- grind surface gouge(s) if present and perform local coating repair(s)
- grind surface gouge(s) if present and install full encirclement sleeve(s)
- perform cut-out replacement(s)
- perform hydrostatic test and required repairs to remove critical defects

Parameters Associated with Damage Assessment Model

- dent depth
- gouge length and effective depth
- pipe diameter and wall thickness
- operating pressure level
- pipe body yield strength and notch toughness

A.2.2 Ground Movement

Contributing Factors

- ground movement mechanism
  (e.g. slope instability, thaw settlement, frost heave, subsidence)
- ground movement potential/extent
- depth of cover
- soil type
- soil load-deformation response
- pipe diameter
- pipe axial and bending stiffness

Supporting Evidence

- evidence of ground movement
- history of ground movement induced failures

Inspection Methods

- right-of-way patrol
- ground movement survey
- pipe movement survey
- in-line inspection using high resolution pipe position/geometry tool

Proactive Maintenance Alternatives

Preventative actions (for future damage):

- control ground movement potential (stabilize slope, insulate pipe)
- isolate pipe from ground movement (expose pipe, use special backfill)

Remedial actions (for existing damage):

- perform cut-out replacement(s)
- carry out multi-joint pipe replacement
- deactivate, abandon & reroute segment

Parameters Associated with Damage Assessment Model

Compressive strain controlling:

- induced longitudinal compressive strain level
- pipe diameter-to-thickness ratio
- internal pressure level
- pipe body material stress-strain response (i.e. hardening modulus)

Tensile strain controlling:

- induced longitudinal tensile strain level
- degree of girth-weld-to-pipe-body strength overmatch
- girth weld metal stress-strain response
- weld metal and HAZ toughness
- permissible girth weld defect size and level of construction inspection

A.2.3 External Metal Loss Corrosion

Contributing Factors

- soil type and corrosivity
- ground water chemistry and drainage characteristics
- coating type and condition
- level of coating inspection during construction
- ground movement mechanism and movement extent as it affects coating condition
- cathodic protection system condition
  (i.e. pipe-to-soil potential level, uniformity of protection, current demand changes)
- presence of electrical interference
- presence of cased crossings
- operating temperature
- segment age
- line pipe manufacturer and manufacturing process

Supporting Evidence

- historical evidence of external corrosion damage
- history of external corrosion failures

Inspection Methods

- bell hole excavations at locations targeted by site susceptibility models
- coating damage survey and/or cathodic protection survey
  in conjunction with confirmation excavations
- in-line inspection using low-resolution magnetic flux leakage tool
  or ultrasonic wall thickness tool in conjunction with confirmation excavations
- in-line inspection using high-resolution magnetic flux leakage tool
- hydrostatic testing

Proactive Maintenance Alternatives

- enhance cathodic protection level
- perform local coating repair(s)
- carry out multi-joint coating rehabilitation
- install full encirclement sleeve(s)
- perform cut-out replacement(s)
- carry out multi-joint pipe replacement
- perform hydrostatic test and required repairs to remove critical defects
- lower operating pressure
- deactivate, abandon & reroute segment

Parameters Associated with Defect Assessment Model

- corrosion defect length and effective depth
- pipe diameter and wall thickness
- operating stress level
- pipe body yield strength

A.2.4 Internal Metal Loss Corrosion

Contributing Factors

- product corrosivity
- product impurities (e.g. H_2O, SO_2, CO_2)
- product abrasion potential
- micro biological action
- pipe body & weld metal composition
- operating temperature
- segment geometry
- flow rate
- segment age
- use of corrosion inhibitors
- presence of internal coating
- internal coating condition

Supporting Evidence

- historical evidence of internal corrosion damage
- history of internal corrosion failures

Inspection Methods

- bell hole excavations and ultrasonic/gammagraphic inspection at locations targeted by site susceptibility models
- in-line inspection using low-resolution magnetic flux leakage tool or ultrasonic wall thickness tool in conjunction with confirmation excavations and ultrasonic/gammagraphic inspection
- in-line inspection using high-resolution magnetic flux leakage tool
- hydrostatic testing

Proactive Maintenance Alternatives

- remove corrosive material from line by scraping or pigging
- filter corrosive impurities
- add corrosion inhibitor
- introduce internal coating agent
- install full encirclement sleeve(s)
- perform cut-out replacement(s)
- carry out multi-joint pipe replacement
- perform hydrostatic test and required repairs to remove critical defects
- lower operating pressure
- deactivate, abandon & reroute segment

Parameters Associated with Defect Assessment Model

- corrosion defect length and effective depth
- pipe diameter and wall thickness
- operating stress level
- pipe body yield strength

A.2.5 Stress Corrosion Cracking

Contributing Factors

- soil type and corrosivity
- ground water chemistry and drainage characteristics
- operating stress history (static stress level & cyclic stress range)
- operating temperature
- coating type
- coating condition
  (construction & inspection practice, soil stress, operating temperature, age)
- cathodic protection system condition
  (current level, uniformity of protection, current demand changes)
- segment age
- pipe manufacturer and manufacturing process
- pipe body & weld metal composition

Supporting Evidence

- history of increasing cathodic protection current demand
- historical evidence of SCC damage
- history of SCC failures

Inspection Methods

- bell hole excavations at locations targeted by site susceptibility models
- coating damage survey and/or cathodic protection survey
  in conjunction with confirmation excavations
- *in-line inspection using high-resolution crack detection tool (future technology)*
- hydrostatic testing

Proactive Maintenance Alternatives

- adjust cathodic protection level
- grind surface cracks and perform local coating repair(s)
- grind surface cracks and install full encirclement sleeve(s)
- perform cut-out replacement(s)
- carry out multi-joint pipe replacement
- perform hydrostatic test and required repairs to remove critical defects
- lower operating pressure
- deactivate, abandon & reroute segment

Parameters Associated with Defect Assessment Model

- SCC defect length and effective depth
- pipe diameter and wall thickness
- operating stress level
- pipe body yield strength and notch toughness

A.2.6 Crack-like Weld Defects

Contributing Factors

- line pipe manufacturing process
- line pipe manufacturer
- line pipe transportation method
- operating stress history (static stress level & cyclic stress range)
- segment age
- girth weld process
- level of field weld inspection
- lack of initial hydrotest

Inspection Methods

- in-line inspection using high-resolution magnetic flux leakage tool
- *in-line inspection using high-resolution crack detection tool (future technology)*
- hydrostatic testing

Proactive Maintenance Alternatives

- perform cut-out replacement(s)
- perform hydrostatic test and required repairs to remove critical defects
- lower operating pressure
- deactivate, abandon & reroute segment

Parameters Associated with Defect Assessment Model

- defect length and effective depth
- pipe diameter and wall thickness
- operating stress level
- pipe body yield strength and notch toughness

A.3 Bibliography

Allen, M. D. and Barnes, N. R. 1987. Specialised Corrosion Surveys for Buried Pipelines: Methods and Experience. Paper first presented at the Seventh International Conference on the Internal and External Protection of Pipes, organized and sponsored by BHRA, The Fluid Engineering Centre, London, England.

Beavers, J. A. 1993. On the Mechanism of Stress Corrosion Cracking of Natural Gas Pipelines. Eighth Symposium on Line Pipe Research, American Gas Association, Arlington, Virginia, 17-1 to 17-11.

Beller, M., Germerdonk, K., Mattheck, C., Munz, D. and Schneider, U. 1991. On the Problem of Detecting and Assessing Cracks in Pipelines. Proceedings of the Tenth International Conference on Offshore Mechanics and Arctic Engineering, Vol. V, Pipeline Technology, 169 - 173.

Borek, H. and Leeds, J. M. 1988. A Practical Comparison of Above Ground Techniques for Coating Defect Delineation. Industrial Corrosion, March/April, 14 - 21.

Carlson, R. E. Jr. 1993. Internal Pipeline Corrosion Coatings: Case Studies and Solutions Implemented. Proceedings of the Twelfth International Conference on Offshore Mechanics and Arctic Engineering, Vol. V, Pipeline Technology, 241 - 245.

Chatain, R. 1993. An Experimental Evaluation of Punctures and Resulting Dents in Transmission Pipelines. Eighth Symposium on Line Pipe Research, American Gas Association, Arlington, Virginia, 11-1 to 11-12.

Chouchaoui, B. A. and Pick, R. J. 1994. A Three Level Assessment of The Residual Strength of Corroded Line Pipe. Proceedings of the Thirteenth International Conference on Offshore Mechanics and Arctic Engineering, Vol. V, Pipeline Technology, 9 - 18.

Coates, A. C. and Thomas, E. B. 1993. Aging of Pipelines: Risk Assessment, Rehabilitation and Repair. Proceedings of the Twelfth International Conference on Offshore Mechanics and Arctic Engineering, Vol. V, Pipeline Technology, 195 - 201.

Gwartney, W. R. 1989. Pipeline Internal Monitoring Techniques Now and the Future. Eighth International Conference on Offshore Mechanics and Arctic Engineering, The Hague, 253 - 256.

Harvey, D. W. 1994. Maintaining Integrity on Buried Pipelines. Materials Performance, August, 22 - 27.

Hopkins, P. Corder, I and Corbin, P. 1992. The Resistance of Gas Transmission Pipelines to Mechanical Damage. Proceedings of the CANMET International Conference on Pipeline Reliability, Calgary, June, VIII-3-1 to VIII-3-18.

Jones, D. G. and Hopkins, P. 1991. Methodologies for the Assessment of Defects in Offshore Pipelines and Risers. Proceedings of the Tenth International Conference on Offshore Mechanics and Arctic Engineering, Vol. V, Pipeline Technology, 113 - 118.

Kiefner, J. F., Hyatt, R. W. and Eiber, R. J. 1989. Tools Locate, Measure Dents and Metal Loss. Technology, Oil & Gas Journal, April 17, 30 - 38.

Kiefner, J. F., Hyatt, R. W. and Eiber, R. J. 1989. Metal-Loss, Crack-Detection Tools Targeted. Technology, Oil & Gas Journal, April 24, 69 - 71.

Kiefner, J. F., Maxey, W. A., Eiber, R. J. and Duffy, A. R. 1973. Failure Stress Levels of Flaws in Pressurized Cylinders. Progress in Flaw Growth and Fracture Toughness Testing, ASTM STP 536, American Society for Testing and Materials, 461 - 481.

Kiefner, J. F., Vieth, P. H., Orban, J. E. and Feder, P. I. 1990. Methods for Prioritizing Pipeline Maintenance and Rehabilitation. Final Report on Project PR3-919 to the American Gas Association.

Kulkarni, R. B. and Conroy, J. E. 1991. Development of a Pipeline Inspection and Maintenance Optimization System (Phase I). Gas Research Institute Contract No. 5091-271-2086.

Kulkarni, R. B. and Conroy, J. E. 1993. Inspection and Maintenance Priorities for Gas Transmission. Gas Industries, Vol. 37, No. 10, 15 - 17.

Leis, B. N. and Brust, F. W. 1989. Flaw Growth and Implications for Line Pipe Serviceability Assessed by Hydrotesting. Eighth International Conference on Offshore Mechanics and Arctic Engineering, The Hague, 285 - 292.

Leis, B. N. and Brust, F. W. 1992. Hydrotest Strategies for Gas Transmission Pipelines Based on Ductile-Flaw-Growth Considerations. Topical Report presented to the American Gs Association, NG-18 Report No. 194, SI Task 1.10-89, July.

Maxey, W. A., Vieth, P. H. and Kiefner, J. F. 1993. An Enhanced Model for Predicting Pipeline Retest Intervals to Control Cyclic-Pressure-Induced Crack Growth. Proceedings of the Twelfth International Conference on Offshore Mechanics and Arctic Engineering, Vol. V, Pipeline Technology, 353 - 357.

Mayer, G. R., van Dyke, H. J. and Myrick, C. E. 1987. Risk Analysis Determines Priorities Among Pipeline-Replacement Projects. Technology, Oil & Gas Journal, September 21, 100 - 106.

Moore, V. A. 1987. Practical Use of Liquid Coating, Wrapping Tapes and Cathodic Protection for Corrosion Protection. Paper first presented at the Seventh International Conference on the Internal and External Protection of Pipes, organized and sponsored by BHRA, The Fluid Engineering Centre, London, England.

Morrison, T. B. and Worthingham, R. G. 1992. Reliability of High Pressure Line Pipe Under External Corrosion. Proceedings of the Eleventh International Conference on Offshore Mechanics and Arctic Engineering, Vol. V-B, Pipeline Technology.

Appendix A

Muhlbauer, W. K. 1992. Pipeline Risk Management Manual. Gulf Publishing Company, Houston, Texas.

Parkins, R. N. 1994. Stress Corrosion Cracking in Pipelines. Proceedings of the 1994 NACE International - Canadian Region Western Conference, National Association of Corrosion Engineers, February.

Ronsky, N. D. and Trefanenko, B. 1992. Managing Pipeline Integrity: A Look at Costs and Benefits. Proceedings of the Eleventh International Conference on Offshore Mechanics and Arctic Engineering, Vol. V-B, Pipeline Technology, 299 - 306.

Stephens, D. R. and Bubenik, T. A. 1993. Development of Guidelines for Acceptance of Corroded Pipe. Eighth Symposium on Line Pipe Research, American Gas Association, Arlington, Virginia, 25-1 to 25-13.

Taylor, S. A. 1994. Worldwide Rehabilitation Work is Undergoing Major Changes. Pipe Line Industry, February, 25 - 31.

Trigg, A. and Rizkalla, M. 1994. Development and Application of a Closed Form Technique for the Preliminary Assessment of Pipeline Integrity in Unstable Slopes. Proceedings of the Thirteenth International Conference on Offshore mechanics and Arctic Engineering, Vol. V, Pipeline Technology, 127-139.

Urednicek, M., Coote, R. I. and Coutts, R. 1992. Optimizing Rehabilitation Process with Risk Assessment and Inspection. Proceedings of the CANMET International Conference on Pipeline Reliability, Calgary, June, II-12-1 to II-12-14.

Urednicek, M., Lambert, S. Vosikovsky, O. 1992. Stress Corrosion Cracking (SCC) - Monitoring and Control. Proceedings of the CANMET International Conference on Pipeline Reliability, Calgary, June, VII-2-1 to VII-2-19.

Zimmerman, T. J. E., Stephens, M. J., Degeer, D. D., and Chen, Q. 1994. Compressive Strain Limits for Buried Pipelines. Centre for Frontier Engineering Research, confidential Report No. 91024, June.

APPENDIX B

REVIEW OF PIPELINE INCIDENT DATA BASES

B.1 Overview

Pipeline failure incident data bases and/or statistical summary reports based on these data bases were reviewed, with an emphasis on assessing the type and quantity of information available, the consistency in incident reporting criteria and the potential to extract meaningful failure rate estimates for pipelines having specific attribute combinations. A summary of the contents of each of the data bases that were reviewed is given in Section B.2 and a critical assessment of the information contained in the publicly assessable data bases is given in Section B.3. A listing of the data bases and statistical reports reviewed is included if Section B.4.

B.2 Data Bases and Associated Summary Reports

B.2.1 Pipelines in Alberta

B.2.1.1 Energy Resources Conservation Board (ERCB)

Description - The ERCB is the Alberta government regulatory authority responsible for all energy-related intraprovincial pipelines. There are currently approximately 220 000 km of pipeline under ERCB jurisdiction including: 133 000 km of natural gas pipeline; 27 600 km of crude oil pipeline; and 2 300 km of 'other' pipeline (which includes refined liquid products). Records of reported pipeline failures have been kept by the ERCB since 1975.

Reporting Criteria - The current ERCB reporting criteria involves mandatory reporting of all pipeline failures resulting in product release 'without limitation of cause, magnitude or consequence'.

Report Format - Current failure incident report form is shown in Figure B1.

Appendix B

Form and Availability of Incident Data - Failure incident data is maintained in a computerized data base that is publicly available.

Summary Reports Based on Data -

- Pipeline Performance in Alberta (ERCB 1991) - A statistical summary of pipeline system performance for the 1980 - 1990 operating period compiled by the ERCB. Information includes:
  - number of failures per year by cause for each type of pipeline (i.e. natural gas, sour gas, crude oil, multiphase, and produced water)
  - failure rates (i.e. number of failures per km yr) for each type of pipeline
  - number of leaks vs. number of ruptures including cause breakdown
  - estimated spill volumes for liquid product releases (i.e. crude oil, multiphase and water)

  Summary updated in 1993 to include the 1991 - 92 operating period (Cassley *et al.* 1994).

B.2.2 Pipelines in Canada

B.2.2.1 National Energy Board (NEB)

Description - The NEB is the Canadian government regulatory authority responsible for all hydrocarbon pipelines crossing provincial or international boarders. There are currently approximately 36 000 km of pipeline under NEB jurisdiction including: 19 100 km of natural gas pipeline; 12 500 km of crude oil pipeline; and 4 km of 'other commodity' pipeline (which includes refined liquid products). Records of reported pipeline failures have been kept by the NEB since 1950, however, detailed incident reporting was not instituted until the 1970's.

Reporting Criteria - The current NEB reporting criteria involves mandatory reporting of all incidents relating to the construction, operation or abandonment of a pipeline that result in at least one of the following: uncontained spillage of oil in excess of 1.5 m^3; uncontrolled escape of gas or HVP product; death of a person or injury to a person requiring hospitalization; explosion or ignition of gas or HVP product; discharge of toxic substances onto land or into water; or interruption of pipeline operation.

Appendix B

Report Format - Currently there is no standard failure incident report form. The failure incident data is entered by NEB personnel based on the incident report filed by the operator, which must satisfy general reporting guidelines defined in the Onshore Pipeline Regulations. The information requirements are in general similar to those of the ERCB.

Form and Availability of Incident Data - Failure incident data is maintained in a computerized data base that is publicly available.

Summary Reports Based on Data -

- Annual Reports of the National Energy Board (e.g. NEB 1992) - A brief statistical summary of pipeline system performance for the most recent five year period compiled by the NEB. Information includes:
  - number of failure incidents per year broken down by failure cause

B.2.2.2 Transportation Safety Board (TSB)

Description - The TSB is a Canadian government agency established in 1990 to advance the transportation safety of commodity pipelines and other transport modes by, among other activities, conducting independent investigations and collecting and maintaining incident and accident data. The TSB assumed the accident investigation and data collection role for pipelines under NEB jurisdiction in March, 1990 (see NEB data base summary for length of system).

Reporting Criteria - The current TSB reporting criteria distinguishes between pipeline accidents and pipeline incidents. A reportable accident involves: pipeline damage resulting in product release; a pipeline explosion, ignition or fire not associated with normal operation, pipeline damage affecting safe operation caused by outside force (i.e. mechanical damage or ground movement); or death or injury to a person (due to pipeline fire, ignition, explosion or product release). A reportable incident involves: uncontained or uncontrolled product release, pipeline operation beyond design limits, pipeline movement causing obstruction; abnormalities that reduce the line integrity below design limits; activities in the immediate vicinity that pose a threat to line integrity; or emergency shut-downs.

Report Format - Currently there is no standard failure incident/accident report form. The failure incident data is entered by TSB personnel based on the incident report filed by the operator, which must satisfy general reporting guidelines defined in the TSB Regulations. The information requirements are in general similar to those of the NEB.

Form and Availability of Incident Data - Failure incident data is maintained in a computerized data base that is not publicly available.

Summary Reports Based on Data -

- Annual TSB Statistical Summary - Commodity Pipeline Occurrences (e.g. TSB 1992) - A statistical summary of pipeline system performance for the most recent ten year period compiled by the TSB (including data compiled by the NEB prior to 1990). Information includes:
  - number of accidents and incidents per year broken down by: province; facility type; cause; and product transported

B.2.2.3 Canadian Association of Petroleum Producers (CAPP)

Description - CAPP is an industry association of hydrocarbon production companies formed in 1992 following the merger of the Canadian Petroleum Association (CPA) and the Independent Petroleum Association of Canada (IPAC). CAPP maintains a data base on the performance of Canadian oil pipelines and HVP product pipelines downstream of production facilities and refined petroleum product lines. The combined length of downstream hydrocarbon product pipeline represented in the CAPP data is approximately 32 800 km which represents the majority of the industry (25 operating companies) and all of the major oil pipeline systems in Canada.

Reporting Criteria - The current CAPP reporting criteria involves voluntary reporting of all incidents resulting in a spill of 1.5 m^3 or more of liquid hydrocarbon, or any amount of HVP product, and any incident involving death or injury to a person, fire or explosion.

Appendix B

Report Format - The current CAPP failure incident report form is shown in Figure B2.

Form and Availability of Incident Data - Failure incident data is maintained in a computerized data base that is not publicly available.

Summary Reports Based on Data -

- Annual Oil Pipeline Performance Review (e.g. CAPP 1992) - A statistical summary of oil pipeline system performance for the reporting year together with a summary for the performance in the preceding ten year period compiled for CAPP by an independent consultant. Information includes:
  - number of failures in reporting year broken down by cause, facility type and product (i.e. LVP and HVP)
  - number of failures per year by cause for the preceding ten year period
  - estimated spill volumes (and recovered volumes) for liquid product releases in the reporting year broken down by failure cause
  - failure rates (i.e. number of failures per km yr) for the reporting year and the preceding ten year period
  - number of deaths, number of injuries, total spill volume, and total accident costs for the reporting year and the preceding ten year period

B.2.3 Pipelines in the United States

B.2.3.1 United States Department of Transportation (USDOT)

Description - The USDOT is the American government regulatory authority responsible for gas and hazardous liquid pipelines including both intrastate and interstate lines. There are currently approximately 2 700 000 km of gas pipeline under DOT jurisdiction including: 474 000 km of onshore gathering and transmission pipeline and 18 000 km of offshore gathering and transmission pipeline. The DOT also regulates approximately 354 000 km of hazardous liquid pipeline which includes LVP and HVP liquids as well as refined products. Records of reported pipeline failures have been maintained by the USDOT since 1968 for liquid pipelines and since 1970 for gas lines.

Reporting Criteria - The current USDOT reporting criteria for natural gas pipelines involves mandatory reporting of all incidents that involve release of gas from a pipeline <u>and</u> fatality or personal injury requiring hospitalization or estimated property damage (including lost product cost) of $50 000 or more. The current reporting criteria for hazardous liquid pipelines requires reporting of all incidents that involve the loss of ~8.0 m^3 or more of liquid or ~0.8 m^3 of HVP product, explosion or fire, death or bodily harm to a person or estimated property damage exceeding $5 000.

Report Format - The current USDOT failure incident report form is shown in Figures B3 and B4 for gas transmission and gathering lines and hazardous liquid pipelines respectively.

Form and Availability of Incident Data - Failure incident data is maintained in a computerized data base that is publicly available.

Summary Reports Based on Data -

- Annual Report on Pipeline Safety (e.g. USDOT 1991) - A brief statistical summary of pipeline system performance for the reporting year and the most recent five year period compiled by the DOT. Information includes:
  - number of incidents per year broken down by failure cause and pipeline type (i.e. gas transmission & gathering, gas distribution, and hazardous liquid)
  - estimated spill volumes for liquid product releases in the reporting year broken down by failure cause

- An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines - June 1984 through 1990 (AGA 1992) - A detailed statistical summary of onshore and offshore gas transmission and gathering line performance for a 6 1/2 year period compiled by Battelle for the American Gas Association. Information includes:
  - number of incidents per year broken down by: system type (onshore vs. offshore); failure cause; pipe material & failed component; presence of marking & prior notification; and failure type (leak vs. rupture)
  - number of incidents per year causing fatalities & injuries by failure cause and system type
  - failure rate (i.e. number of failures per km yr) by line diameter

  A similar summary report covering the 1970 to June 1984 period (when the incident reporting criteria changed) is also available (AGA 1986).

- Trends in the Incidence and Cost of Liquid Pipeline Accidents from 1982 to 1990 (Hovey and Farmer 1992) - A statistical summary of hazardous liquid pipeline performance for a ten year period compiled by EFA Technologies Inc. from USDOT incident data (USDOT 1992). Information includes:

- number of failures per year broken down by failure cause
- total volume of product lost per year
- total and average property damage cost per year

- Pipeline Accident, Failure Probability Determined from Historical Data (Hovey and Farmer 1993) - A statistical summary of hazardous liquid pipeline performance for a ten year period compiled by EFA Technologies Inc. from a USDOT incident data (USDOT 1992) and estimates of the total length of liquid line under DOT regulation. Information includes:
    - failure rate (i.e. number of failures per km yr) broken down by failure cause

B.2.4 Pipelines in Western Europe

B.2.4.1 European Gas Pipeline Incident Data Group (EGIG)

Description - The EGIG is a group of eight Western European gas transmission companies that have collaborated in the collection and maintenance of pipeline incident data. The total length of gas transmission pipeline reflected in the EGIG data is currently about 93 000 km. The incident data has been collected by most of the participating companies since about 1970.

Reporting Criteria - The current EGIG reporting criteria involves voluntary reporting of all incidents resulting in an unintentional release of gas (excluding facilities, valves and other mechanical components, and pipelines operating at less than 1520 kPa).

Report Format - The incident reporting format is not known, however, it is noted that unlike other data bases the EGIG incident reports include a leak size estimate based on three size categories: pinhole/crack (defect diameter less than 20 mm), hole (defect diameter greater than 20 mm but not exceeding pipe diameter), and rupture (defect diameter exceeding pipe diameter).

Form and Availability of Incident Data - Failure incident data is maintained in a proprietary data base.

Summary Reports Based on Data -

- Gas Pipeline Incidents report 1970-1992 (EGIG 1993) - A statistical summary of gas transmission pipeline system performance for the 22 year period ending in 1992 compiled by the EGIG. Information includes:
    - failure rates (i.e. number of failures per km yr) for each leak size broken down by failure cause
    - for outside force damage, failure rates for each leak size broken down by line diameter, line wall thickness, and depth of cover,
    - for construction and material defects, failure rates for each leak size broken down by year of construction
    - for corrosion damage, failure rates for each leak size broken down by wall thickness and year of construction

B.2.4.2 Oil Companies European Organization for Environmental and Health Protection (CONCAWE)

Description - CONCAWE is an association of 66 Western European oil pipeline operating companies that have collaborated in the collection and maintenance of pipeline incident data. The combined length of cross-country oil pipeline reflected in the CONCAWE data is currently about 21 500 km. The incident data has been collected by most of the participating companies since about 1971.

Reporting Criteria - The current CONCAWE reporting criteria involves voluntary reporting of all incidents resulting in a spillage of 1.0 m^3 or more, or of lesser amounts if their impact on the environment is deemed significant..

Report Format - The incident reporting format is not known.

Form and Availability of Incident Data - Failure incident data is maintained in a proprietary data base.

Appendix B

Summary Reports Based on Data -

- Performance of Oil Industry Cross-Country Pipelines in Western Europe statistical summary of reported spillages - 1992 (CONCAWE 1993) - A statistical summary of oil pipeline system performance for the reporting year and selective summaries for the five year and 21 year period ending in 1992 compiled by the CONCAWE. Information includes:
  - number of incidents and spill volumes (gross and net) per year broken down by failure cause for one year, five year and 21 year periods
  - failure rate information (i.e. number of failures per km yr) broken down by failure cause for the most recent five year period

A.3 Assessment of Information Contained in Incident Data Bases

A review of the available data base report forms suggests that the current structure of requested information is similar (though not identical) in all significant areas. A list of information that is typically requested and stored includes (but is not limited to) the following:

- operator information and pipeline identification
- failure time and location
- failure cause
- failure type (leak vs. rupture, occurrence of explosion, ignition or fire)
- life safety consequences (deaths or injuries)
- operating conditions (pressure at failure, maximum operating pressure)
- pipeline parameters (pipe size, pipe type, material grade, coating type, use of cathodic protection, burial depth)
- type of product and estimate of volume released (and recovered where applicable)
- liquid spill particulars (spill extent, terrain affected, rehabilitation. required, etc.)

In comparing data bases significant differences were noted in what constitutes a reportable incident. Reporting criteria ranges from the reporting of any product release (e.g. ERCB) to the reporting only of releases involving death or injury or property damage in excess of $50,000 (USDOT for gas lines). This suggests the potential for large discrepancies in estimates of the number of incidents associated with small leaks. While this type of incident does not generally pose a significant threat to public safety and/or the environment small leaks potentially constitute a significant component of the total operating cost for a pipeline system.

With regard to the general information structure of publicly available data bases and the potential to extract meaningful failure rate estimates by specific pipeline attribute combinations, the review suggests that the reported number of incidents per year can usually be correlated to corresponding pipeline system length estimates to permit calculation of overall failure rates (i.e. number of failures per km yr), however, in many cases it is not readily apparent whether or not the length of pipeline associated with particular attribute combinations can be readily obtained. Without this attribute specific line length information a detailed break down of failure rates by specific attribute combinations may not be possible.

B.4 Bibliography

ERCB 1991. Pipeline Performance in Alberta. Energy Resources Conservation Board of Alberta, Calgary, Alberta.

Cassley, A. , Larson, A., and Johnson, A. 1994. "Pipeline Performance in Alberta", proceedings of the 1994 NACE International - Canadian Region Western Conference, National Association of Corrosion Engineers, February.

NEB 1992. Annual Report of the National Energy Board. National Energy Board.

TSB 1993. TSB Statistical Summary - Commodity Pipeline Occurrences 1993. Transportation Safety Board or Canada.

CAPP 1992. 1992 Oil Pipeline Performance Review. prepared by Tozer Energy Consultants Ltd. for the Canadian Association of Petroleum Producers.

USDOT 1991. Annual Report on Pipeline Safety - Calendar Year 1991. Research and Special Programs Administration of the U. S. Department of Transportation

USDOT 1992. 1982-1991 Liquid Pipeline Accident Report. Research and Special Programs Administration of the U. S. Department of Transportation

AGA 1992. An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines - June 1994 through 1990. NG-18 Report No. 200, prepared by Battelle Memorial Research Institute for the Line Pipe Research Supervisory Committee of the American Gas Association.

AGA 1986. An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines - 1970 through June 1984. NG-18 Report No. 158, prepared by Battelle Memorial Research Institute for the Line Pipe Research Supervisory Committee of the American Gas Association.

Hovey, D. J., and Farmer, E. J. 1992. Trends in the Incidence and Cost of Liquid Pipeline Accidents from 1982 to 1991. Ed Farmer & Associates, Inc. Sacramento, CA.

Appendix B

Hovey, D. J., and Farmer, E. J. 1993. Pipeline Accident, Failure Probability Determined from Historical Data. Oil and Gas Journal, 91 (28), 104-107.

EGIG 1993. Gas Pipeline Incidents Report 1970-1992. A report of the European Gas Pipeline Incident Group.

CONCAWE 1993. Performance of Oil Industry Cross-Country Pipelines in Western Europe statistical summary of reported spillages - 1992. Report No. 2/93, prepared by the Oil Companies European Organization for Environmental and Health Protection.

Payne, B. L. 1993. California Hazardous-Liquid Pipeline Risk Assessment. proceedings of the 4th annual Pipeline Risk Assessment, Rehabilitation and Repair Conference. Houston, TX.

CSFM 1993. Hazardous Liquid Pipeline Risk Assessment. prepared for the California State Fire Marshal by EDM Services, Inc. Simi Valley, CA.

Figures

ERCB
Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alta. T2P 3G4

POLLUTION/BREAK RECORD

A.C.D CODE 80

LOCATION OF SOURCE: LE | LS | SC | TWP | RG | W | M (11, 12)
EVENT (13 14) | CARD 0 8 0 (15 17) | DATE/TIME OF OCCURRENCE: YR. | MO. | DAY | HR | MIN (18 23) | DATE TIME REPORT RECEIVED: YR | MO | DAY | HR | MIN | COMPLAINT (24) | REPORT (25)

SOURCE/CAUSE (26 29) | INJURY (30) | DEATH (31)

AREA OFFICE (32 33) | FOREST DISTRICT (34 35) | FIELD OR AREA (36 39)

COMPLAINANT OR REPORTER | ADDRESS | PHONE | INTERVIEW DATE: YR | MO | DAY

OPERATOR OR LICENSEE (40 43) | ADDRESS (44) | PHONE | INTERVIEW DATE: YR | MO | DAY

PIPELINE FAILURE INFORMATION

LICENCE NO (45 50) | LINE NO (51 53) | INSTAL NO (54 55) | LEAK OR RUPTURE L/R (56) | TEST FAILURE T (57) | OPER. PRES. AT TIME & LOC. OF FAILURE (kPa) | M.O.P. (kPa)

(58 65) | LINE O.D. (mm) (66 70) | PIPE TYPE/SPECIFICATION | GRADE (71 74) | WALL TH. (mm) (75 78) | COVER (cm) ± 10 cm

EXTERNAL COATING Y N | INTERNAL COATING Y N | CATHODIC PROTECTION Y N | INT. CORROSION PREVENTION Y N | TYPE

REPAIR LENGTH (m) | PRETEST PIPE Y N | RETEST Y N | PROPOSED / ACTUAL | TEST PRES. (kPa) | DUR.(hr) | TEST MEDIUM

GAS DISCHARGE (10^3m^3): CARD 0 9 0 (15 17) | SWEET/SOUR (24) | VOLUME (29)
WATER OR WATER BASE MATERIAL (m^3): DESCRIPTION | DISCHARGE (30) | RECOVERED (40)
LIQUID HYDROCARBONS (m^3): DESCRIPTION (41) | DISCHARGE | RECOVERED (51)

LIQUID SPILLS

CONTAINED ON LEASE? YES 1 (52) NO 2 (52)
TERRAIN AFFECTED: LAND 1 (59) WATER 2 (59) BOTH 3 (59)
REHABILITATION REQUIRED? YES 1 (66) NO 2 (66)

DESCRIBE EXTENT OF SPILL

CLEAN UP COMP: YR. | MO. | DAY (53 58)
NEXT SCHED INSP: YR. | MO. | DAY (60 65)
REHAB COMPLETE: YR. | MO. | DAY (67 72)

NOISE (73) | ODOUR (74) | SMOKE (75)

REMARKS

INDICATE INTENSITY OF POLLUTANT, CONTINUOUS OR INTERMITTENT - EFFECT OF OCCURRENCE ON HUMANS, LIVESTOCK, CROPS ETC.
DESCRIBE PIPELINE FAILURE, CAUSE ETC.
LIST ACTION REQUIRED —

GOVERNMENT DEPT. NOTIFIED

DEPARTMENT		DATE: YR	MO	DAY
	76			
	77			
	78			
	79			
A. C. D CODE	80			

COMPLAINANT | F4-90-02 | BOARD REPRESENTATIVE

Figure B1. Energy Resource Conservation Board of Alberta Incident Report Form

OIL PIPELINE FAILURE REPORT

PIPELINE COMPANY OR SYSTEM	Name .... Sheet of Address ....
INSTRUCTIONS	1. This report is for pipeline systems covered by CSA Standard Z183 - Oil Pipeline Transportation Systems. All data on this form will be kept confidential in accordance with request in "USE OF DATA" section. 2. A separate report should be made out for each failure and forwarded to CAPP as soon as possible, but not later than 60 days after the failure. 3. A reportable failure is one in which 1.5m³ or more of oil are released; OR one in which any High Vapour Pressure (HVP) material is released; OR one in which there is an injury, a death, a fire, or an explosion. Failures during controlled testing, when using oil as the test medium, should be reported in accordance with these guidelines. 4. Zone location questions apply <u>only</u> to failures involving HVPs. 5. Reports by CAPP members companies must be completed or reviewed for completeness by CAPP Pipeline Technical Committee or member of the Pipeline Standing Committee. 6. Property damage costs reported under Failure Impact will be reported excluding product loss.
NOTE	***Please complete all appropriate sections including "Written Account of Failure" USING TYPEWRITER OR BLACK INK.***
GENERAL INFORMATION	Date of Failure: Year / Month / Day / Time (24 hrs) — Commodity Released — Volume Information - Cubic Metres: Released = Recovered + Lost Province: .... Area type: ☐ Urban ☐ Rural Nearest Town: .... Spill was on: ☐ Land ☐ Water Terrain type: .... Zone location, if applicable: ☐ Zone 1 ☐ Zone 2 Installation year of failed component: 19...... ☐ Line pipe ☐ Pump Station ☐ Tank Farm ☐ Delivery Point
MAJOR CAUSE OF SPILL	Please check ONE only: ☐ Internal Combustion ☐ Defective pipe ☐ Equipment rupturing line ☐ External Combustion ☐ Defective weld ☐ Pipe previously damaged ☐ Operational Error ☐ Equipment failure ☐ Natural hazard ☐ Other (specify):
ORIGIN OF SPILL	Please check as many items as required: ☐ Pipe ☐ Scraper trap ☐ Valve ☐ Meter ☐ Seam weld ☐ Welded fitting ☐ Pump ☐ Prover ☐ Girth weld ☐ Bolted fitting ☐ Tank ☐ Strainer ☐ Other (specify):
DETECTION OF SPILL	☐ Outside Party ☐ Pipeline Employee ☐ Row Surveillance ☐ Leak Detection System Was Leak Detection System in operation? ☐ Yes ☐ No If yes, describe mode of operation ________________ ________________ Time from failure to detection of failure: hours minutes

FAILURE IMPACT...	Number of Injuries		Number of Deaths		Fire	Explosion	Area Damaged (ha)	
	Employees	Others	Employees	Other	☐ Yes ☐ No	☐ Yes ☐ No	Pipeline	Others

Figure B2. Canadian Association of Petroleum Producers Incident Report Form Part (A)

...FAILURE IMPACT	Cleanup Costs	Property Damage Costs		Cleanup Time	Duration of System Shutdown	
		Pipeline	Others			
	$	$	$	Days	Days	Hours

IF FAILURE OCCURRED IN PIPE						
	Pipe Diameter mm	Pipe Wall Thicness mm	Specification and Grade	Type of Seam Weld	Type of Girth Weld	Metallurgical Report Done? ☐ Yes ☐ No
	Depth of Cover if Below Ground cm		Configuration at Point of Failure ☐ Straight ☐ Sag Bend ☐ Side Bend ☐ Overbend	Type of Coating	Condition of Coating	Size of Failure Major Dimension mm
	Allowable Operating Pressure kPa	Pressure at Time and location of Failure kPa	Date of Last Pressure Test Year / Month / Day	Distance to Nearest Valve (km) Upstream	Down-stream	Evidence of Brittle Fracture? ☐ Yes ☐ No / Flowrate at Time of Failure m^3h

IF CORROSION				
	☐ Internal ☐ External	If Internal, was Inhibitor Used ☐☐ Yes No	If External, was System under Cathodic Protection? ☐ Yes ☐ No	Type of Cathodic Protection Appearance of Failed Facility

IF EQUIPMENT RUPTURING LINE				
	Type of Equipment and Activity Causing Failure	Was Equipment operator aware of Pipeline? If yes, how? ☐ Yes .... ☐ No	Was Pipeline aware of Equipment Activity? If yes, how? ☐ Yes .... ☐ No	
	Frequency and Type of ROW Surveillance at Failure Location	Was One-Call System in Operation? ☐ ☐Yes No	Did Failure Occur at Time of Damage? ☐☐ Yes No	
	If previous damage, how long between damage and failure?	Distance to Nearest Warning Sign m		

WRITTEN ACCOUNT OF FAILURE	Include a brief written account of the failure with any special details, recommendations that may prevent similar failures, or information that may assist Standard and Code writing bodies. (Other written reports of the failure may be attached.)

USE OF DATA	Please check ONE only: ☐ Data on this form must be restricted to use by CAPP only. ☐ Data on this form may be reviewed by CSA Z-183 Technical Committee.	
REPORTED BY	Name	Date completed
	Title	Telephone Number
CAPP * MEMBER	Name *if applicable	Date checked
Mail to:	CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS 2100, 350 - 7th Avenue S.W. Calgary, Alberta T2P 3N9	Revised 01/94

Figure B2. Canadian Association of Petroleum Producers Incident Report Form Part (B)

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678. Form Approved OMB No. 2137 0522

U.S. Department of Transportation
Research and Special Programs Administration

INCIDENT REPORT — GAS TRANSMISSION AND GATHERING SYSTEMS

Report Date ______
No. ______
(RSPA)

SEE INSTRUCTIONS

PART 1 — GENERAL REPORT INFORMATION

1. a. Operator's 5 digit identification no. |_|_|_|_|_|
   b. Name of Operator ______
   c. ______ Number and Street
   d. ______ City, County, State and Zip Code
2. Location of Incident
   a. ______ City and County
   b. ______ State and Zip Code
   c. Mile Post/Valve Stat. ______
   d. Survey Station No ______
   e. Class Location
      Onshore ☐ 1 ☐ 2 ☐ 3 ☐ 4
      Offshore ☐ ______ area ______ block number
      State ______ or Outer Continental Shelf ______
   f. Incident on Federal Land other than Outer Continental Shelf
      ☐ Yes ☐ No
3. Incident Type
   ☐ Leak ☐ Rupture ☐ Other
   Rupture Length *(feet)* ______
4. Reason for Reporting
   ☐ Fatality Number ______ persons
   ☐ Injury requiring inpatient hospitalization Number ______ persons
   ☐ Property damage/loss Estimated $ ______
   ☐ Operator Judgment
   ☐ Supplemental Report
5. Elapsed time until area was made safe
   |_|_| hr |_|_| mn
6. Telephonic Report
   |_|_| mo |_|_| day |_|_| yr
7. a. Estimated Pressure at Point and Time of Incident *(PSIG)* ______
   b. Maximum allowable operating pressure *(MAOP) (PSIG)* ______
   c. MAOP established by:
      (1) Test pressure ______ *(PSIG)*
      (2) 49 CFR §192.619(a)(3) ☐
8. Time and Date of the Incident
   |_|_|_|_| hour |_|_| mo |_|_| day |_|_| yr

PART 2 — APPARENT CAUSE

☐ Corrosion *(Continue in Part A)* ☐ Damage by Outside Forces *(Continue in Part B)* ☐ Construction/Material Defect *(Continue in Part C)* ☐ Other ______

PART 3 — NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE INCIDENT

(Attach additional sheet(s) as necessary)

PART 4 — ORIGIN OF THE INCIDENT

1. Incident Occurred On:
   ☐ Transmission System ☐ Gathering System
   ☐ Transmission Line of Distribution System
2. Failure Occurred On:
   ☐ Body of Pipe ☐ Fitting, Specify ______
   ☐ Mechanical Joint ☐ Other, Specify ______
   ☐ Valve ☐ Weld, Specify ______ *(girth, longitudinal, fillet)*
3. Material Involved
   ☐ Steel ☐ Other, Specify ______
4. Part of System Involved in Incident
   a. Part
      ☐ Pipeline ☐ Regulator/Metering System
      ☐ Compressor Station ☐ Other ______
   b. Year installed ______

PART 5 — MATERIAL SPECIFICATION

1. Nominal Pipe Size ______ in
2. Wall Thickness ______ in
3. Specification ______ SMYS |_|_|_|_|_|_|
4. Seam Type ______
5. Valve, Type ______
6. Manufactured by ______ in year |_|_|_|_|

PART 6 — ENVIRONMENT

Area of Incident
☐ Under Pavement ☐ Above Ground
☐ Under Ground ☐ Under Water
☐ Other ______

PART 7 — PREPARER AND AUTHORIZED SIGNATURE

______ *(type or print)* Preparer's Name and Title ______ / ______ Telephone Number

______ Authorized Signature and Date ______ / ______ Telephone Number

Form RSPA F 7100.2 (3-84)

Figure B3. U. S. Department of Transportation Incident Report Form for Gas Transmission and Gathering Pipelines - Part (A)

PART A – CORROSION

1. Where did corrosion occur?
   - ☐ Internally
   - ☐ Externally
2. Visual Description
   - ☐ Localized Pitting
   - ☐ General Corrosion
   - ☐ Other ______________
3. Cause
   - ☐ Galvanic
   - ☐ Other ______________
4. Pipe Coating Information
   - ☐ Bare ☐ Coated
5. Was corroded part of pipeline considered to be under cathodic protection prior to discovering incident?
   - ☐ Yes Year Protection Started |_|_|_|_|
   - ☐ No
6. Additional Information

PART B – DAMAGE BY OUTSIDE FORCES

1. Primary Cause of Incident
   - ☐ Damage resulted from action of operator or his agent
   - ☐ Damage resulted from action by outside party/third party
   - ☐ Damage by earth movement
     - ☐ Subsidence
     - ☐ Landslide/Washout
     - ☐ Frost
     - ☐ Other ______________
2. Locating information *(for damage resulting from action of outside party/third party)*
   a. Did operator get prior notification that equipment would be used in the area?
      - ☐ Yes Date received |_|_| mo |_|_| day |_|_| yr
      - ☐ No

   b. Was pipeline location marked either as a result of notification or by markers already in place?
      - ☐ Yes Specify type of marking: ______________
      - ☐ No

   c. Does Statute or ordinance require the outside party to determine whether underground facility(ies) exist?
      - ☐ Yes
      - ☐ No
3. Additional Information

PART C – CONSTRUCTION OR MATERIAL DEFECT

1. Cause of Defect
   - ☐ Construction ☐ Material *(describe in C.4 below)*
2. Description of Component Other than Pipe
3. Latest Test Data
   a. Was part which leaked pressure tested before incident occurred?
      - ☐ Yes Date of Test |_|_| mo |_|_| day |_|_| yr
      - ☐ No

   b. Test Medium ☐ Water ☐ Gas ☐ Other ______________

   c. Time held at test pressure |_|_| hr

   d. Estimated test pressure at point of incident *(psig)* ______________
4. Additional Information

Figure B3. U. S. Department of Transportation Incident Report Form for Gas Transmission and Gathering Pipelines - Part (B)

ACCIDENT REPORT-HAZARDOUS LIQUID PIPELINE

Report Date ____

No. 7000-1
(DOT)

PART A—OPERATOR INFORMATION

1.) Name of operator ____
2.) Principal business address ____

____
(city) *(state)* *(zip code)*

3.) Is pipeline interstate? ☐ yes ☐ no

PART B—TIME AND LOCATION OF ACCIDENT

1.) Date: *(month)* ____ *(day)* ____ *(year)* ____
2.) Hour *(24 hour clock)* ____
3.) If onshore give state *(including Puerto Rico and Washington, D.C.)*, and county or city. ____
4.) If offshore, give offshore coordinates ____
5.) Did accident occur on Federal Land? ☐ yes ☐ no
(See instructions for definition of Federal Land.)
6.) Specific location *(If location is near offshore platforms, buildings, or other landmarks, such as highways, waterways, or railroads, attach a sketch or drawing showing relationship of accident location to these landmarks)*

____
____
____

PART C—ORIGIN OF RELEASE OF LIQUID OR VAPOR.

(Check all applicable items)

1.) Part of system involved:
☐ line pipe ☐ tank farm ☐ pump station
2.) Item Involved: ☐ pipe ☐ valve ☐ scraper trap ☐ pump
☐ welding fitting ☐ girth weld ☐ tank
☐ bolted fitting ☐ longitudial weld

Other *(specify)* ____
3.) Year item installed ____

PART D—CAUSE OF ACCIDENT

☐ corrosion ☐ failed weld ☐ incorrect operation by operator personnel
☐ failed pipe ☐ outside force damage
☐ malfunction of control or relief equipment.
☐ other *(specify)* ____

PART E—DEATH OR INJURY

1.) Number of persons killed. ____
____ Operator employees ____ Non-employees
2.) Number of persons injured. ____
____ Operator employees ____ Non-employees

PART F—ESTIMATED TOTAL PROPERTY DAMAGE

S ____

PART G—COMMODITY SPILLED

1.(Name of commodity spilled: ____
2.) Classification of commodity spilled:
☐ Petroleum Petroleum product ☐ HVL· or ☐ Non-HVL
3.) Estimated amount of commodity involved
____ Barrels spilled ____ Barrels recoverd
4.)' Was there an explosion?
☐ yes ☐ no
5.) Was there a Fire?

Figure B4. U. S. Department of Transportation Incident Report Form for Hazardous Liquid Pipelines - (Part A)

INSTRUCTIONS: Answer sections H, I, or J only if it applies to the particular accident being reported.

PART H—OCCURRED IN LINE PIPE

1.) Nominal diameter *(inches)* ________ 2.) Wall thickness *(inches)* ________

3.) SMYS *(psi)* ________ 4.) Type of joint: ☐ welded ☐ flanged ☐ threaded ☐ coupled ☐ other

5.) Pipe was ☐ Below ground ☐ Above ground

6.) Maximum operating pressure *(psig)* ________

7. Pressure at time and location of accident *(psig)* ________

8.) Had there been a pressure test on system?
☐ yes ☐ no

9.) Duration of test *(hrs)* ________

10.) Maximum test pressure *(psig)* ________

11.) Date of latest test ________

PART I—CAUSED BY CORROSION

1. Location of corrosion
☐ internal ☐ external

2. Facilty coated?
☐ yes ☐ no

3. Facilty under cathodic protection?
☐ yes ☐ no

4. Type of corrosion
☐ galvanic ☐ other *(Specify)*
____

PART J—CAUSED BY OUTSIDE FORCE

1. ☐ Damage by operator or its contractor
☐ Damage by others
☐ Damage by natural forces
☐ Landslide
☐ Subsidence
☐ Washout
☐ Frostheave
☐ Earthquake
☐ Ship anchor
☐ Mudslide
☐ Fishing Operations

Other ________

2. Was a damage prevention program in effect
☐ yes ☐ no

3. If yes, was the program
☐ "one-call" ☐ other ________

4. Did excavator call?.
☐ yes ☐ no

5. Was pipeline location temporarily marked for the excavator?
☐ yes ☐ no

PART K—ACCOUNT OF ACCIDENT

NAME AND TITLE OF OPERATOR OFFICIAL FILING THIS REPORT.

____

________ Telephone no. *(Including area code)*

________ Date

Figure B4. U. S. Department of Transportation Incident Report Form for Hazardous Liquid Pipelines - (Part B)

APPENDIX C

REVIEW OF RISK ANALYSIS APPROACHES IN THE PIPLINE INDUSTRY

C.1 Introduction

The application of risk analysis in the pipeline industry was reviewed, with special emphasis on using risk analysis as a basis for making decisions on integrity maintenance activities. The approaches can be broadly classified in two categories:

1. ***Index systems***. This approach is based on the premise that the risk associated with pipelines cannot be quantified probabilistically because of the complexity of the issues involved and the scarcity of statistical failure data. The basic method is to define a subjective score for the pipeline segment under consideration with respect to the different attributes that affect the risk. The final risk index is then defined by combining the individual attribute scores according to a formula that takes into account the relative importance of different attributes and how they interact together in influencing risk.
2. ***Quantitative risk assessment***. This approach is based on calculating the risk as the product of the probability of failure and a measure of the failure consequences. The probability of failure is usually based on historical failure data. Failure consequences are usually estimated from product release and hazard characterization models.

Both types of models have been used and described in the literature. Recent summary reports on the application of quantitative risk analysis to pipelines have been prepared by Concord (1993) for the Canadian Association of Petroleum Producers and by Bercha (1994) for the National Energy Board. The main features of the different implementations of these two approaches are given in Sections C.2 and C.3. A bibliography of the literature reviewed is included in Section C.4.

Appendix C

C.2 Index Systems

C.2.1 Description

Most pipeline risk index systems are developed and used internally by pipeline operators (e.g., Dusek 1994, Mahlbauer 1992, Kiefner *et al*. 1990, and Ahmad 1988). The approach developed by Dow Chemical is described in detail in a book by Mahlbauer (1992) and is used as a basis for this discussion. Mahlbauer defines a safety index as follows:

$$Safety\,Index = \frac{Failure\,Resistance\,Index}{Failure\,Impact\,Index} \qquad [C.1]$$

where the failure resistance factor is given by

$$\begin{aligned} Failure\,Resistance\,Index = {} & Corrosion\,Index + Third\,Party\,Index \\ & + Design\,Index + Operations\,Index \end{aligned} \qquad [C.2]$$

and the failure impact index defined as

$$Leak\,Impact\,Index = Product\,Hazard\,/\,Dispersion\,Factor \qquad [C.3]$$

Equation [C.1] can be seen to correspond to the usual definition of risk as the product of the probability of failure and the consequences of failure (with risk = 1 / safety index, probability of failure = 1 / failure resistance, and consequences of failure = failure impact index).

Each of the Indexes in Equations [C.1] and [C.2] are quantified by assigning a score to the attributes that affect the corresponding element. The relative magnitudes of the maximum scores for each attribute reflect the importance of the attribute. For example, the Third Party Index in Equation [C.2] is defined as the sum of the scores for the following attributes:

• Depth of cover	0 - 20 points	20%
• Activity level	0 - 20 points	20%
• Above ground facilities	0 - 10 points	10%

• One-call system	0 - 15 points	15%
• Public education	0 - 15 points	15%
• Right of way condition	0 - 5 points	5%
• Patrol frequency	0 -15	15%

Each of the failure indexes in Equation [C.2] is allocated an equal maximum score of 100 points for a total maximum of 400 points.

The leak impact index is obtained by dividing the product hazard by the dispersion factor as shown in Equation [C.3]. The product hazard is the sum of two indexes describing chronic and acute hazards, with the latter being defined as a function of product flammability, reactivity and toxicity. The dispersion factor represents the level of exposure of people to the hazard as determined by the population density and the chemical stability of the product.

The index approach developed by Kiefner *et al.* (1990) for the Pipeline Research Committee of the American Gas Association is also worth mentioning here. Although the overall approach is essentially the same as the Mahlbauer approach, Kiefner *et al.* have different formulas for estimating the probability index and the consequence index. These formulas have some built-in analytical features, which are intended to reflect the experience of the authors regarding the manner in which different parameters influence the risk. For example, quantities such as pipe thickness, diameter, MAOP, last test pressure, number of leaks and ruptures in the past are used directly in calculating the index. Also, indexes representing the presence of stress corrosion cracking pipe condition (with respect to metal loss corrosion) and coating condition are all squared in the algorithm to highlight their importance in defining the probability index. Further the contribution of ductile fracture propagation is based on an expression that defines the charpy toughness required to arrest a ductile fracture under the MAOP. This model has been demonstrated by several example cases and has been coded in a computer program.

C.2.2 Assessment

Index system are easy to use since they do not require statistical data or detailed calculations. It is usually possible to implement them as a "recipe" by an engineer who is familiar with the pipeline being analyzed. They give a ranking of the different segments of a pipeline system which can be used a basis for prioritizing these segments for integrity maintenance actions. Mahlbauer (1994) also suggested that they can be used as a basis for economic analysis of different maintenance options.

Index systems are helpful and worthwhile in the absence of more detailed quantitative approaches. They are however subject to a fundamental limitation related to the relative magnitude of the scores assigned to different attributes. If the importance of a certain action or attribute is over- or under-estimated, the resulting ranking will be inaccurate. For example, the Mahlbauer approach accounts in-line inspection for metal loss corrosion by awarding 8 points out of a total of 400 points representing resistance to failure (*i.e.* 2%). This underestimates the benefits of high resolution pigging which is known to result in significant reductions in the probability of corrosion failures, which historically account for between 20% and 40% of all failures.

The other disadvantage of index systems is that they do not give an absolute estimate of the risk, but only a relative ranking. Absolute risk estimates are needed to decide whether a certain segment requires any maintenance action in the first place. In other words, knowing that segment A is worse that segment B is not sufficient to decide whether A or B (or both) require additional maintenance action to reduce the risk level.

C.3 Quantitative Risk Assessment

C.3.1 Description

There are many reports in the literature that describe the use of quantitative risk assessment of pipelines as a basis for decision making regarding integrity maintenance. The basic concept of quantitative risk assessment is to estimate the probability of failure of the pipeline and quantify the associated consequences. The risk is then estimated as

$$Risk = Probability\,of\;Failure \times Consequences\,of\;Failure \qquad [C.4]$$

Appendix C

Distinctions between the approaches adopted by different authors usually relate to the methods used in evaluating failure probabilities and failure consequences. The most significant quantitative risk assessment initiatives are described in the following:

- Fearnehough (1985) and Fearnehough and Corder (1992) describe the approach used by British Gas as a basis for design and inspection decisions. The focus of this analysis is on risk to life. Two methods were used to estimate the failure probability, namely historical data collected by British Gas for their system and fracture mechanics criteria for pipelines with defects that are characterized by on-line inspection. Detailed models were used to estimate the levels of exposure to thermal radiation, both out-door/in-door, from the release rates and the probabilities of immediate and delayed ignition. The thermal radiation estimates were verified by the results of full scale tests. The criterion used to determine whether a certain pipeline is acceptable was based on the tolerable individual risk levels given in the guidelines developed by the U.K. Health and Safety Executive (HSE 1989). British Gas is currently consolidating its work on the estimation of life safety risks in a computer package (TRANSPIRE) that is being developed under a joint industry program (Hopkins *et al.* 1993).
- Urednicek *et al.* (1992) describe a model used by Nova to make decisions on integrity maintenance of their gas transmission pipelines. Both safety and economic risks were considered; however, since safety risks were found to be very low based on Nova's experience, economic risks became the major concern. Economic risk was calculated as the product of outage probability and outage cost. The outage probability was estimated using a fault tree that incorporates different failure causes (*e.g.*, external corrosion, stress corrosion cracking, mechanical damage, construction fracture, material defect, slope instability). The failure data used in the fault tree analysis were obtained from failure statistics supplemented by analysis. The cost of outage was estimated as the sum of repair cost, cost lost of product and the estimated cost due to the interruption of operation. Rehabilitation was considered necessary for segments that have a total risk exceeding the tolerable level of $500,000/per km per year. Ronsky and Trefanenko (1992) of Novacor described the use of this model to optimize integrity expenditures for a number of case studies including review of inspection strategies for an offshore pipeline, and comparing low resolution and high resolution pigs.

- Kulkarni *et al.* (1993), Kulkarni and Conroy (1991) describe a risk-based integrity maintenance optimization program (PIMOS) that is under development by Woodward-Clyde Consultants for the Gas Research Institute. The focus of this program is to use a risk-based approach to make decisions regarding optimal integrity maintenance actions and plans. Decision trees are used as the basic approach for optimization. The probabilities of failure are to be calculated by correlating the historical failure frequencies to different attributes of the pipeline. To incorporate the effect of integrity maintenance on the failure rate, these attributes will include the integrity maintenance actions that were being implemented for different systems when they failed. It is proposed that the data required for this will be collected from different pipeline companies in a format suitable for the analysis. The consequence models are said to consider both the direct costs of the actions (i.e. inspection and maintenance costs) as well as risk related costs (e.g. repair cost, cost of service interruption and costs associated with property damage, injury and fatalities).

Other reports of quantitative pipeline risk assessment work include the work by Arthur D. Little Limited (Hill 1992), which focussed on risk to life safety in due to spills from oil pipelines. DnV Technica has analyzed the risk associated with crude oil spills from Arctic pipelines (Weber and Mudan 1992). The main concern of this study was the calculation of leak sizes and their probabilities, considering such parameters as the duration of spill as determined by the time required for shutdown and leak isolation. Concord Environmental Corporation has also produced reports on risk assessment of sour gas pipelines (Zelensky *et al.* 1989, Alp *et al.* 1990a). A major contribution from this work is the development of the computer program GASCON2 (Alp *et al.* 1990b), which incorporates state-of-the-art gas release and dispersion models. All of the approaches mentioned in this paragraph used historical data as a basis for estimating probabilities of failure, with Concord suggesting the use of fault trees as an aid in this process.

C.3.2 Assessment

Existing approaches for quantitative risk assessment are mostly intended to determine whether the risk level associated with a certain pipeline segment is acceptable. These approaches contribute a significant amount of the information needed to carry out a risk-based optimization analysis. The limitations of existing approaches with respect to risk-based optimization are as follows:

- Each approach focuses primarily on only one aspect of the total consequences of pipelines (*i.e.*, life safety, cost or environmental impact). There have been no approaches that integrate to all three types of consequences.
- The probabilities of failure are estimated from historical data in most cases (although supplemented by fault tree analyses and some structural modelling of the pipe in some cases). Existing publicly available data bases generally do not support the level of detail required to obtain the needed failure rate (see Appendix A for further discussion of this aspect). Specifically, it will be difficult to determine the impact of different maintenance strategies on the failure rate using historical failure rate data.
- The area of environmental risk has not been addressed in detail in any of the risk-based approaches reviewed.

C.4 Bibliography

Ahmad, H. 1988. Economic and Risk Analysis for Gas Line Replacement, Pipe Line Industry, February, pp. 17-19.

Alp, E., Davies, M. J. E., Huget, R. G., Lam, L. H. and Zelensky, M. J.1990a. Risk Approach, An Approach for Estimating Risk to public Safety from Uncontrolled Sour Gas Releases, ERCB Report 90-B, Vol.6, Concord Environmental Corp., Calgary, Alberta.

Alp, E., Huget, R. G., Oliverio, M., Davies, M. J. E., Lam, L. H. and Zelensky, M. J. 1990b. GASCON2–A model to estimate ground level H_2S and SO_2 concentration and consequences from uncontrolled sour gas releases, ERCB Report 90-B, Vol.5, Concord Environmental Corp., Calgary, Alberta.

Bercha 1993. Risk Analysis Basis for Pipeline Life Cycle Safety, Final Report to the National Energy Board by F.G. Bercha and Associates Limited, Calgary, June.

Concord 1993. Risk Assessment Techniques for Pipeline Systems, prepared for the Pipeline Environmental Committee of the Canadian Association of Petroleum Producers, Concord Environmental Corporation, Calgary, Alberta.

Dow Chemical 1987. Fire and Explosion Index Hazard Classification Guide, sixth edition, Dow Chemical Company.

Appendix C

Dusek, P. J. 1994. Pipeline Integrity Program. Pipeline & Gas Journal, March, pp. 36-40.

Fearnehough, G. D. 1985. The Control of Risk in Gas Transmission Pipeline. Institute of Chemical Engineers, Symposium, No.93, pp. 25-44.

Fearnehough, G. D. and Corder, I. 1992. Application of Risk Analysis Techniques to the Assessment of Pipeline Routeing and Design Criteria. International Conference on Pipeline Reliability, Calgary, Alberta.

Hill, R. T. 1992. Pipeline Risk Analysis. Institution of Chemical Engineers Symposium Series, No.130, pp. 637-670.

Hopkins, H. F., Lewis, S. E., and Ramage, A. D. 1993. The Development and Application of the British Gas TRANSPIRE Pipeline Risk Assessment Package. Presented at the Institution of Gas Engineers, Midland Section Meeting, Loughborough, October.

HSE 1989. Risk Criteria for Land-Use Planning in the Vicinity of Major Industrial Hazards, United Kingdom Health and Safety Executive, London, U. K.

Kiefner, J. F., Vieth, P. H., Orban, J. E. and Feder, P. I. 1990. Methods for Prioritizing Pipeline Maintenance and Rehabilitation. American Gas Association.

Kulkarni, R. B. and Conroy, J. E. 1991. Development of a Pipeline Inspection and Maintenance Optimization System (Phase I). Gas Research Institute Contract No. 5091-271-2086.

Kulkarni, R. B., Conroy, J. E., Wilke, T. L., Werner, D. P., and Krauss, W. E. 1993. Inspection and Maintenance Priorities for Gas Transmission, Gas Industries, Vol. 37, No. 10, pp. 15-17.

Muhlbauer, W. K. 1992. Pipeline Risk Management Manual, Gulf Publishing Company, Houston, Texas.

Muhlbauer, W. K. 1994. Economic Considerations for Pipe Line Risk Management. Pipe Line Industry, February, pp. 39-44.

Ronsky, N. D. and Trefanenko, B. 1992. "Managing Pipeline Integrity: A Look at Cost and Benefits", Proceedings of the 11th International Conference on Offshore Mechanics and Arctic Engineering, Vol. V-B, pp. 299-306.

Urednicek, M., Coote, R. I. and Coutts, R. 1992. "Optimizing Rehabilitation Process with Risk Assessment and Inspection", proceedings of the International Conference on Pipeline Reliability, Calgary, June, II-12-1 to II-12-14.

Weber, B. J. and Mudan, K. S. 1992. "Arctic Pipeline Risk Assessments", Proceedings of the Second International Offshore and Polar Engineering Conference, San Francisco, Vol. II, June, 15 - 20.

Appendix C

Zelensky, M. J., Napier, D. H. and Portelli, R. V. 1989. Risk Assessment, Husky Oil Caroline Development Project, Vol. 10, Concord Environmental Corp., Calgary, Alberta.