TOTAL PIPELINE INTEGRITY

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1. INTRODUCTION

An operator needs to maintain a safe pipeline, and ensure it has a long and profitable life. Consequently, he must consider integrity strategies that are both cost effective and prevent failures or large repair / rehabilitation bills.

To ensure 'Total Pipeline Integrity' an operator requires a package of products customised to their pipeline integrity requirements. Figure 1 shows customised packages including: -

? the rehabilitation of 2,300 km of pipelines in Mexico (1) saving over $12 million
? the rehabilitation of a 450 km onshore products pipeline in Africa avoiding $300 million replacement costs
? the development of a maintenance plan for 1,500 km of onshore gas pipelines in the Far East reducing the current annual maintenance and repair costs by 20%

This paper presents case studies of typical 'Total Pipeline Integrity' projects conducted in the last five years and which have saved operators over $1 billion.

2. BACKGROUND

Engineering structures follow a 'bath tub' failure probability curve (Figure 2). During a structure's life the highest failure probability is when the structure is new, or later when it has deteriorated. For example, pipelines have historically suffered high failure rates early in life (e.g. during the pre-service pressure test) and later in life (due to time dependent damage, e.g. corrosion, fatigue).

At any stage of a pipeline's life, an operator needs to consider an overall strategy to ensure pipeline integrity at optimum cost. These considerations are against a background of the move world-wide to replace the prescriptive framework for pipelines by a modern goal-setting regime (2,3). In particular, operators are required to provide a case demonstrating that they have reduced the risks arising from operation of a pipeline to a level 'as low as reasonably practicable'.

A solution can be provided to any pipeline integrity issue. Examples are now presented relating to: -

? Increasing planned pre-service hydrotest level
? Defect assessment
? Planning maintenance and rehabilitation

- ? Determining inspection intervals (RBI – Risk Based Inspection)
- ? Extending the life of corroding pipelines
- ? Rehabilitation of a pipeline system
- ? Assessing risk to public
- ? Uprating pipelines
- ? Life extension of a pipeline system

3. PRE-SERVICE HYDROTEST

The first example relates to a 235 km, offshore, natural gas pipeline which had been designed to BS 8010 and a pre-service hydrotest to 175 bar was required. However, it was recognised that there may be a requirement to uprate the pipeline in the future. Therefore, it was considered prudent to make an allowance for this by increasing the hydrotest pressure by 5% to 185 bar.

The pipeline had been constructed with 40 inch diameter, 21.8 mm wall thickness grade EP450 LSAW (longitudinally seam arc welded) pipe. Although the pipes had previously been hydrotested in the pipe mill, it was to a level lower than 185 bar. Consequently, there was a risk that a manufacturing defect could be present in the pipeline and result in a failure during the planned pressure test.

The most severe type of defect in a buried pipeline subjected to internal pressure is an axially orientated defect. Historically the majority of pre-service hydrotest failures in seam welded pipe have been associated with axial weld toe defects. The distribution of such defects in this pipeline was conservatively estimated using historical hydrotest failure data. Bayesian updating methods were applied to modify this distribution on the basis that the pipes had been subjected to ultrasonic examination and had survived a hydrotest to 178 bar in the pipe mill.

Probabilistic methods were utilised to determine the relationship between the probability of failure and the hydrotest pressure (Figure 3). It was concluded that increasing the hydrotest from 175 bar to 185 bar was insignificant in terms of the probability of failure. The pipeline is now in operation following the successful hydrotest to 185 bar.

4. DEFECT ASSESSMENT

All engineering structures contain defects. Historically, defect acceptance levels have been based on standards of “good workmanship” e.g. a girth weld defect is acceptable provided its dimensions do not exceed those expected in a weld produced by a “good” welder. These defect acceptance levels have no technical basis and consequently vary significantly in world-wide Codes (e.g. BS 4515, API 1104, CSA Z184). Furthermore theses Codes can require the repair of defects e.g. slag or porosity which are innocuous.

In the mid-1970’s alternative fracture mechanics based methods became generally available. These methods (i) relate the severity of a defect (dimensions) to the material properties (toughness and tensile) and required operating conditions, and (ii) are permitted as an alternative to good workmanship in all the above Codes.

The methods are codified (e.g. BS 7910) and generally allow larger defects to remain in a structure than "good workmanship" standards. However it is generally accepted that good workmanship standards should prevail in a new construction. Defects detected in-service should be assessed on the basis of the above fracture mechanics techniques, referred to as a "Fitness-For-Purpose" assessment. It is highlighted that codified fracture mechanics methods should be used with care because they can be highly conservative. Two examples are now presented

Girth Weld Defects (4)

A 36 inch diameter offshore gas pipeline had operated satisfactorily in the North Sea for 17 years. An internal inspection was conducted and five girth weld cracks were reported. The most extensive crack was reported on the shore approach, and was removed to confirm the presence and reported size of the crack (Figure 4). Our subsequent fitness-for-purpose assessment included: (i) extensive calculations, (ii) extensive mechanical and toughness testing to confirm that, other than the crack, there was no evidence that the weld was sub-standard and (iii) devising and conducting a programme of four full scale tests. The programme involved designing and constructing a test rig and conducting the world's first full scale tests of a defective weld subjected to internal pressure, external bending and low temperature (Figure 5). It was concluded that the remaining four subsea cracked girth welds have no effect on the integrity of the pipeline avoiding repairs costing more than $5 million.

Corrosion Defects (5)

This example illustrates the need to avoid unnecessary repairs. Kuwait Oil Company operates a 92 km, 30 inch onshore crude oil pipeline. The pipeline was commissioned in 1958, and inspected (by PII) for the first time in 1997. The inspection detected 173 084 features (114 086 external corrosion, 56 302 internal corrosion and 2 696 manufacturing defects). There were 100's of features with depths exceeding 50% wt.

According to the relevant assessment Code (ANSI/ASME B31.G) over 3 000 of the corrosion features required immediate repair. However, using more accurate and accepted fitness-for-purpose methods it was confirmed that only 6 corrosion features required repair.

5. PLANNING PIPELINE MAINTENANCE AND REHABILITATION

Pipelines are routinely inspected and monitored using many direct and indirect techniques to ensure that:

(i) pipelines do not become defective or damaged ('proactive' methods), and
(ii) damage or defects are detected before they cause serious problems ('reactive' methods).

An operator should assess the greatest damage/defect risk to the pipeline, then select an appropriate monitoring/inspection method (Table 1) to reduce that risk.

A method for determining which maintenance technique to use and on which pipeline, is a 'Prioritisation Scheme' (qualitative risk assessment).

A Prioritisation Scheme considers the probability and consequences of failure (Figure 6) within a group of pipelines (or sections of a single pipeline) by systematically assessing the pipelines' design, operation and failure history and allocating points. High points indicate high risks. For example, the probability of failure due to external corrosion is evaluated by considering the quality of the pipe coating, the effectiveness of the CP system, the soil conditions, the operating stress level of the pipeline, etc., and the consequences of failure are considered by estimating the density of the surrounding population, the volume of product released, the risk to the population and surrounding buildings, the security of supply, the environmental impact, etc.

DEFECTS/ DAMAGE	MONITORING/INSPECTION METHOD P = PROACTIVE METHOD, R = REACTIVE						
	Aerial Ground Patrols	Intell-igent Pigs	Product Quality	Leak Surveys	Geotech Surveys & S. Gauges	CP & Coating Surveys	Hydro-Test
3rd Party Damage	P	R					R
Ext. Corrosion		R				P	R
Int. Corrosion		R	P				R
Fatigue/Cracks		R					R
Coatings						P	
Materials/Construction Defects		R					R
Ground Movement					R		
Leakage	R	P		R			R
Sabotage/Pilfering	P						

(Visual examinations are not included).

Table 1. Pipeline Inspection and Monitoring Methods

The great advantage of this scheme is that it can:

(i) rank all the pipelines within a group (or sections of a pipeline) in terms of the probability of failure, and the consequences of failure,

(ii) determine which pipeline (or section of a pipeline) is most in need of some type of maintenance measure, i.e. identify 'hot-spots' of risk, and

(iii) identify the most appropriate maintenance measure to use.

A pipeline prioritisation software package ('ASPIRE' - A System for Pipeline Risk Evaluation) has been developed. The operators' knowledge, experience and awareness is utilised to customise ASPIRE to the pipeline system under consideration. ASPIRE can be applied to all types of pipeline systems and even to old systems where the available records may be limited. ASPIRE can be continuously updated with the findings of maintenance work and any damage incidents and consequently can be utilised to prioritise the pipelines for future rehabilitation and maintenance activities.

ASPIRE has been successfully utilised to plan: -

? the rehabilitation, for example, of an onshore gas pipeline system in Bulgaria (6) (see Section 8 for details).

? the cost effective maintenance of pipeline systems world-wide, including:

- 9 pipeline sections of the Pemex E&P, Mexico, crude oil and gas transmission system (7),
- 22 pipeline sections of a natural gas, ring main, system in Argentina (8), and
- 43 pipeline sections of the Pemex Refinacion refined products pipeline in Mexico (9).
- and currently to 4,500km onshore gas system in South America, 1,500km refined products pipeline system in Europe and to 150km offshore gas, crude oil, water flow lines in the Far East.

6. DETERMINING THE TIMING OF FUTURE INSPECTIONS

The ASPIRE approach described above is a qualitative risk assessment method and is an excellent tool to apply to a system of pipelines particularly when the input data is limited. However, once knowledge of the condition of a pipeline or system of pipelines is obtained, for example by conducting one or more intelligent pig inspections, a quantitative risk assessment approach (i.e., RBI – risk based inspection) can be applied to determine the optimum interval for future inspections.

Although intelligent pig inspection detects more than corrosion damage, the main reason for running intelligent pigs is usually to monitor the occurrence and growth of internal and/or external corrosion damage and ultimately to prevent failures. Actual corrosion growth rates can be determined from repeat inspections. This data together with information from corrosion prevention and control activities can be utilised to develop corrosion growth rate models for predicting future corrosion growth patterns. This allows the relationship between the number of repairs and/or failures and time to be predicted (Figure 7a). In addition, probabilistic methods can be utilised to model the variation associated with pipe geometry, material properties, inspection sizing tolerances and corrosion rates and the relationship between the pipeline probability of failure and time can be determined (Figure 7b). Then based on the appropriate re-inspection criteria (e.g., re-inspect before (i) ‘x’ repairs or one failure occurs (Figure 5a) or (ii) the target probability of failure is exceeded (Figure 7b)) the optimum timing of the next inspection can be determined.

The timing of future inspections can also be obtained from cost-benefit analysis (Figure 8a). For example, the cost of failure as a function of time can be predicted (based on the failure frequency, loss of supply costs and failure and repair costs) and compared to the cost of conducting inspections at a range of different time intervals (Figure 8b). Thus the most cost-effective inspection schedule based on the minimum total life cost can be selected.

7. EXTENDING THE LIFE OF CORRODING PIPELINES

Active corrosion in both onshore and offshore pipelines is an increasing problem. Consequently, pipeline operators now regularly use intelligent inspection pigs to detect and size corrosion. Inspection data can be combined with probability based 'fitness-for-purpose' assessment methods to determine the effect of the corrosion on the immediate and future integrity of the pipeline. Three examples are now described.

Example 1: Assessment of an Onshore Pipeline with Internal Corrosion Based on 1 Inspection (10)

As part of its 4000 km Main Oil Line System, Petroleum Development Oman (PDO) operate an onshore, 138 km long, 610 mm diameter, sour crude oil pipeline commissioned in 1987. The pipeline was inspected by PII in 1995 and extensive internal corrosion (pitting and 'slot-shaped' corrosion) up to 80% wt deep was detected along the full length of the pipeline.

The significance of the corrosion was determined using probabilistic fitness-for-purpose methods. Future corrosion growth rates were estimated (based on PDO's three year corrosion monitoring programme). The probability of failure of the pipeline with time was determined in relation to the number of repairs to the most severe corrosion (Figure 9). For example, repairing the 24 deepest corrosion defects extended the life of the pipeline from 0 to 2 years.

Furthermore it was necessary to prevent the situation where the 'corrosion/failure' process could go out of control (i.e., many failures occur) leaving insufficient time to react (i.e., repair/replacement) and hence continued operation becoming uneconomic. Figure 10 shows the relationship between the probability of 'x' failures occurring and time, the low probability of 'many' failures confirming that the internal corrosion (at least in the short term) could be controlled using a re-inspection and repair strategy.

The inspection, probabilistic fitness-for-purpose assessment and epoxy shell repair of the most severe corrosion allowed the sectional replacement of the pipeline to be postponed, resulting in an initial immediate saving of $5 million.

Example 2 : Assessment of an Offshore Pipeline with Internal Corrosion Based on 1 Inspection (11)

This example demonstrates the benefits of using state-of-the-art inspection techniques, defect assessment and probabilistic fitness-for-purpose methods.

The BP Amoco Forties Delta to Forties Charlie 20 inch diameter crude oil pipeline was inspected by the PII Type 3 Magnetic Flux Leakage (T3 MFL) and Transverse Field Inspection (TFI) inspection vehicle in late 1998. Slab, groove and pitting corrosion had previously been detected in another similar BP Amoco pipeline and was expected in this pipeline.

The T3 MFL vehicle is a development of PII's standard MFL vehicle where the primary sensors have been replaced by Type 3, Hall effect, sensors. These sensors measure the magnetic field strength (e.g. at over 66000 locations per metre with the 20 inch T3 MFL) at the internal surface of the pipe and from this data the local wall thickness can be determined.

The TFI vehicle is a new magnetic flux inspection vehicle, which is designed to provide improved detection and sizing of narrow, axial oriented, groove-like defects within the pipeline. The TFI's magnetic field is applied (transverse) around the pipe circumference to allow axial defects to be detected by the sensors. The development of the TFI vehicle is fully detailed in Reference (12).

The T3 MFL and TFI inspections detected 5437 metal loss features, the majority were characteristic of internal corrosion at the bottom of the pipe and along the complete length of the pipeline with over 20 areas of slab corrosion and 58 axial grooves with depths > 30% wt. A comparison of the T3 MFL and TFI inspection data from one area of corrosion is shown in Figure 11.

Other organisations could not justify continued operation of the pipeline. PII developed a strategy to justify the required 15 years further operation. A probabilistic assessment was conducted to determine the relationship between remaining life, risk level, future corrosion growth rates and operating pressure (Figure 12). This provided BP Amoco with the technical basis for defining appropriate safe operating strategies for all future conceivable operating pressures and corrosion growth rates.

Example 3 : Assessment of an Offshore Pipeline with Internal Corrosion Based on Repeat Inspections (13)

A major oil company in the Middle East operates a 1067 mm diameter, 59 km long crude oil pipeline. The pipeline was commissioned in 1983. PII have conducted four inspections of the pipeline in 1990, 1992, 1995 and 1997. Following each inspection internal corrosion was reported along the full length of the pipeline. Since internal corrosion was first reported in 1990, the operator has continually been taking corrosion control measures (i.e. inhibitor treatments) aimed at preventing/reducing the occurrence of further corrosion growth in the pipeline.

Following the inspection in 1995, a study was conducted to determine:

(i) whether or not the corrosion control measures had been successful (i.e. was the corrosion still active), and
(ii) to investigate the future integrity of the pipeline and to recommend remedial measures in the event that the water cut increases.

In order to estimate corrosion growth in the pipeline, a sample of more than 100 corrosion defects, representative of the corrosion throughout the pipeline, were selected. The signals associated with these defects from all the inspections were examined and the extent of growth determined. Statistical analysis of all the results, to remove sizing tolerance effects, indicated that corrosion growth rates were estimated to be > 1 mm/year before 1990, and 0.36 mm/year between 1990 and 1992. There was no statistical evidence of growth between 1992 and 1995. These findings confirmed that the corrosion control measures taken by the operator, particularly since 1990, had been successful.

A probabilistic assessment was conducted to determine the pipeline probability of failure with time. The relationship between probability of failure, operating pressure, repair, corrosion rate and time was investigated (Figure 13). The results highlighted that in terms of the pipeline remaining life, the benefit associated with repairing the most severe corrosion defects or with derating the pipeline was negligible, whereas, maintaining a low corrosion rate was critical in ensuring the future integrity of the pipeline.

The probabilistic assessment summarised above provided the operator with the technical basis required to ensure the long term integrity of the pipeline. For example, if the future corrosion rate can be limited to 0.025 mm/year the operating life of the pipeline could be extended by > 30 years. The cost of corrosion monitoring and control measures to achieve this corrosion rate over 30 years was estimated at 60 million US$ (present day value). The alternative of pipeline replacement is estimated at 250 million US$ (present day value).

8. REHABILITATION OF A PIPELINE SYSTEM (6)

The Bulgargaz pipeline system was constructed between 1972 and 1986 and consists of approximately 2000 km of 28 to 40 inch diameter pipelines with a design pressure of 55 bar. Funding (provided under an EU PHARE programme) was made available to allow the rehabilitation of one pipeline only.

Initially the pipeline system was prioritised (Figure 14) using ASPIRE (see Section 5). The Beglezh to Novi Iskar pipeline had the highest risk and internal inspection was required and conducted in June 1997 (the first inspection pig to be run in a Bulgarian pipeline). The inspection detected 5034 metal loss features (3926 external corrosion, 145 internal metal loss and 963 manufacturing defects), 516 dents and 6 patch repairs.

The pipeline maximum operating pressure (MAOP) had been downrated to 44 bar in 1992 in compliance with a Government edict. Following the inspection a fitness-for-purpose study was conducted to provide Bulgargaz with a strategy to increase the MAOP to 55 bar. The most important factors to influence the future integrity of the pipeline were the external corrosion and dents.

According to ANSI/ASME B31.G 58 of the 3 926 external corrosion features required repair. However, using a more appropriate assessment method only 6 features required repair to ensure the immediate integrity of the pipeline. An additional assessment identified that only 9 of the other defects required further investigation.

To ensure the longer term integrity of the pipeline it was necessary to determine the effectiveness of the cathodic protection (CP) system, and upgrade it where appropriate to ensure that future corrosion growth rates were reduced to as low a level as possible.

The efficiency of the CP system had been reduced as result of decreased budgets and damage/theft. Advice was required on the best methods to improve CP protection at limited cost. Field investigations were conducted, on the basis of the inspection findings (using both ‘ON’ and ‘OFF’ potentials) to identify areas where the pipeline was not sufficiently protected by the cathodic protection system and to recommend remedial measures where appropriate. During the field study, an area was identified where the cathodic protection system was not protecting the pipeline to the required

levels; following the installation of a temporary ground bed and power supply, protection levels on the pipeline improved to the required level.
Thus Bulgargaz were provided with a strategy for the rehabilitation and future operation of the Beglezh to Novy Iskar pipeline. Furthermore, a plan (based on the ASPIRE findings) was provided for the safe rehabilitation of the remainder of the pipeline system when funds were available.

9. ASSESSING RISK TO THE PUBLIC

All industrial activities including the transmission of hazardous materials by high pressure pipelines involves some measure of risk, e.g., risk of personal injury or death, pollution, loss of pipeline product or loss of throughput revenue. This risk can never be entirely eliminated and failures do occur from time to time, from a variety of causes, on transmission pipelines around the world.

Risk associated with pipelines is defined as the likelihood of a person becoming a casualty, as a result of a pipeline failure.

RISK = FAILURE FREQUENCY x FAILURE CONSEQUENCES

For a high pressure gas transmission pipeline the failures of most concern are those resulting in a break (rupture) with escaping gas igniting and giving rise to a thermal radiation hazard to the surrounding population. The risk to the population living in the vicinity of a pipeline is defined in terms of both individual and societal risk:

(i) Individual risk is defined as the risk of a person at a particular location becoming a casualty.
(ii) Societal risk is defined as the relationship between the frequency of an incident and the number of casualties that may result.

Although design codes do recognise the potential hazard of pipelines, e.g., for onshore gas pipelines account is taken of this hazard by restricting the operating pressure and stress level (design factor) on the basis of population density and in some codes by specifying minimum proximity requirements, these restrictions are not risk based.

Indeed, we have been involved in conducting risk assessments at several sites along a high pressure gas pipeline designed for operation at a design factor of 0.72 in a remote jungle area. During the construction of the pipeline a wide route through the jungle area was cleared. New developments (commercial and domestic buildings and roads) have now started to be built on the cleared land (Figure 15). As a result of the potential increase in the population density at these locations, the ANSI/ASME B31.8 location classification of the pipeline would change resulting in a requirement to lower the operating pressure.

For each of the sites studied the likelihood of failure from different failure causes, the corresponding consequences of failure and the resulting risk to the surrounding population were determined utilising proven and published methods (14). The reduction in risk associated with (i) lowering the operating pressure (in accordance with the requirements of ANSI/ASME B31.8) and (ii) alternative risk reduction measures (i.e., increased wall thickness, installation of concrete slabbing above the pipeline, and/or the use of pipeline marker tapes) was quantified (Figures 16 a and b). At all the sites studied it was demonstrated that reducing the operating pressure in accordance with the code requirements did not result in an acceptable level of risk (14). Consequently alternative (and less expensive) measures were recommended which reduced the risk to acceptable levels.

10. UPRATING PIPELINES (15)

There is a world-wide trend to consider uprating in-service pipelines. For example, increased reserves, production potential or customer demand can indicate that the existing capacity of a pipeline in inadequate; uprating the pipeline (particularly from 0.72 to 0.80 design factor) is a cost-effective method which can allow the capacity to be increased.

There is limited guidance in current pipeline codes (particularly relating to uprating above 0.72 design factor). As a pre-requisite to uprating existing pipelines, the codes generally specify pressure re-testing to a higher level which maintains the original test/operating level ratio, However, this approach has severe technical and economic limitations.

There is an alternative safe and cost-effective approach to uprating (15), which is based on intelligent pig inspection, assessment and risk analysis.

The first step of the risk analysis is to identify all the credible failure modes, e.g., internal/external corrosion, ground movement, upheaval buckling, third party damage, etc and to determine the respective failure probabilities. Standard statistical techniques can be used to combine the individual failure probabilities into an overall pipeline failure probability. The increase in the risk of failure, during both ‘gassing up’ (the time at which the pipeline pressure is increased) and subsequent operation of the pipeline, can then be determined (Figures 17a and b).

A route survey must be conducted to identify all occupied buildings in the vicinity of the pipeline that could be affected by failure of the pipeline at the uprated pressure (Figure 18). The associated individual and societal risks should be determined using an industry standard methodology (14) and compared against acceptable risk levels. If necessary, alternative risk reduction measures should also be evaluated and implemented as appropriate.

In addition to the above, the integrity of all plant and fittings in the pipeline must be determined at the uprated pressure and the maintenance procedures reviewed to identify any changes that are needed.

The alternative approach has been successfully utilised to justify uprating on and offshore gas pipelines in the UK, North Sea, S E Asia, Middle East and South America.

For a typical 36 inch diameter gas transmission pipeline, uprating from 0.72 to 0.80 design factor, provides an additional $20 million throughput per year.

11. LIFE EXTENSION OF A PIPELINE SYSTEM (16)

This final example demonstrates the benefits, in terms of life extension, of an extensive programme of maintenance and rehabilitation on an onshore gas pipeline system in South America.

A five year maintenance and rehabilitation programme (involving intelligent pigging, pipeline section replacement, welded shell repair, re-coating and improvements to the cathodic protection (CP) system) was conducted on a 6,600 km gas transmission system. Subsequently, a study was conducted to determine the benefits associated with the maintenance and rehabilitation programme in terms of the remaining useful life of the system.

Risk based methods were utilised to predict:

(i) the future external corrosion growth rates (associated with unprotected areas of the pipeline (due to inadequate CP) and fully protected areas),
(ii) the development of new areas of external corrosion with time,
(iii) the relationship between the number of future repairs and time, and
(iv) the effects of upgrading the CP system.

The results of the study are provided in Figure 19, which shows the predicted number of pipeline repairs as a function of time. A total of 89,000 external corrosion features will have been repaired/re-coated by the end of the year 2001 under the current maintenance plan. If the system continues to be maintained according to the standards established, then a life in excess of 100 years can be achieved. However, without the planned improvements to the CP system, then the system could become uneconomic to operate within circa 25 years.

12. CONCLUDING REMARKS

Case studies have been presented which demonstrate the benefits of utilising 'Total Pipeline Integrity' customised packages throughout the lifetime of a pipeline. 'Total Pipeline Integrity' is based on PII's 30 years research and operator knowledge and the experience of conducting almost 300 consultancies for over 50 clients in over 30 countries. Based on this experience 'Total Pipeline Integrity' offers 'industry best practice' in pipeline maintenance and rehabilitation.

Customised packages can vary from (i) a single service (e.g. conducting risk calculations) to (ii) providing a complete rehabilitation service (risk assessment, cleaning, inspection (internal and above ground), excavations, repairs, re-coating, GPS, training, O&M manuals, major incident planning, integrity management software, certification etc.).

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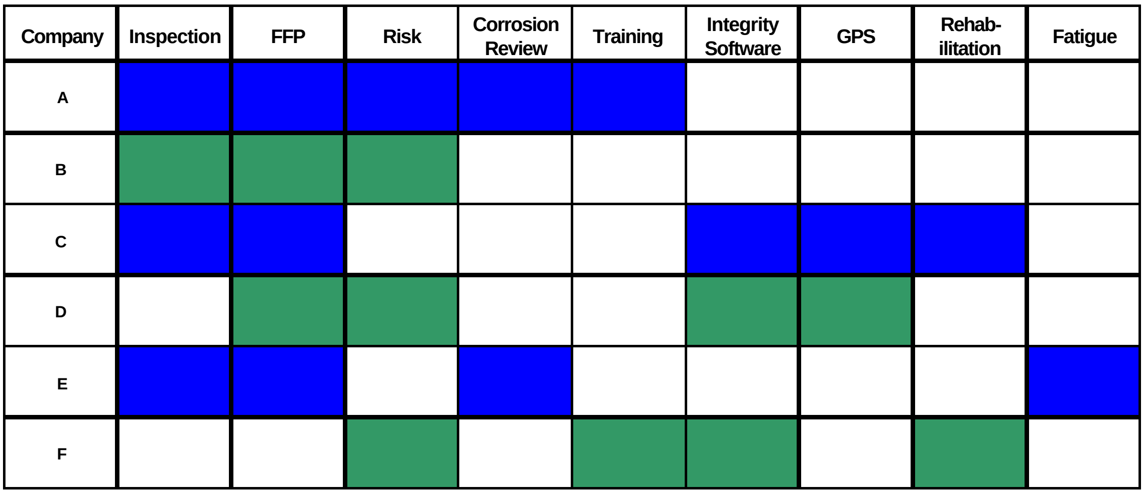


Fig. 1 - Examples of Total Pipeline Integrity Packages

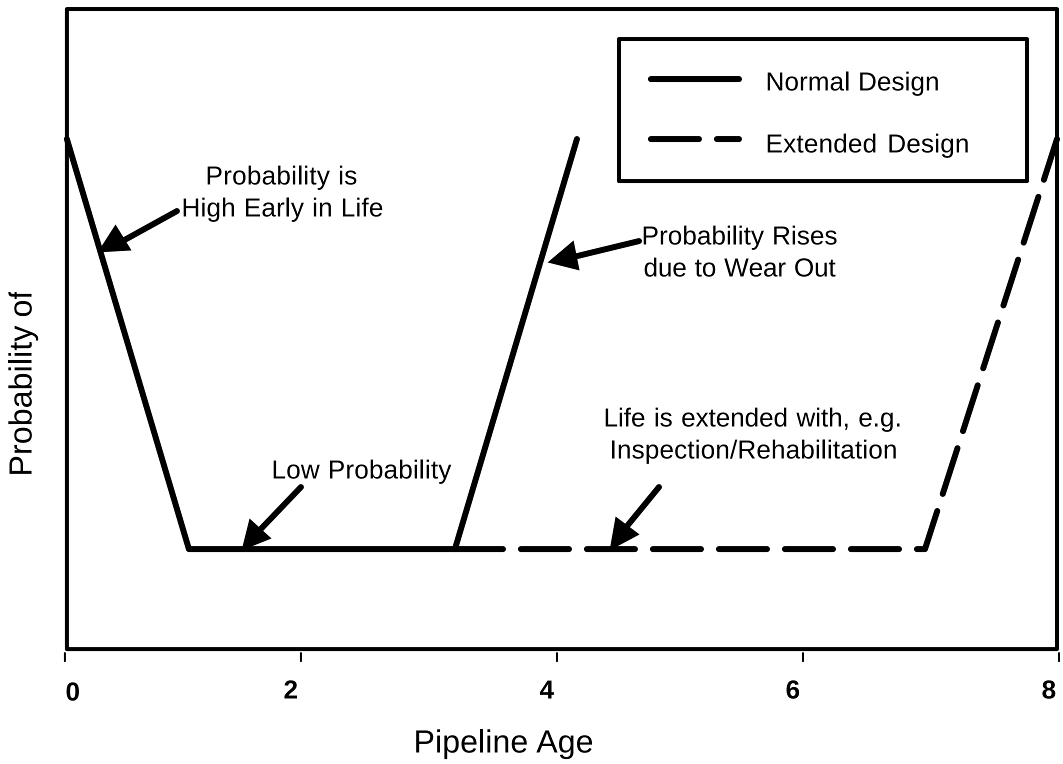


Fig 2 'Bath Tub' Failure Curve

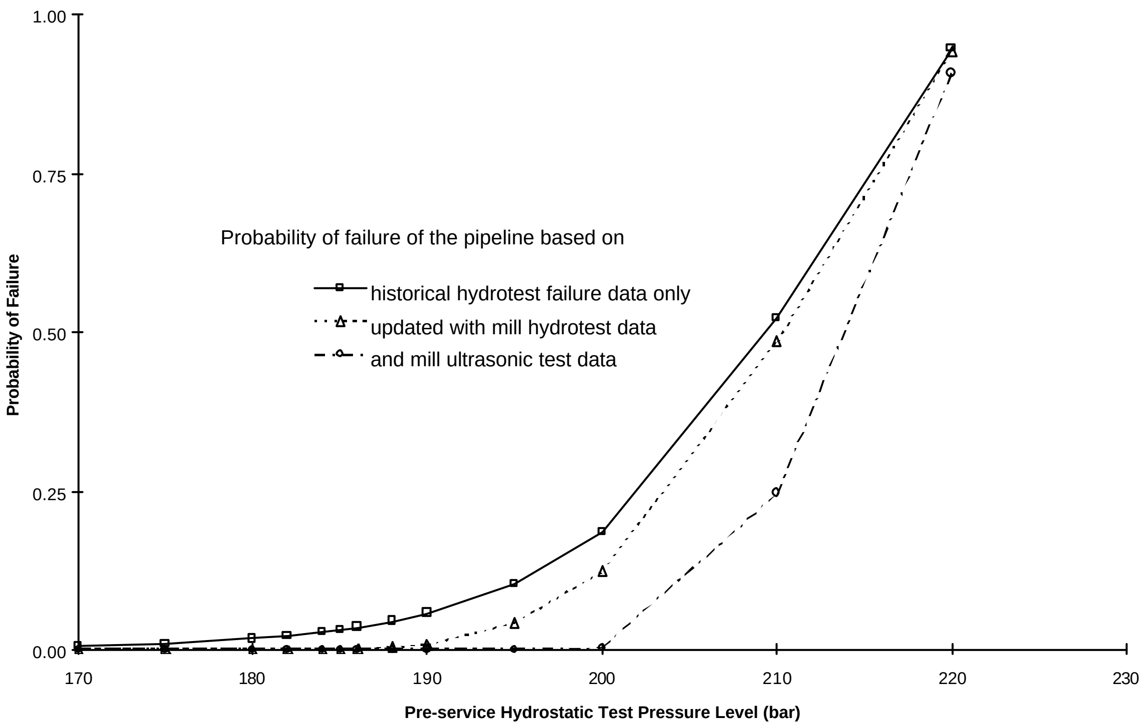


Fig 3 Relationship Between the Probability of Failure and the Hydrotest Pressure

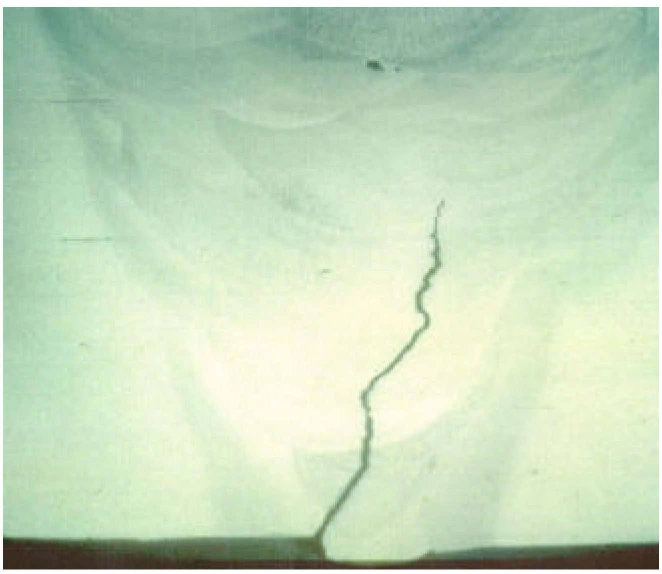


Fig. 4 - Girth Weld **Fig. 5 - Girth Weld Crack**

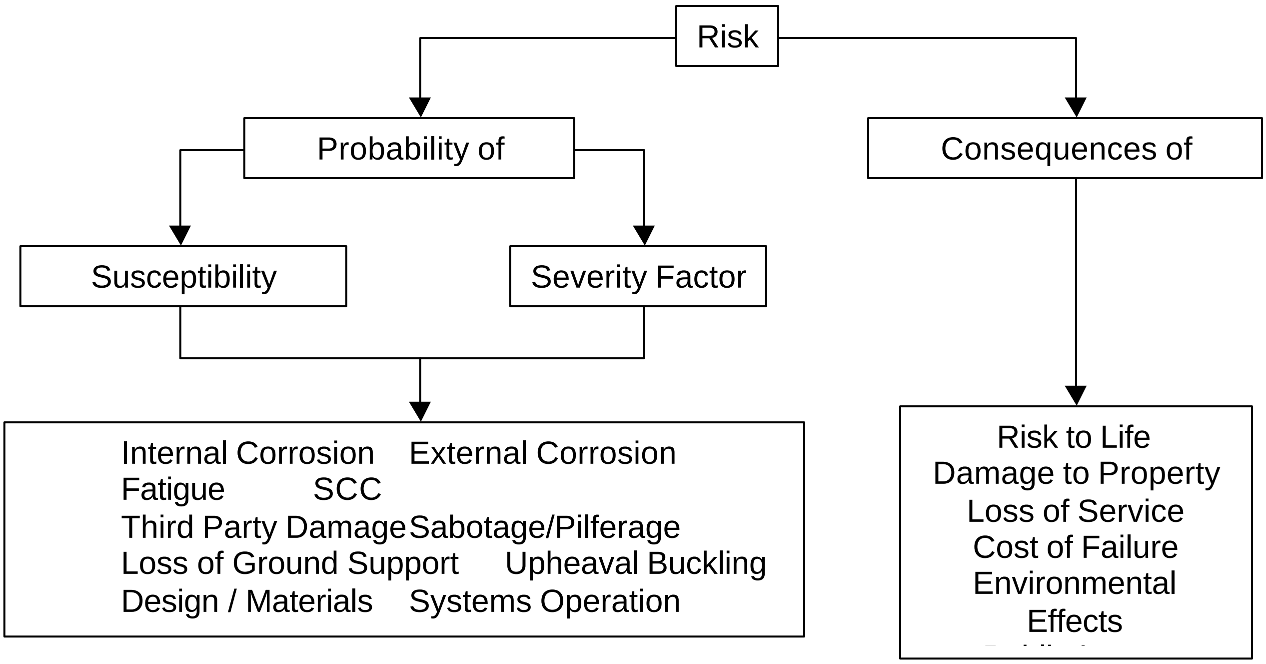


Fig 6 Pipeline Prioritisation Methodology Utilised in ASPIRE

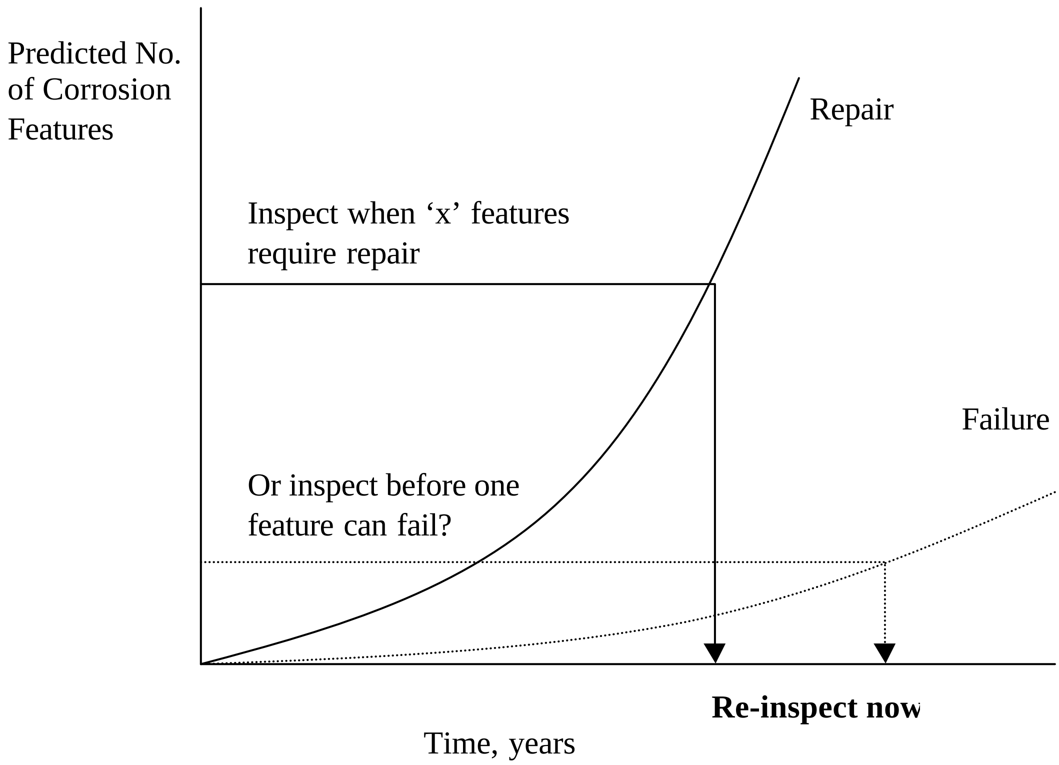


Fig 7a Relationship Between the Number of Repairs and/or Failures and Time

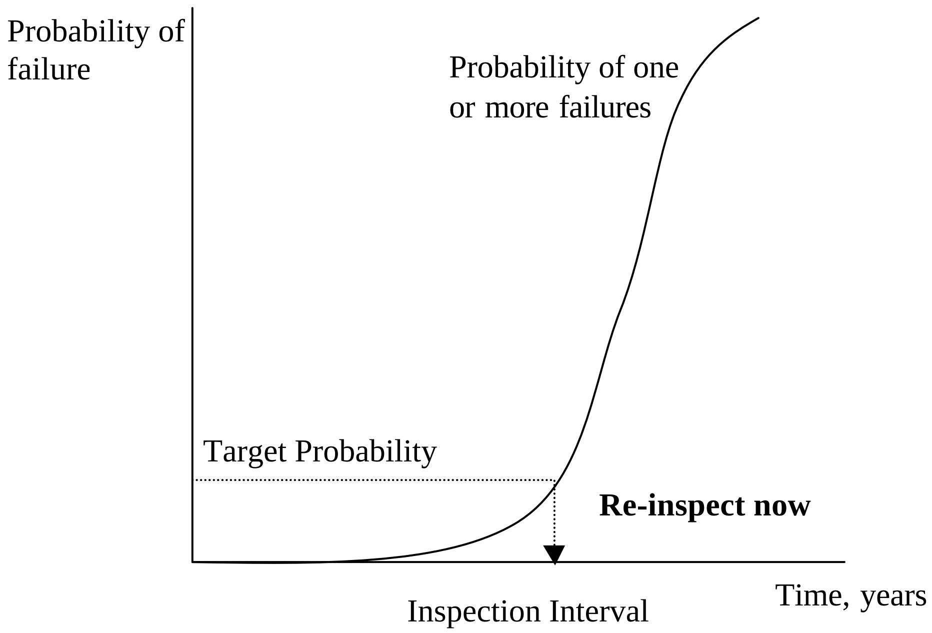


Fig 7b Relationship Between the Probability of Failure and Time

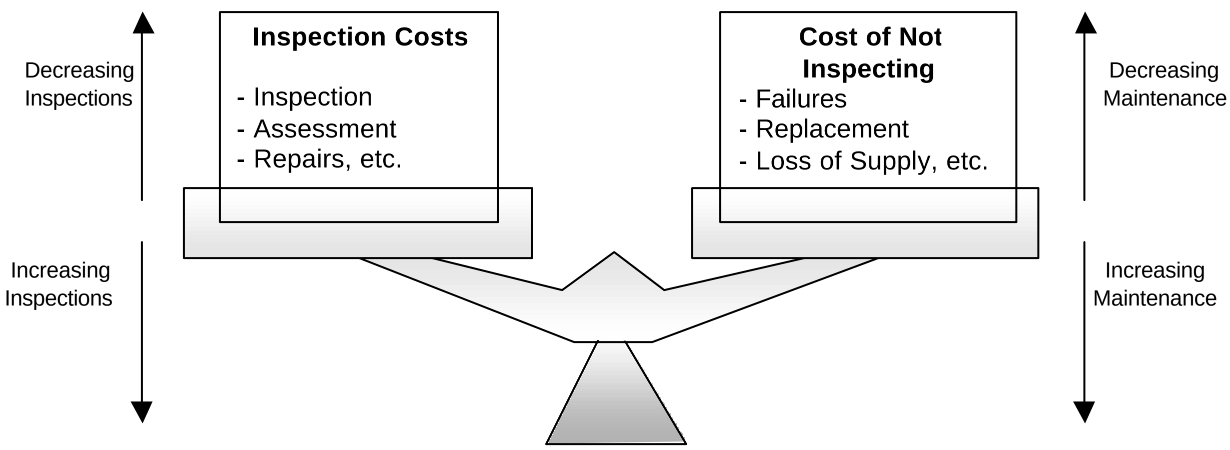


Fig 8a Should I inspect ? - Cost benefit approach

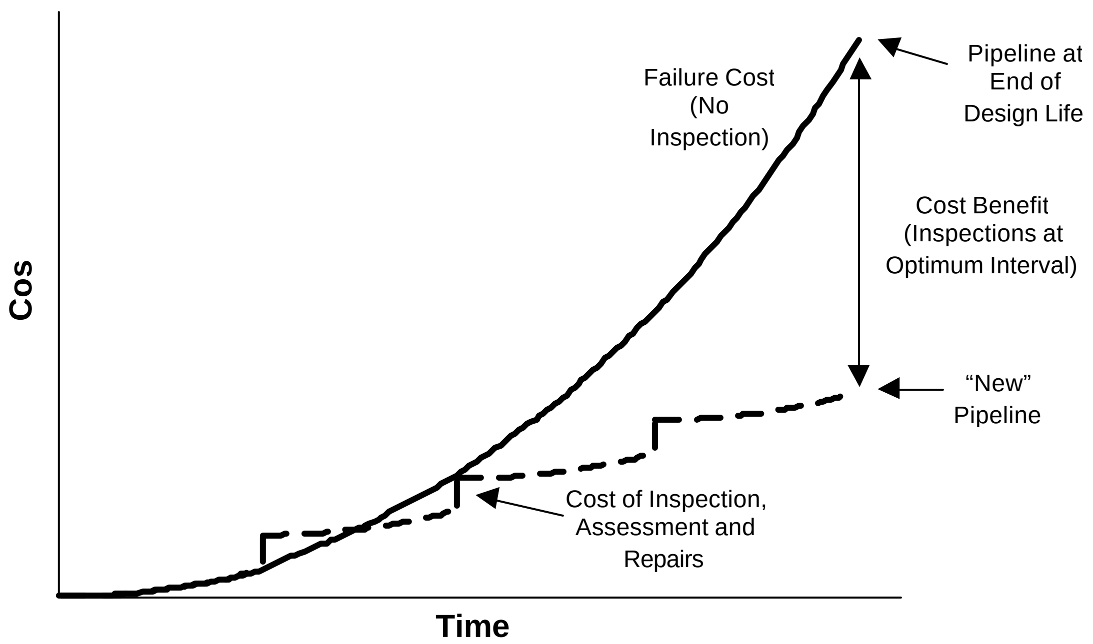


Fig 8b How often to inspect - Cost benefit approach

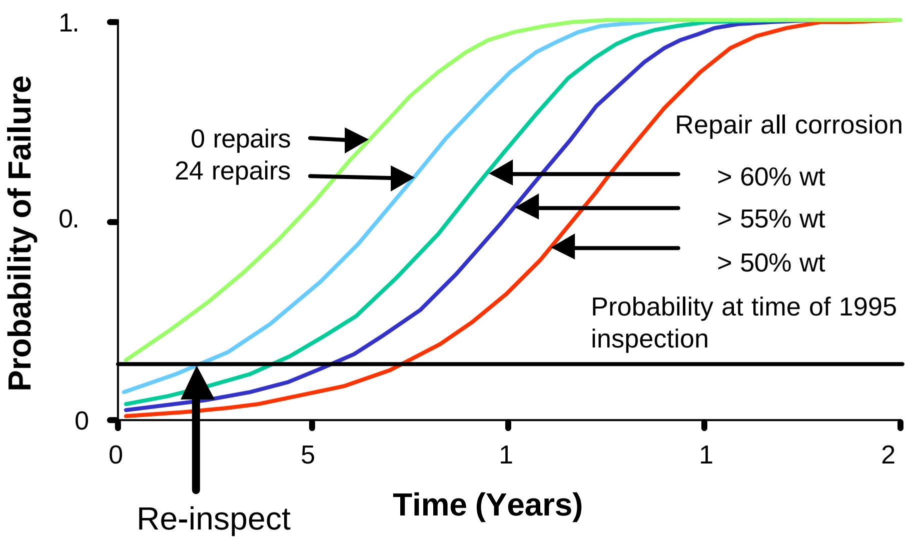


Fig 9 Relationship Between Probability of Failure and Time : Benefit of Conducting Repairs

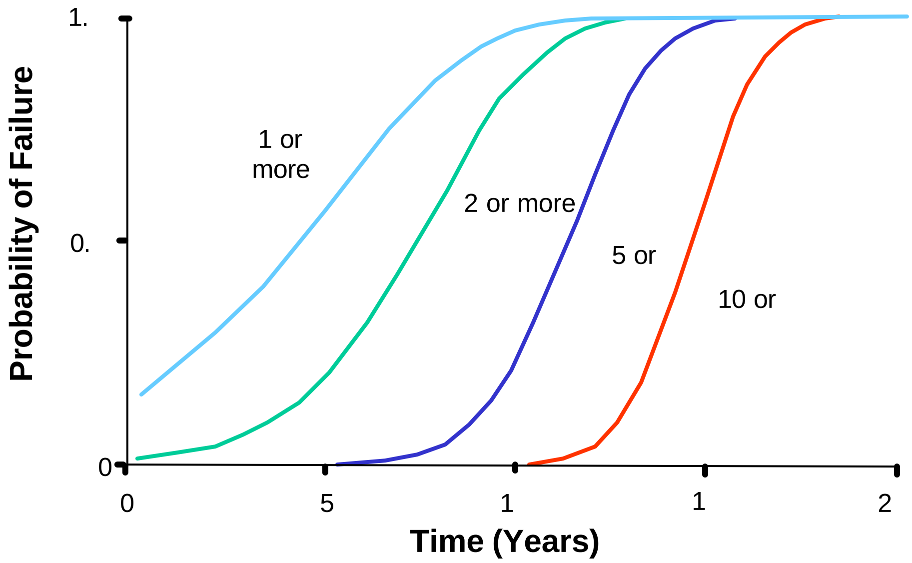


Fig 10 Probability of “Many” Failures vs. Time

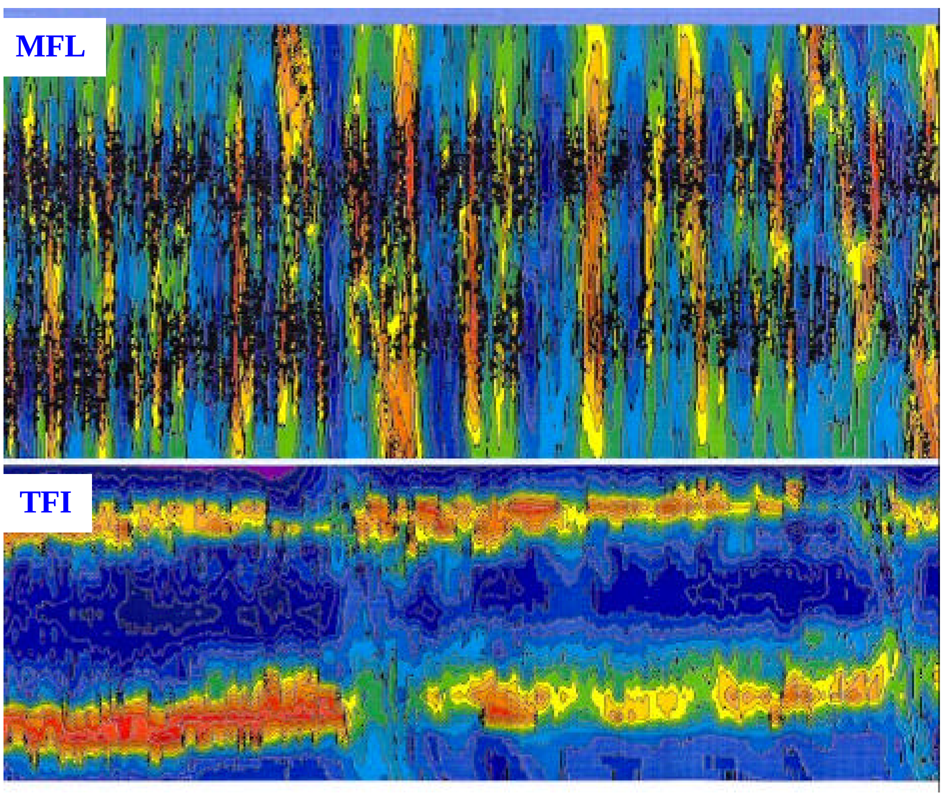


Fig 11 Comparison of MFL and TFI Inspection Data at an Area of Corrosion

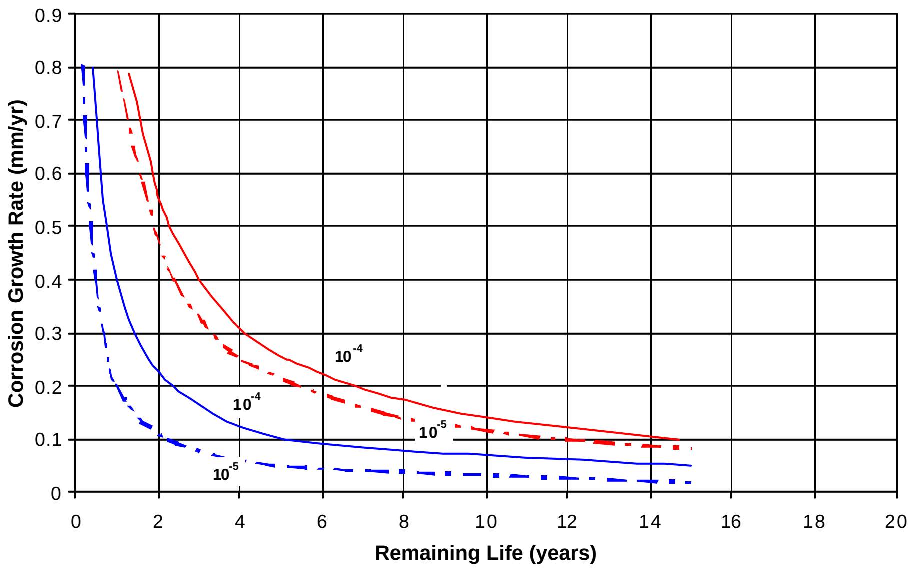


Fig 12 Relating Risk to Remaining Life, Operating Pressure and Corrosion Growth Rates

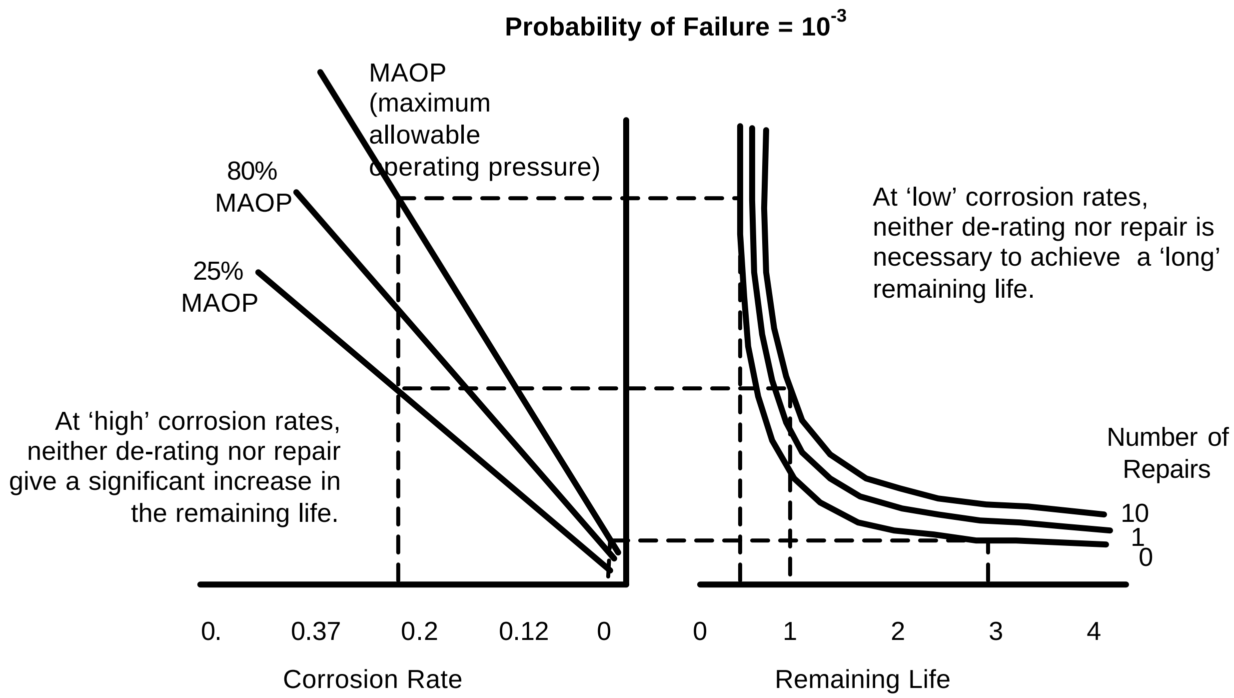


Fig 13 Probabilistic assessment provides the technical basis for future operating strategies

Before study **After study**

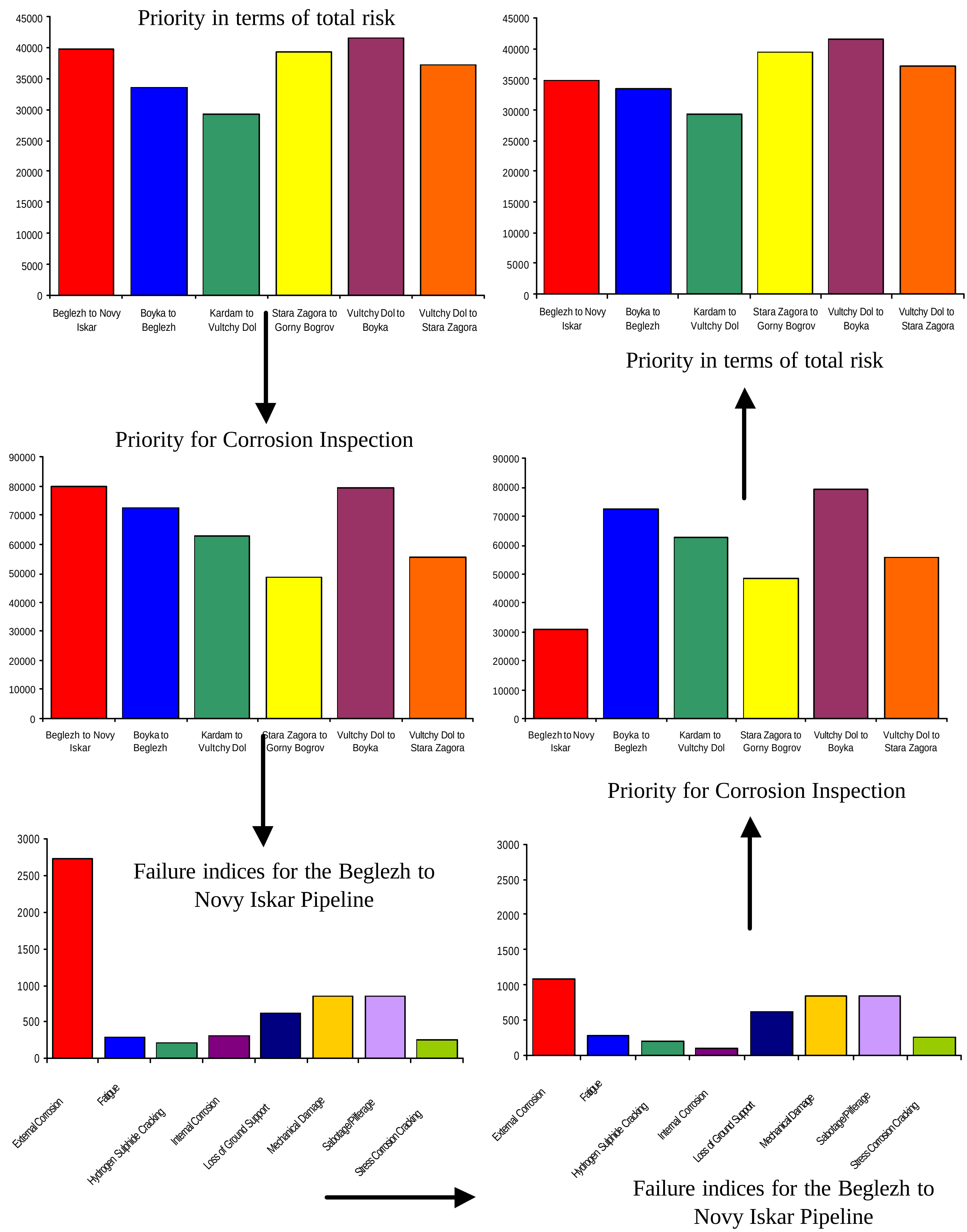


Fig 14 - Planning the Rehabilitation of the Bulgargaz Pipeline System (using ASPIRE risk software)

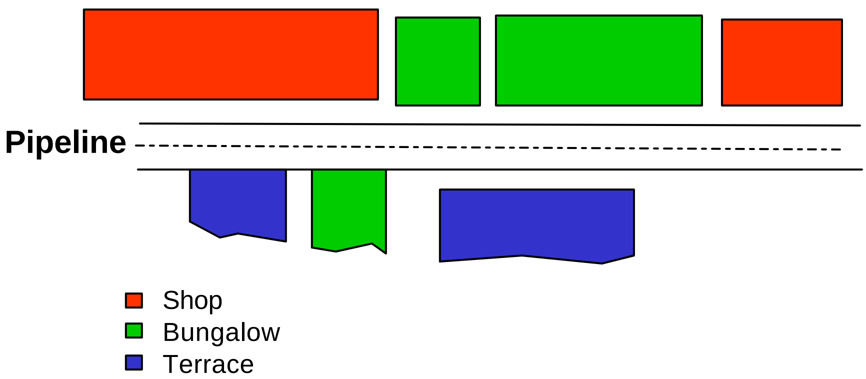
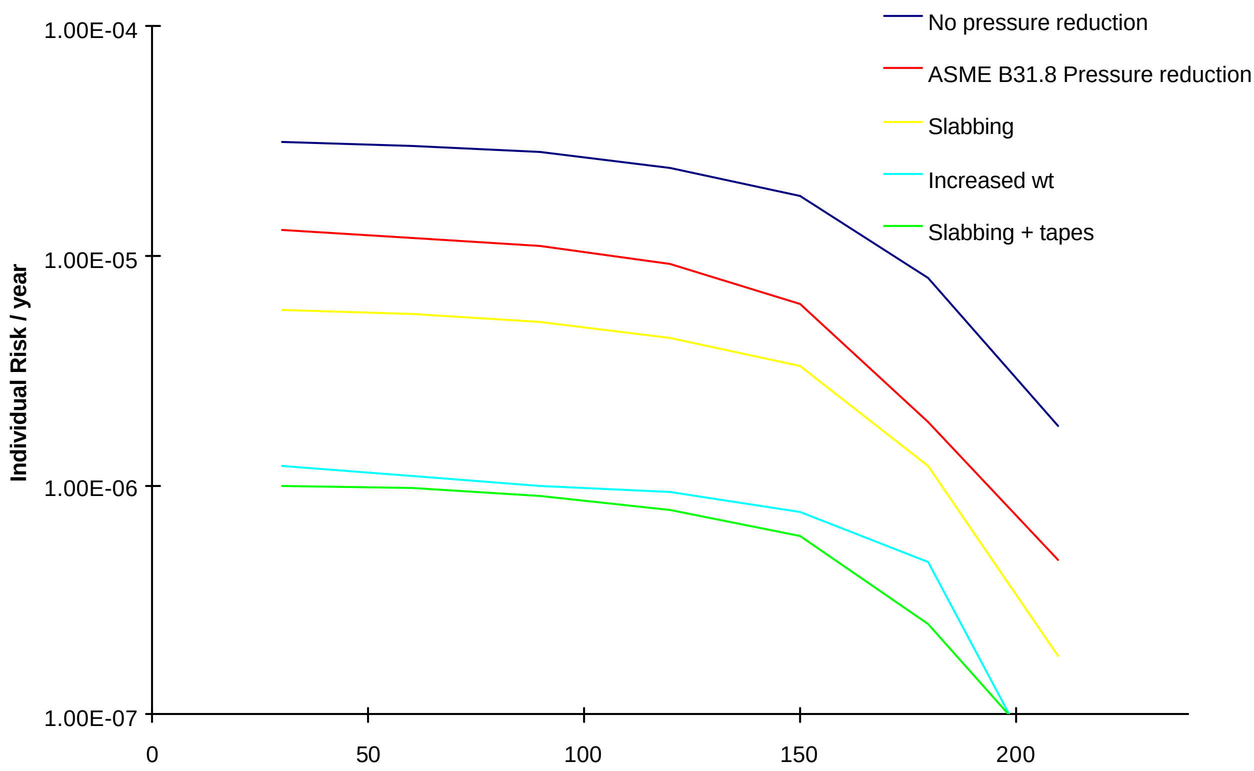


Fig 15 Example of a Site where a New Development has been Constructed Adjacent to a High Pressure Gas Pipeline



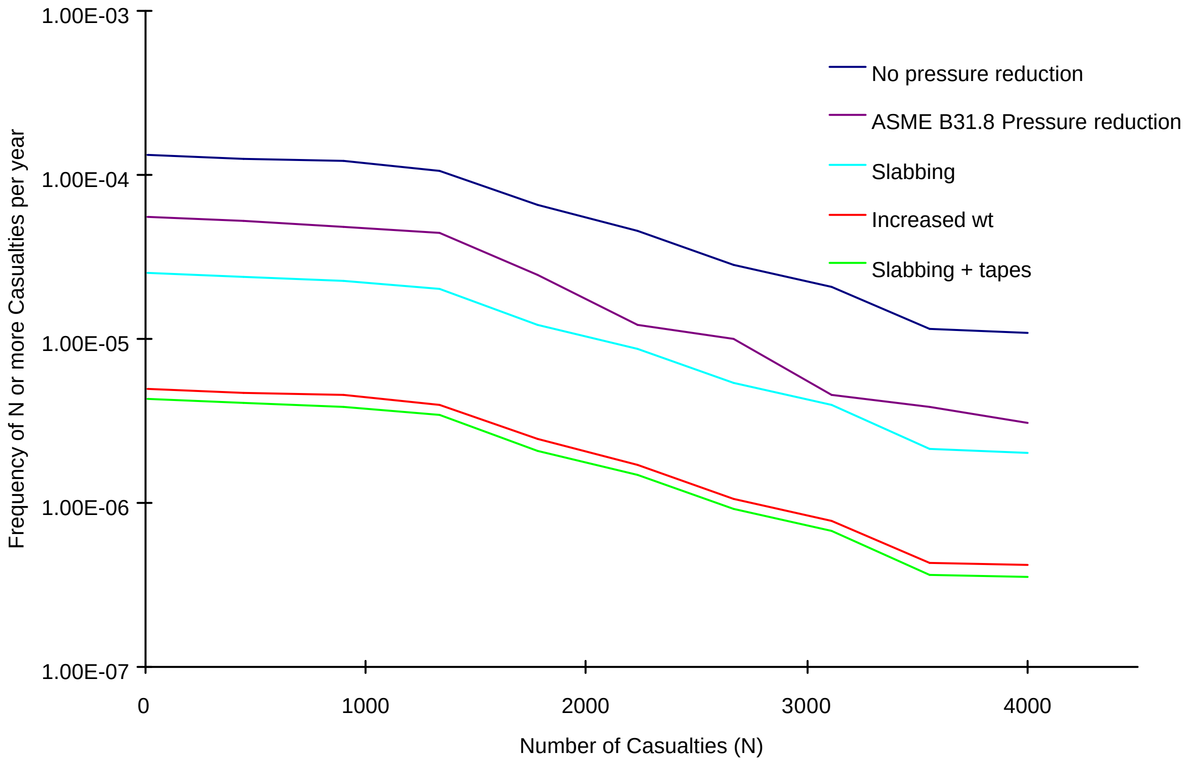
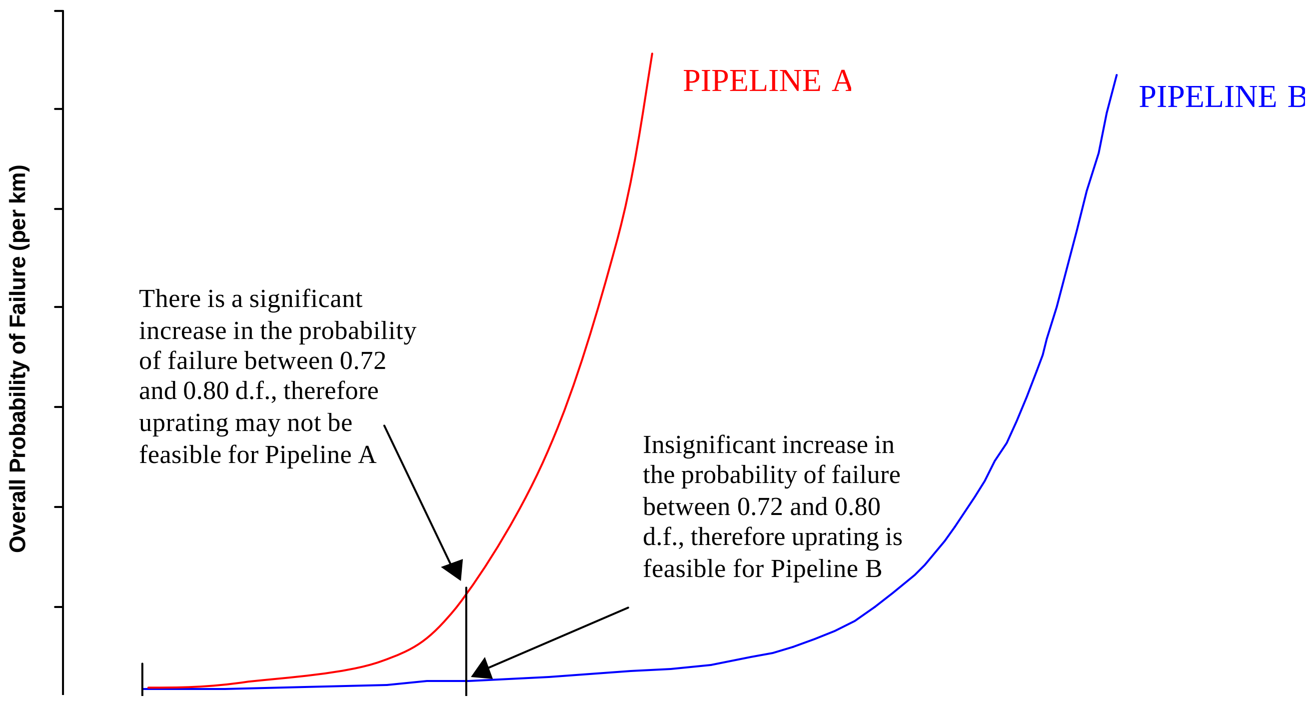


Fig 16b Reduction in Societal Risk Associated with a Reduced Pressure and Alternative Risk Reduction Measures



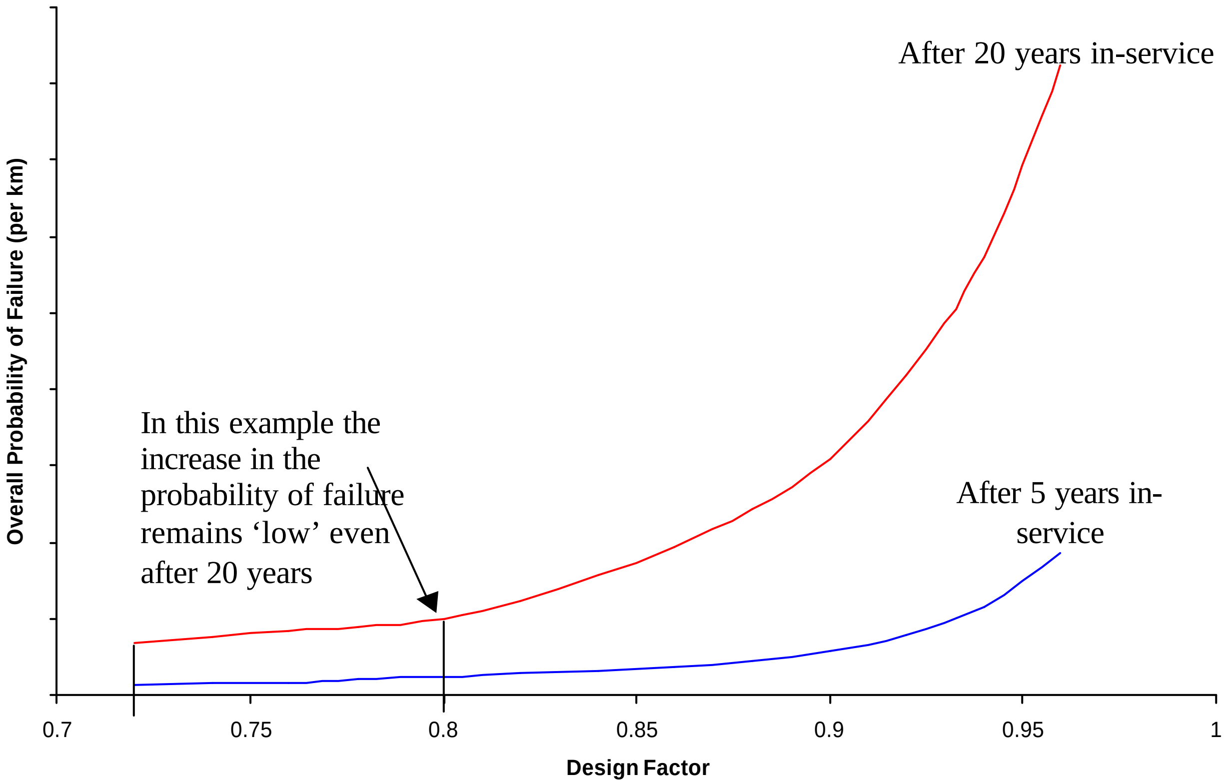
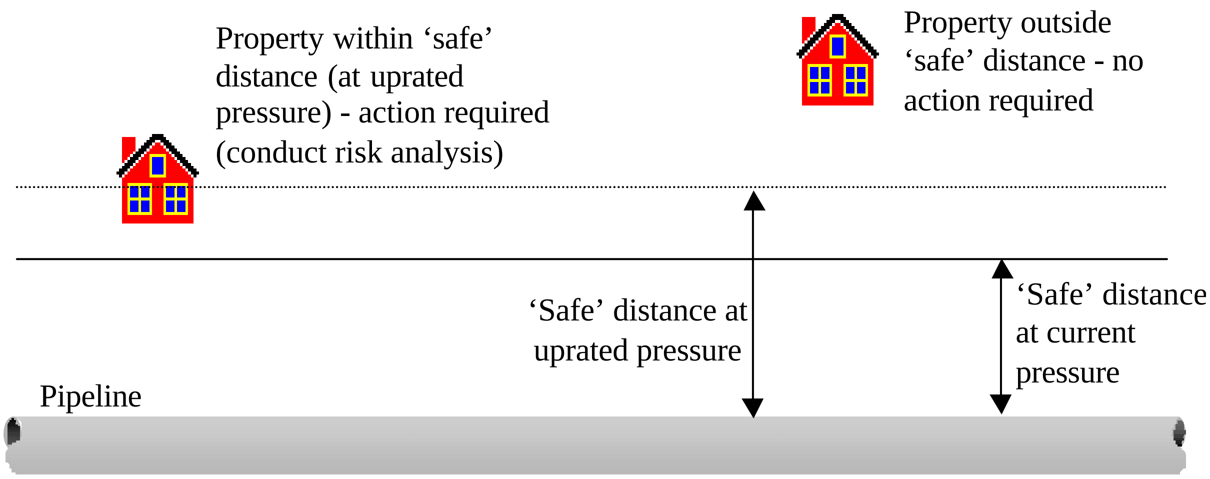


Fig 17b Probability of Failure During Continued Operation



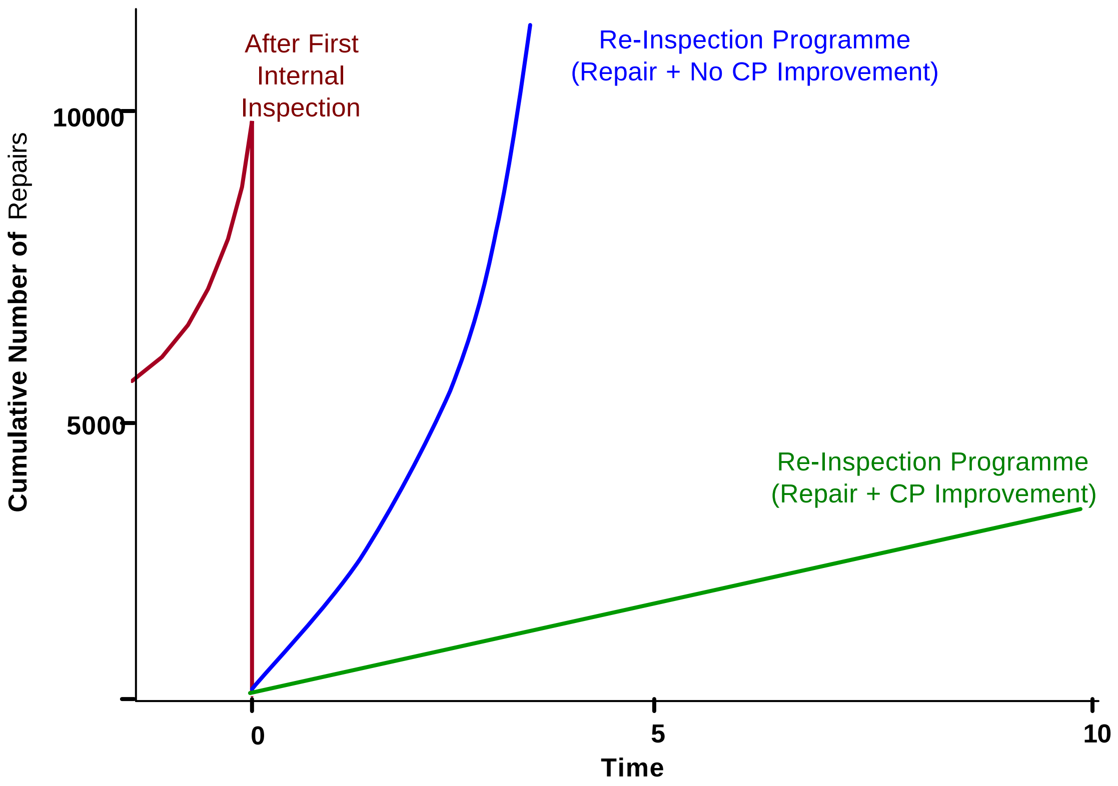


Fig 19 Predicted Number of Pipeline Repairs as a Function of Time