PIPELINE FRACTURE EXPERIENCES IN AUSTRALIA AND NORTH AMERICA

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INTRODUCTION

The likelihood of the failure of high pressure fluid pipelines due to brittle or ductile fracture behaviour has been present ever since natural gas was first shipped in long distance pipelines. However, it was not until the 1950s when a long running brittle fracture occurred in a natural gas pipeline in North America, that the pipeline industry began to carry out research into the phenomenon. This failure resulted in the establishment of the American Gas Association's Pipeline Research Committee (PRC) by pipeline owners who saw the need to carry out fundamental and applied research into a hitherto unexpected failure mechanism of high pressure natural gas pipelines. The work carried out under the direction of PRC provided designers with new tools to prevent brittle failure and to minimise the effects of ductile failure. In parallel with the work done on steel toughness, researchers had to develop models to represent the decompression characteristics of high pressure natural gas escaping from a propagating crack. It was only when both sets of models were combined, that researchers and pipeline designers began to understand the failure mechanism. These aspects are just as important in the design of today's pipelines.

Australian natural gas pipelines were built after most of the results of this early research were available to designers and steel pipe manufacturers. As a result, pipelines were designed with adequate fracture toughness to prevent brittle long running failures, although there is evidence that some pipelines built in the late 1960s may not have had adequate toughness to arrest ductile failure and to minimise fracture propagation to within one or two pipe lengths. However, the very few propagating failures recorded in Australia, and their minimal effects is testament to the fact that all Australian pipelines built since the mid 1970s, have been designed with appropriate regard to fracture control.

This paper will provide an overview of the research work carried out to arrive at the design tools to analyse and prevent, as much as possible, both initiation and propagation of brittle and ductile failures of pipelines. The paper will also review fracture initiation mechanisms and a sample of the pipeline failures in Australia and North America to provide some practical background to the analytical methods used in pipeline design and steel specification.

The Australian pipeline industry is currently addressing the management of risk in the design and operation of natural gas pipelines. An important aspect of the management of risk is an assessment of the consequences of a pipeline failure; an understanding of fracture control of pipeline steels is essential to this assessment.

BACKGROUND TO RESEARCH IN BRITTLE AND DUCTILE FAILURE

One of the first acts of the newly created Pipeline Research Committee in 1958 was to commission the Battelle Memorial Laboratories in Columbus, Ohio, to perform research on line pipe steel, including full scale testing of sections of pipe to determine the parameters associated with long running brittle failure of high pressure natural gas pipelines. The first reports that were prepared by Battelle included:

Table 1: Major reports on fracture control by the Pipeline Research Committee

Report Name	Year Completed
Investigation of Notch Toughness of Pipe Steels (ARF)	1956
Conditions Affecting Crack Initiation in Line Pipe	1957
Conditions Affecting Crack Initiation in LP II	1958
Analysis of Impact-Test Results	1959
Research on Conditions Affecting Crack Initiation in LP	1960
Field Investigation Fracture Characteristics in Service	1961

The work by PRC resulted in the use of the drop weight tear test (DWTT) which was designed to ensure that all new pipelines were manufactured from steel which would not support brittle failure. Much of this research work indicated that many pipelines in North America would fail in the brittle mode, so the members of the PRC who were pipeline owners were very sensitive about the results of the studies. Consequently, much of the data and results were never published outside the PRC.

In the late 1960s it became evident that brittle failure was not the only cause of a propagating failure, so work was initiated by PRC to investigate this other mode of failure – ductile – and to determine the methods by which pipeline designers could prevent its initiation and propagation. This work culminated in the early 1970s, but it was not until the mid 1970s that a definitive paper was published by W. A. Maxey, entitled *Fracture Initiation, Propagation and Arrest*, which was presented to the Fifth Symposium on Line Pipe Research (1974). This paper represented a summary of the work done under the auspices of PRC for nearly two decades. This paper is still relevant.

However, the threat of propagating ductile fracture still remained and methods of controlling this type of failure had to be determined, particularly in the light of the use of higher strength steels for large diameter pipelines. So work continued in two streams – one to develop analytical methods for preventing pipeline cracking or rupture, i.e. initiation, and another to prevent the propagation of the crack.

The early PRC work concentrated on the development of technique to predict the correlation between flaw sizes and steel toughness to determine the critical flaw size which would result in a rupture, rather than a leak. Some work was also done in Battelle on the development of empirical relationships between steel toughness and its ability to arrest a propagating failure. However, the majority of work on fracture arrest was carried out in Europe, by British Gas, the European Pipeline Research Group (EPRG) and steel manufacturers. This has resulted in an array of empirical formulae which, while they do not provide consistent results, remain the best guides for a pipeline designer.

DEFINITIONS

Before launching into the formulae used by today's pipeline engineers and designers to control fracture initiation and propagation, it is useful to define fracture initiation and propagation as well as some of the relevant factors and terminology. The nomenclature used in the fracture control formulae are defined after the presentation of the formulae themselves.

Fracture initiation is the process whereby a defect grows via any number of driving forces to the point where it penetrates the pipe wall thickness and produces a leak or rupture.
Fracture propagation is the rapid growth of a fracture once it has initiated or penetrated the pipeline wall thickness.
Critical flaw size is the maximum flaw that a pipe segment can tolerate before the flaw penetrates the wall thickness or extends axially or radially along the pipe.
Charpy V-notch test (CVN) is a test used to determine toughness of steel used in the manufacture of pipe. The CVN is used to estimate fracture initiation toughness for most pipeline operating conditions.
Cyclic softening[1] - An increase in the fraction of inelastic strain in a cycle, due to changes in the microstructure as a function of the accumulated microplastic strain with each pressure cycle on the pipeline.
Drop-weight-tear test (DWTT) is another test used to determine the toughness of steel used in the manufacture of pipe. DWTT is used to determine the FPTT of a pipeline steel.
Flow stress of a material is approximately equal to yield stress plus 68.9 MPa (10 ksi). It accounts for strain-hardening in terms of an equivalent elastic-plastic material by means of a single strength parameter.
Fracture initiation tolerance is a measure of the pipes ability to resist penetration by a defect.
Fracture initiation toughness is the resistance of a material to initial stable and unstable crack growth.
Fracture initiation transition temperature (FITT) is the temperature above which the fracture initiation mode is ductile and below which the initiation mode is brittle.
Fracture propagation transition temperature (FPTT) is the temperature at which propagating fractures undergo a transition from ductile to brittle behaviour with decreasing temperatures. It is expressed as the DWTT 85% shear transition temperature of pipeline steel.
Fracture propagation resistance determines whether a rupture will arrest or continue to propagate along the pipe length.
Macrocrack - A crack whose driving force is above the linear elastic threshold for stress corrosion cracking.
Microcrack - A crack whose driving force is below the linear elastic threshold for stress corrosion cracking or whose growth is dominated by the local stress field and therefore is. largely independent of its size
Upper-shelf or shelf energy is the energy value at 100% shear area for DWTT or CVN specimen.

INITIATION MECHANISMS

Fractures can initiate at most any service stress level from defects introduced into the pipe. These defects can be introduced by outside force, corrosion, material defects, operating conditions or errors and environmental conditions. Fractures occur when the stresses acting on a defect overcome the fracture initiation tolerance of the pipeline and reach critical size for the pipeline physical and material properties and operating condition. The stress that causes a defect to grow is the summation of all stresses acting perpendicular to the defect.

Axially oriented defects tend to dominate as the pipeline hoop stress is generally the largest contributor to the combined stress of a pipeline. Circumferential defects require the longitudinal stresses to exceed the hoop stress and are typically associated with additional loading of the pipeline due to environmental conditions or outside forces. These situations can impose a longitudinal force on the pipeline that when combined with any existing bending and longitudinal stress could cause stresses sufficiently higher than the hoop stress such that a circumferentially oriented defect could become critical.

Outside Force

Fracture initiation mechanisms associated with an outside force incident causing a defect can be typically categorised as mechanical damage or soil movement. In Australia outside forces account for over 78% of all pipeline incidents. By comparison the figure is approximately 40% for the United States, 12% for Canada and 54% for Europe. However, the figure for the US can be misleading due to the reporting requirements of the US Department of Transportation (DOT)[A] - Office of Pipeline Safety (OPS).

Outside force incidents causing pipeline defects are usually associated with mechanical damage from excavation equipment operated by the pipeline operating company employees or third party contractors. When struck by construction equipment, the defect that results constitutes a severe stress concentration and, because it is created suddenly, can subject the pipe steel to a high rate of strain. The resultant defect is typically a dent, gouge, or dent with a gouge[2] and may or may not immediately penetrate through the wall thickness and cause leakage. Occasionally pipelines are punctured via mechanical damage from the bucket of an excavator/backhoe or a blade from a ripper. These punctures can result in fractures that often catch fire due to the internal combustion engines driving the machinery.

British Gas[3] has concluded that wall thickness is the main factor to prevent pipeline puncture due to outside force. The British Gas investigations have shown that wall thicknesses greater than 9.5 mm (0.375”) prevent puncture from excavation equipment typically used in the UK. Wall thicknesses greater than 9.5 mm have subsequently been successful at preventing punctures due to mechanical damage on in service pipelines.

This does not hold true for North America. The PRC sponsored a report on *Line Pipe Resistance to Outside Force*[4] where in addition to reviewing DOT-OPS 30-day reports, a survey of PRC-member companies identified an additional 385 non-reportable incidents of mechanical damage. The analysis of the data show no trend evident with regard to wall thickness, hoop stress, failure stress or SMYS. Leaks occurred at wall thicknesses of 9.5 mm (0.375”), hoop stresses from 0%-72% of SMYS and yield strengths of 33 - 65 ksi. Additionally, wall thicknesses up to 17.5 mm (0.688”) have not prevented leaks and ruptures in North America due to mechanical damage.

Relying solely on increasing the wall thickness would appear not to provide the level of fracture initiation resistance one might anticipate from the British Gas literature on North American pipelines. An unfavourable result of using more costly and less efficient line pipe for pipelines in North America and other countries relying on the British Gas work could result without assessing the particular characteristics of its own pipeline infrastructure. The effect would be to limit the use of higher strength steels with higher fracture toughness and lower transition temperatures and greatly reduce the economic viability of a pipeline project.

Soil movement associated with earthquakes, landslides and waterway washouts is another outside force that can cause a pipeline defect or fracture. Differential settlement, landslides and soil liquefaction from earthquakes are familiar failure mechanisms to

[A] Incidents that incurred costs of more than $50,000 and injury or fatality occurred, or in the opinion of the operator was a potentially serious event must be reported to the DOT-OPS within 30 days pipeline operators along the west coast of the United States and the Pacific Rim. This type of activity can often cause circumferential failures in pipelines, especially in older pipeline welds.

The potential for settlement is a force that can be easily overlooked in the design of pipelines which can lead to stress concentrations detrimental to the integrity of the pipeline system. Slides and washouts can cause large bending stresses due to the suspension of long lengths of pipeline, impacts from debris and physical displacement of the pipeline from its installed position. The stress associated with these activities can easily exceed a pipeline yield and ultimate strength.

Corrosion

Corrosion is a fracture initiation mechanism responsible for a number of pipeline ruptures world wide. Corrosion mechanisms contributing to the fracture of pipelines can be categorised as internal corrosion, external corrosion and stress corrosion cracking. Although routine smart pigging and a properly engineered, installed and maintained cathodic protection (CP) system can alleviate much of the risk of failure do to internal and external corrosion respectively, there are many thousands of kilometres of pipelines world wide that are not piggable and ensuring adequate CP coverage to an entire pipeline system takes diligent attention by the pipeline operator and a detailed corrosion control plan.

Internal corrosion has many drivers; microbial action, carbonic or sulphuric acid formation, chloride ion and erosion to name a few. Internal corrosion is most often associated with gathering systems, wet and sour service pipelines. It can be tremendously fast acting with instances were wall thicknesses of approximately 4.0 mm being consumed in less than one year in cases of severe microbial and chloride ion action. In general the corrosion associated with internal corrosion causes pitting and flaws that when they reach critical size most often leak versus rupture. However, troughing is another common form of internal corrosion which can sufficiently lower the fracture propagation resistance of the pipeline to where a leak, the result of a single pit, can result in a running ductile fracture of many metres.

Internal corrosion can be effectively treated with inhibitors, pigging and a good monitoring system using some form of corrosometer probes to measure corrosion rate. It is imperative that pipeline operators determine the internal corrosion mechanisms via laboratory testing and field testing equipment such as MIC-KITs to ensure that the proper corrosion inhibitor is being specified and applied to the pipeline. A second consideration is adequate internal coverage of the inhibitor, especially in pipelines flowing at low velocities.

External corrosion, like internal corrosion often leads to localised pitting, leaks and occasionally ruptures in pipelines. These occur due to the failure of CP current to reach the pipe wall at a defect or provide adequate current density to polarise the bare metal surface sufficiently to arrest corrosion.

As the pipeline infrastructure in Australia ages the propensity for external corrosion to become more and more of a risk to pipeline failures can increase due to failure of the pipeline and weld joint coatings, unless operators are vigilant and maintain a high level of surveillance of cathodic protection systems and apply up to date knowledge on corrosion protection engineering. In North America, where approximately 50% of the pipeline infrastructure is over 40 years old, corrosion is serious problem and continues to be the cause of many pipeline leaks. Thankfully, the majority of pipelines in Australia have had modern pipeline coatings applied and one would not expect a significant number of the problems other nations have experienced with coal tar enamels, early tapes, single and double wrapped tar and asphaltic based coatings.

Pipeline operators must ensure that they adequately assess their pipeline condition via sound CP practice and maintenance, regular close interval and DC voltage gradient surveys and internal smart pigging. From this data a responsible rehabilitation or replacement program can be initiated as appropriate to minimise the risk of a pipeline failure.

Stress corrosion cracking (SCC)is perhaps the most insidious form of corrosion - difficult to predict and detect and often leading to catastrophic failures in pipelines. The typical pattern of SCC found at failure sites is a “nest” cracks which have coalesced into a flaw that is long as compared to either its depth at failure or with the lengths of the individual microcracks prior to coalescing. SCC tends to cause pipeline ruptures under pressure unless the SCC process is stopped or the defects are removed before reaching critical size.[5]

Operating and environmental factors found to contribute to SCC are high operating temperatures (>60 degrees Celsius), cyclical loading, disbonded pipeline coating (leading to cathodic shielding), operating pressures at high percentage of SMYS, low resistivity soils, swampy, clayey or other moisture holding medium around the pipeline. It has often been found to exist in high carbon content steels and can nucleate and propagate along intergranular boundaries as well as in a transgranular fashion and in very low or very high pH soils.

Cyclic softening[6] has been postulated as the mechanism that supports long term SCC in pipelines by lowering the fracture initiation resistance of the pipeline. The theory is that for a SCC to continue to propagate without strain hardening at the crack tip, some inelastic strain dependent upon pressure cycles in the pipeline must take place reducing ductility and enhancing SCC. The cyclic straining causes changes in the microstructure which causes an increase in plastic strain per cycle and a decrease in stress at the peak stain. Thus the apparent stiffness of the steel is decreased by the effects of this softening and leads to an increment of inelastic strain.

The range of the pressure cycles that a pipeline experiences and the frequency of the cycles can greatly affect the SCC growth. Pressure changes as low as 10% of maximum stress can significantly increase the incidence of SCC on the pipeline. Pressure changes upwards of 20% tend to diminish the extent of SCC because the strain rate moves outside the window for SCC, but it can promote corrosion fatigue which is yet another fracture initiation mechanism[7].

Material Defects

Material defects can be classified as manufacturing defects and those induced by hauling, handling and construction. These defects have largely been eliminated by modern quality assurance programs and the increased focus on trained quality control personnel on hand to inspect the materials as they are being manufactured, handled and during construction.

Some of the material defects found are slivers, problems associated with longitudinal seams not meeting specification (typically toughness) and weld material matching in high strength pipelines. If a sliver is not identified at the mill, they are most often exacerbated during shot or grit blasting prior to coating and detected by the coating QC personnel. Charpy V-notch testing is used to test long seam welds for toughness and there is a paper on its limitations to be presented later on in the seminar which we look forward to with great interest. Weld metal matching for high strength thin walled pipelines is currently being research by the CRC for Welding and Joining.

Hard or "cold" spots can still be a problem for those whose pipelines manufactured prior to the introduction of controlled rolling of the plate materials used for pipe. These are localised areas of high carbon concentrations. Hard spots have not been found to be a problem in Australian pipeline steels.

Hauling, handling and transporting line pipe to job sites is always an area where damage can occur in the form of coating holidays and stress concentrators that could lead to critical flaws whilst the pipeline is in operation.

During the construction of a pipeline is another time when stress concentrators can be induced via handling, lowering in and backfilling and compacting.

Environmental

As with the above there are a number of fracture initiation mechanisms that can be classified as environmentally assisted. Two mechanisms that can be of concern to pipeliners are fatigue or corrosion fatigue and hydrogen induced cracking (HIC).

Large, and in some steels even small, pressure cycles can cause fatigue in pipeline steels due to plastic deformation causing micro- and macrocracking.

HIC requires both a source of atomic hydrogen and a mechanism to drive or permit the hydrogen atoms to enter the steel. Hydrogen atoms diffuse through the pipe wall and become entrapped at heterogeneous sites in the steel, leading to HIC at the mid-wall and hydrogen blisters on the pipe wall surface. The initiation of HIC blisters and associated cracks on the pipe wall surface are indications of the presence of hydrogen. The susceptibility of line pipe steels to HIC depends on several metallurgical and environmental factors. These factors must occur concurrently to cause a HIC flaw to initiate and to propagate to failure. Like SCC the result of this action is most often a catastrophic failure.[8]

For modern pipelines HIC is typically confined to the weldments and can be found via radiography or hydrostatic testing. The external source of hydrogen in these defects is generally from moisture in the welding rod flux when welding high strength (i.e. greater than Grade X-65 steels).

Higher carbon content steels can have localised hard or "cold" spots due to accelerated cooling. The potential for HIC in high carbon content pipelines can be driven by excess hydrogen available at the pipe wall via hydrogen evolution cause by CP current densities that are too high or other chemical reactions that produce hydrogen. Even at relatively low CP potentials HIC can be found in swampy or clayey areas because of sulphides acting a catalyst for hydrogen to diffuse into the steel microstructure. The emergence of alloy steels with low carbon contents and controlled rolling of the steel have reduced the potential for hard spots tremendously.

FRACTURE CONTROL

The desire of any pipeline designer is to ensure that when a defect reaches critical size and fails that the result is a leak, regardless of flaw geometry or type. In practice this is not accomplishable whilst still providing an economic pipeline design.

Fracture control is primarily accomplished via application of a two tiered design approach: 1) providing sufficient fracture initiation resistance, mainly via specifying sufficient toughness for the pipe specified and 2) ensuring sufficient fracture propagation resistance such that a running fracture is arrested as quickly as possible and generally within one pipe length or other length that can be readily repaired.

Fracture initiation is controlled by the fracture initiation toughness of the steel, the diameter, wall thickness, and grade of pipe, the size of the defect and stress acting on the defect. Fracture propagation[9] is controlled by the depressurisation of the medium being carried in the pipe, the operating temperature relative to the ductile-to-brittle transition temperature of the steel, the backfill conditions and fracture propagation toughness of the steel.

Specifying fracture initiation toughness and FITT are the means by which the pipeline engineer assures that the pipeline has sufficient resistance to fracture for flaw sizes that could be reasonably expected for the pipeline. The fracture initiation toughness are derived from the upper shelf CVN energy and the formulae presented in the following section.

The maximum critical flaw size for a known hoop stress level can be calculated for a pipe given the diameter, wall thickness and grade, regardless of the toughness of the steel. Models are available that calculate failure stress as a function of maximum flaw length for a given defect depth. The FITT is determined via destructive testing of samples at various temperatures until the temperature at failure does not influence the failure pressure but can be estimated at approximately 33° C (60° F) below the full scale 85% shear area transition temperature using either CVN or DWTT curves[10]. The DWTT 85% shear area transition temperature represents the FPTT by definition.

Consideration for mitigating fracture propagation include determining the FTPP via the CVN or DWTT 85% shear area transition temperature commensurate with the minimum operating temperature. Determining the toughness level required for crack arrest within a specified distance and evaluating whether the calculated toughness level is achievable. If it is achievable it is specified to the pipe supplier. If it is not, or is not commercially viable then consideration must be given to crack arrestors.

SUMMARY OF FORMULAE

Fracture Initiation

For a full wall defect, Maxey[11] has predicted that failure will occur when the following equation is satisfied:

$$\frac{K_c^2 \pi}{8c\bar{\sigma}^2} = \ln \sec \frac{\pi}{2}\left[\frac{M_T \sigma_T}{\bar{\sigma}}\right]$$

where:
σ_T = the hoop stress at failure
P = internal pressure level at failure

$\bar{\sigma}$ = the flow stress of the material (σ_{ys} + 68.95 MP)

M_T = the "Folias" correction i.e. $M_T \approx (1+1.255\frac{c^2}{Rt}-0.0135\frac{c^4}{R^2t^2})^{0.5}$

R = radius of pipe
t = wall thickness
$2c$ = the length of through wall flaw
$K_c^2 =$ a parameter related to material's resistance to fracture
where

$$\frac{12C_v}{A_c}=\frac{K_c^2}{E},$$

where
C_V = Charpy V-notch shelf energy
A_c = Fracture area of Charpy specimen
E = Young's modulus

There is a similar formula for part wall defects which can be found in the paper by Maxey referred to above.

Fracture Propagation

A number of authors have developed formulae that predict the required Charpy V-notch energy required for a propagating failure to be arrested within one pipe length in each direction from the initiating defect. These are summarised below:

PRC – Battelle: $C_{V2/3}=2.382\times10^{-5}\sigma_h^2\times(Rt)^{1/3}$

AISI: $C_{V2/3}=2.377\times10^{-4}\sigma_h^{3/2}(2R)^{1/2}$

British Gas: $C_{v2/3}=\sigma_h\left(\frac{2.08R}{t^{1/2}}-\frac{\nu R^{1.25}}{t^{3/4}}\right)\times10^{-3}$

Japan: $C_{v2/3}=2.498\times10^{-4}\sigma_h^{2.33}\times(2R)^{0.3}t^{0.47}$

CSM (Italsider) $C_{v2/3}=-0.627t-6.8\times10^{-8}\left(\frac{HR^2}{t}\right)+2.52\times10^{-4}R\sigma_h+1.254\times10^{-5}\left(\frac{Rt\sigma_h^2}{H}\right)$

Mannesmann: $C_{v2/3}=19.99\times10^{-8}e^{0.287\sigma_h^{1.76}(2R)^{1.09}t^{0.585}}$

where:
σ_h = hoop stress in MPa
R = radius of pipe in mm
t = pipe wall thickness in mm
ν = constant in British Gas formula and is 0.396 for natural gas
H = backfill depth in CSM formula in mm

When these formulae are applied to a buried pipe of 762 mm diameter, 12 mm wall thickness, X –65, buried to 750 mm, the required 2/3 Charpy value plotted against stress level is shown in the following graph. There are significant differences between the formulae and differing inconsistencies at various stress levels.

As a result of these differences, a designer must use his judgement as to the application of the most appropriate formula.

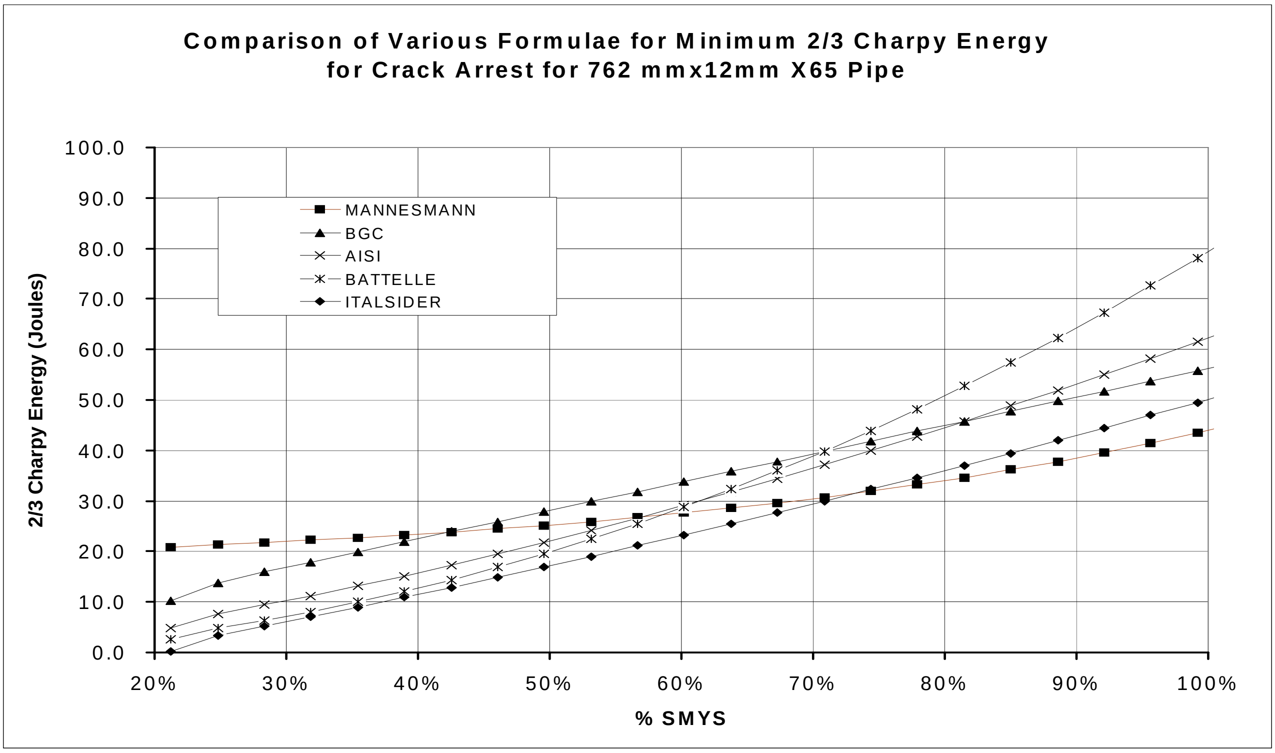

Figure 1 Comparison of various formulae for determining minimum toughness for crack arrest

Denting and Gouging as a Source of Ductile/Brittle Failure

Both Battelle[12] and British Gas[13] have recently carried out research on and developed formulae to assess the effect of denting and gouging on a pipeline. The research work determined that a gouge within a dent is more likely to initiate failure than a simple gouge or crack of the same geometry. This is a matter for concern, since third party damage to a pipeline often results in a gouge within a dent.

The empirical formulae to determine the stress level at which failure is likely to occur where the pipe has be gouged and dented is as follows:

$$\sigma = \frac{\bar{\sigma}}{90}\left(\frac{C_{v2/3}}{\frac{2cDd}{2Rt}} - 300\right)^{0.6}$$

where:

σ = the nominal hoop stress at failure (psi)
$\bar{\sigma}$ = the flow stress (yield + 10,000) (psi)
$C_{v2/3}$ = two-thirds size Charpy energy (ft-lbs)
D = maximum dent depth (inches)
R = pipe radius (inches)
$2c$ = gouge length (inches)
t = pipe wall thickness

Note: D has to be adjusted for internal pressure as follows:

$$D = \frac{D_p}{-0.22\ln\left(\frac{\sigma_p}{\overline{\sigma}}\right)}$$

where:

D	=	the maximum dent depth (in)
D_p	=	dent depth measured while pipe is under pressure (in)
σ_p	=	hoop stress when pipe in under pressure during measurement (psi)

Application of this formula to a typical pipe produces the following family of curves which represent the stress level at which failure is likely to occur under various conditions of gouge length and depth. As can be seen, relatively modest gouges reduce the containment strength of a pipeline considerably. However, one should always bear in mind that pressurised pipelines are remarkably resistant to denting.

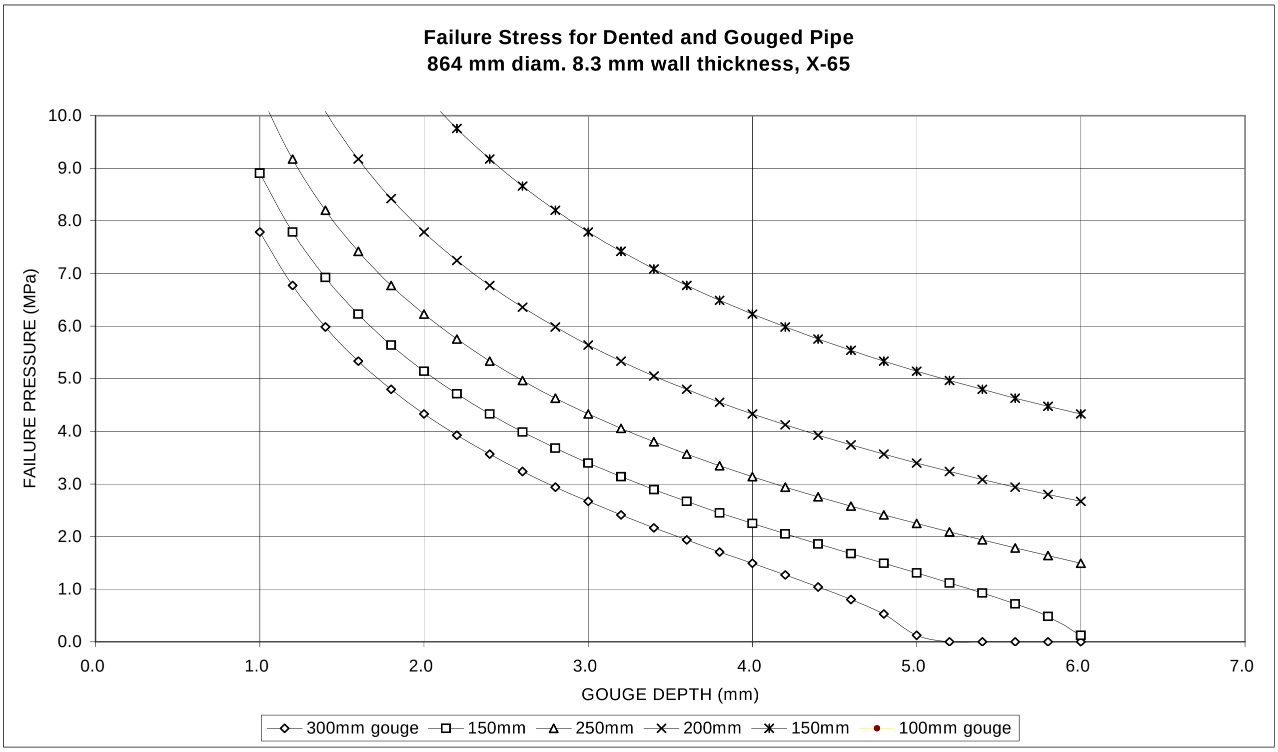

Figure 2 Failure pressure of dented and gouged pipelines, using British Gas formula

PIPELINE FAILURES IN AUSTRALIA

Even though the records are scanty, the authors are aware of eight significant natural gas pipeline failures in Australia, seven of which resulted in a propagating failure. None of these caused significant injury or loss of life, and each was repaired promptly.

The first recorded failure of a pipeline which resulted in a propagating crack occurred on 13 May 1978, when a bulldozer punctured the 356 mm diameter West Australian Natural Gas (WANG) pipeline. No fire resulted and the bulldozer driver suffered abrasions from dust and gravel ejected from the damage site. The Coroner's report describes the damage as follows:

"…an eight metre split had occurred along the top side of the pipeline; the split having emanated from an indentation made by the dozer blade. The split was in effect a tear initiated by the failure of the steel at the point of indentation to resist the internal pressure at the initiated point of weakness, and propagated into a rupture by the force of escaping gas."

No information is available to the authors concerning the fracture toughness of the steel, but one could conclude that because the pipeline was built in 1971, the specification of fracture toughness was not a significant issue. However, the toughness was clearly adequate to arrest a propagating failure.

The next propagating failure[14] occurred on a gathering pipeline in the Cooper Basin in January 1982, where a 323 mm pipeline failed due to stress corrosion cracking. The initiator was a crack, or nest of cracks, several of which had probably joined together to produce a critical defect size. The resulting failure propagated approximately 2 metres in each direction before arresting. In the following 18 months this pipeline failed twice more in a similar manner. The pipeline's owner replaced it after the third failure.

There is no record of the fracture toughness of this 323 mm diameter pipeline, but it can be inferred that it was relatively low.

In July 1982, the Moomba to Sydney natural gas pipeline failed due to stress corrosion cracking, which resulted in a propagating ductile fracture that extended for approximately 7 metres each way from the initiating crack before it arrested. The escaping gas caught fire. Subsequent analysis and inspection of the failed section of pipe showed that it had a yield strength of approximately 500 MPa and $C_{v2/3}$ of ≈75 Joules. These values implied a critical defect length of approximately 130 mm for a full wall thickness crack. It was estimated that the initiating crack was about 200 mm long. The difference is explained by the fact that the stress corrosion cracks had not penetrated the full wall.

By the use of the various formulae for ductile crack arrest, it was concluded that the fracture toughness of the steel was adequate. The table below sets out the results of application of the various versions of the crack arrest formulae:

Table 2 Minimum 2/3 Charpy values for fracture arrest in Moomba – Sydney Pipeline (864mm x 8.3 mm X-65 pipe)

Formula	Battelle	AISI	BGC	MANN	CSM	JAPAN
$C_{v2/3}$ (J)	47	47	55	33	40	44

In March 1983, another gathering line in the Cooper Basin failed due to stress corrosion cracking [15]. This time a 456 mm diameter ruptured twice within 2 weeks and in each case the fracture propagated for approximately 100 metres and the escaping gas caught fire. Subsequent analysis showed that the fracture toughness was very low - $C_{v2/3}$ of ≈11 Joules -and therefore well below that required to arrest a propagating fracture. Some observers have suggested that the failure mode was a brittle fracture, rather than ductile. The pipe was made from Australian steel which was of similar composition to sections of the Moomba Sydney pipeline, but without rare earth treatment. The designers of the pipeline did not take into account a requirement for appropriate fracture toughness and did not require the pipe manufacturer to meet any toughness criteria.

On 6 August 1984, the WANG natural gas pipeline was ruptured by impact from the ripper tyne of a bulldozer engaged in the installation of plastic conduit for an optical fibre. The pipe wall was penetrated and a large volume of gas escaped. After some 10 minutes, the escaping gas caught fire, having been ignited by the bulldozer's engine. The impact did not result in any propagating failure.

NORTH AMERICAN PIPELINE FAILURES

The following table compares the frequency rate for reportable incidents, fatalities and injuries are reported to the US DOT-OPS for 1995. The rate is expressed in an occurrence per mile of pipeline basis and reveals the following:

Table 3: Incident Frequency Summary US DOT-OPS data 1995[B]

	Gas Distribution 1,230,000 miles	Gas Transmission & Gathering 445,000 miles	Hazardous liquid 160,000 miles
Reportable incident	8,092 miles	5,366 miles	800 miles
Injury	15,000 miles	25,882 miles	6,957 miles
Fatality	76,875 miles	110,000 miles	66,666 miles

The following tables summarise the natural gas pipeline and hazardous liquids pipelines incidents by year for the period of 01/01/86 - 31/12/95.

Table 4: Natural Gas Pipeline Operators Incident Summary Statistics by Year 01/01/86 - 31/12/95

Year	No. of Incidents	Fatalities	Injuries
1986	83	6	20
1987	70	0	15
1988	89	2	11
1989	102	22	28
1990	89	0	17
1991	71	0	12
1992	74	3	15
1993	96	1	18
1994	80	0	19
1995	64	2	10
Totals	**818**	**36**	**165**
Averages	**82**	**4**	**17**

Table 5: Hazardous Liquid Pipeline Operators Incident Summary Statistics by Year 01/01/86 - 31/12/95

Year	No. of Incidents	Fatalities	Injuries

[B] Office of Pipeline Safety Data - 25/9/96. Historical totals may change as OPS receives supplemental information on incidents.

1986	209	4	32
1987	237	3	20
1988	193	2	19
1989	163	3	38
1990	180	3	7
1991	216	0	9
1992	212	5	38
1993	230	0	10
1994	244	1	57
1995	191	3	11
Totals	**2,404**	**29**	**276**
Averages	**200**	**2.4**	**23**

The cause of the incidents as reported by the operators using the same data base is contained in the following tables:

Table 6: Transmission and Gathering Pipeline Incident Summary by Cause for Calendar 1995

Cause	# Incidents	% of Total	Damage	% of Total	Deaths	Injuries
Internal Corrosion	5	7.81	$289,500	2.91	0	1
External Corrosion	4	6.25	$1,750,000	17.57	0	0
Outside Force	27	42.19	$4,435,250	44.54	0	2
Const./Material Defect	13	20.31	$2,498,000	25.09	0	2
Other	15	23.44	$985,000	9.89	2	5
TOTAL	**64**		**$9,957,750**		**2**	**10**

Table 7: Hazardous Liquid Pipeline Incident Summary by Cause for Calendar 1995

Cause	# Incidents	% of Total	Damage	% of Total	Deaths	Injuries
Internal Corrosion	13	6.81	$1,045,572	3.21	0	0
External Corrosion	23	12.04	$1,355,750	4.16	0	0
Defective Weld	9	4.71	$349,823	1.07	0	0
Incorrect Operation	26	13.61	$888,800	2.73	0	2
Defective Pipe	14	7.33	$3,773,100	11.58	0	2
Outside Force	54	28.27	$22,349,373	68.57	0	4
Malfunction of Equip	5	2.62	$513,005	1.57	0	0

Other	47	24.61	$2,318,266	7.11	3	3
TOTAL	**191**		**$32,593,689**		**3**	**11**

As with the Australian industry, records on pipeline failures are difficult to obtain. Data that can be obtained generally describes the incident, the investigation, determined failure mechanisms and remedial action, without any details on material properties (with the exception of diameter, wall thickness and grade) and how they attributed to the failure or conversely helped to control the fracture.

The tables above the show in detail that the United States, and this fact is true for all of North America, is not as fortunate as Australia in regards to the number of pipeline incidents that have occurred with over 3200 incidents reported on natural gas transmission and gathering systems and hazardous liquids pipelines over the ten year reporting period. Consistent with Australia, damage from outside forces causes the most incidents in the US.

Information on pipeline failures in Canada is readily available on the Internet from the Transportation Safety Board of Canada (TSB) website and can be easily downloaded. The authors have obtained information on two incidents; one attributed to external corrosion and the other to HIC because the detail of the TSB reports provide good background on the occurrence and attributable causes of these types of failures.

The DOT-OPS website also has information available on pipeline incidents, however, this information is not able to be directly downloaded. A request for the reports can be sent to the DOT who will send copies of incident reports to the requestor. We have included two incidents from the US in addition to those obtained from the TSB. The information on this incidents is not as complete as it has been obtained from other sources than the DOT-OPS Incident Reports.

On 23 July 1994 the TransCanada PipeLines Limited (TCPL) 914 millimetre (mm) outside diameter (NPS 36 inches) main natural gas pipeline, ruptured near Haileybury, Ontario, Canada.[16]

Damage to the pipeline consisted of 21.76m (approximately 71.4 feet) of ruptured pipe which had split open in the longitudinal direction and blown out of the pipeline system. The fracture created a crater approximately 16 m wide by 36 m long and roughly 2 to 4 m deep. The fire burned an area around the pipeline system of approximately 4.77 hectares.

The nominal wall thickness of the pipeline is 9.14mm (0.360 inches) with a SMYS of 448 megapascals (MPa), Grade X-65. This section of pipeline was constructed in 1972 and was externally coated at that time with a mastic primer, a hot applied asphalt enamel coating and an asbestos and kraft paper outerwrap. This section was hydrostatically tested in January 1973 to a minimum test pressure of 9,198 kilopascals (kPa). In 1986, the entire MLV section containing the accident site successfully passed a hydrostatic strength test. TCPL operated the at a MAOP of 6,454 kPa.

A metallurgical analysis of the fracture area determined that the pipe failed in shear-by-ductile overload mode as a result of extensive wall thinning from external corrosion. The defect that initiated the rupture was a patch of external surface corrosion which measured approximately 1,440 mm in length and 1,210 mm in width. There was no evidence of damage from the original construction. The area of the fracture initiation had experienced up to 70 per cent loss of material from the pipe wall.

Considering the amount of surface corrosion found at the fracture-initiation site and on the adjacent areas of pipe, coating degradation was a direct factor. The lack of mechanical strength of this type of coating, the normal operating oscillations of the pipeline, the rapid change in pipe gradient because of the steep slope of the right-of-way, and the high external stress due to the interaction of the pipe and the soil (rock and granular materials) were sufficient to continuously deteriorate the coating and to permit a corrosion cell to begin and progress to the point of rupture. A second direct contributor to the progression of the corrosion cell was the wet environment around the pipe.

This portion of Line 100-2 had never been inspected for corrosion using an in-line metal loss inspection device.

The occurrence site was situated in a high electrical resistance rock environment with measured values of soil resistivity in 1989 of approximately 1,250,000 ohm-centimetres at a 3 m depth.

Findings

1. The pipeline rupture initiated at a point on the surface of the pipe wall which had extensively thinned from external corrosion.
2. There were other areas of extensive thinning of the pipe wall due to external corrosion in the adjacent joints of pipe.
3. From the time of initial installation of this section of Line 100-2 in 1972 until 1976, little or no cathodic protection (CP) was provided by piggy-backing the CP system from a parallel pipeline within the R/W.
4. From 1990 until 1994, the proposed remedial repair plans for the CP system in this section of pipeline were delayed because of new pipeline construction activities, in spite of the fact that the level of CP was below the minimum industrial standard of 850 millivolts (mV).
5. From 1976 until the present, the rectifiers providing protection of this section of the pipeline were out of service for approximately 13 months.
6. When this section was installed in 1972, it was located in an area with high soil resistivity, with an underground stream acting as a continual source of oxygen, and in a rocky, steep-graded slope. These all acted to deteriorate the coating and initiate a corrosion cell.
7. Asphalt coatings have been found to deteriorate over time, leading to the need to provide greater protection, as evidenced by the increase in the number of rectifiers in this section to satisfy the increases in CP requirements to meet the minimum industrial standard of 850 mV.

On February 1994 TCPL's Compressor Station at Burstall, Saskatchewan[17], observed a large fireball in the distance to the southeast of their location.

Damage to the pipeline, which was part of Foothills Pipelines' "Eastern Leg", consisted of approximately 21.9 metres (m) (71.9 feet) of ruptured pipe which had split open in the longitudinal direction before being blown out of the pipeline a distance of approximately 125 m (410 feet).

The pipeline was constructed during the period 1981-1982 and was placed in service on 01 September 1982. The pipe was grade 483 megapascals (MPa) (grade X70) steel, had a double submerged arc, a 12 mm (0.427 inch) wall thickness and a 1,067 mm (NPS 42) outside diameter. The pipeline was coated with a double layer of polyethylene tape.

This section of the pipeline was covered with 1.5 m of soil which had a high sand content. The area had a high water table and had been an ancient seabed. Because of the high water table, the pipeline required saddle weights. The saddle weights were placed at 8 m (26.25 foot) intervals. The saddle weights, commonly referred to as “sulphurcrete”, were made up of a mixture of liquid molten sulphur, concrete aggregate and a bonding polymer. The coating on the sections adjacent to the rupture site showed good adherence to the pipe and the intact pipe was examined for quality of the remaining coating.

Hydrogen induced cracking (HIC) has been identified as the mechanism producing a mid-wall void in the pipe which, along with local hydrogen embrittlement, led to the rupture (TSB Engineering Report No. LP 25/94).

The factors attributed to the initiation and propagation of the HIC are as follows:

1. The external polyethylene coating must be damaged;
2. Atomic hydrogen must be produced at the pipe surface from the CP system and/or from bacterial activity;
3. Atomic hydrogen must be continuously diffusing into the steel due to the presence of a surface “poison”;
4. The microstructure of the steel must be susceptible to hydrogen entrapment, namely the steel must have heterogeneous features in the microstructure, such as type II elongated manganese sulphide inclusions and bands of carbon rich material;
5. Molecular hydrogen gas must be forming and accumulating along the heterogeneous features; and
6. In order for rupture to occur, the mid-wall crack must propagate to the inner or outer surface of the pipe and the length of this surface breaking flaw must be greater than the critical flaw size at the operating pressure and toughness of the pipeline.

Only in very rare situations has HIC affected the pipe wall structure in sweet natural gas (i.e., natural gas free of hydrogen sulphide gas) as in this case.

This location was found to contain chloride ions which can accelerate the production of hydrogen and the growth of HIC.

Findings

1. The pipeline rupture initiated at the mid-wall of the pipe steel under or adjacent to a saddle weight.
2. Hydrogen induced cracking (HIC) has been identified as the mechanism that produced this mid-wall void.
3. The polyethylene tape coating disbonded from the pipe and was perforated as a result of pipe movement, circumstances which permitted free hydrogen to come into contact with the pipe surface.
4. Hydrogen was produced at the pipe surface from either the cathodic protection system and/or from anaerobic bacterial activities.

5. The diffusion of hydrogen into the steel surface was continuous, and various “poisons”, possibly induced by the sulphurcrete saddle weights, accelerated the reaction and growth of HIC.
6. The microstructure of the steel contained type II elongated manganese sulphide inclusions and bands of carbon rich material, which made the microstructure of the steel susceptible to hydrogen entrapment.
7. The chemical analysis of the pipe steel indicated that there had been insufficient calcium added to the steel melt before pipe fabrication to spheroidize the manganese sulphide inclusions.

In March 1994 in Edison, New Jersey, a 36-inch diameter (900mm DN) gas transmission pipeline operated by Texas Eastern Transmission Corporation ruptured. The resulting fire destroyed and/or damaged eight three story apartment buildings. The incident caused the evacuation of 1500 people and injuries to more than 100. At the time of the failure the pipeline was operating at 970 psig (6,690 kPa).

There was a lot of debris, including barrels, concrete blocks, a part from the adjacent asphalt plant, tires and bits and pieces of car frames buried around the pipeline in the asphalt plant yard. An alignment sheet apparently had erroneously indicated that pipeline exited the asphalt plant property before the area where the trash was buried. The pipeline had numerous marks from construction equipment around it outside diameter in the vicinity of the rupture.

The actual failure was caused by a dent-and-gouge defect which the critical flaw length of the defect was reached during operation some time after the defect had been introduced to the pipeline. It is thought that the defect was caused by the teeth of a backhoe.

CONCLUSIONS TO BE DRAWN FROM THE PIPELINE FAILURES

Firstly, one must take into account the fact that five of the failures occurred on gathering pipelines in a remote area due to stress corrosion cracking. In its analysis of the first failure, the owner of those pipelines did not take into account the fact that significant lengths of its gathering system suffered from severe stress corrosion cracking and hence carried out only localised repairs. Stress corrosion cracking was a little known phenomenon in Australia in the early 1980s and the failure of these gathering lines, together with the failure of the Moomba to Sydney pipeline were the first indications of the effect. Given the current state of knowledge on stress corrosion cracking and the high level of toughness which has been required of pipeline steels since the mid-1970s, the likelihood of a repeat of such a spate of pipeline failures, which result in propagating cracks, is very low. However, pipeline designers and operators must maintain a high level of vigilance to prevent these types of initiating events – SCC and third party interference – and ensure that steel toughness is more than adequate to arrest propagating failures. If toughness alone does not give the designer sufficient confidence in the arrest of cracks, other measures, such as crack arresters must be installed.

Owners and operators of pipelines which were built in the 1960s and 1970s and which are coated with coal tar enamel, tape or other coatings which show a propensity for disbondment and which, when disbonded, shield the pipe’s surface from cathodic protection currents, should have in place investigative programs to check for the presence of stress corrosion cracking. There are number of programs which have been developed by operators and industry associations. The Pipeline Authority had one such program in place after its 1982 failure, as did Santos after the failure of the gathering lines in the

Cooper Basin.[18] TransCanada PipeLines has also developed a similar and quite sophisticated analysis program to determine sections of pipeline which might be more likely to be affected by stress corrosion cracking. Another program was developed by the Pipeline Research Committee – Methods Prioritizing Pipe Maintenance and Rehabilitation[19] (PIMAR) PR-3-919 L51630 – has been used as a basis for the assessment of sections of pipeline where stress corrosion cracking may be present. El Paso Natural Gas Company, in association with TransCanada PipeLines and the PRC, has developed a technique named SCCRAM (Stress Corrosion Cracking Risk Assessment Matrix)[20]. All these programs use similar indicators, including:

- Presence of persistent moisture in the vicinity of the pipeline
- Low soil resistivity
- Poor, disbonded coating
- Coating acting as shield for cathodic protection
- High operating temperatures
- Stress levels in excess of the threshold stress for SCC
- Cyclic stress
- Very high or very low cathodic protection voltages
- Pre-1970s steel technology

Many companies have been most successful in applying these programs for finding stress corrosion cracking prior to pipeline failure.

SUMMARY

It is essential that readers, pipeline owners and regulators keep in perspective the pipeline failures reported in this paper. The failures which occurred in Australia prompted a close review of pipeline design and operating standards, which were reflected in the subsequent issue of the Australian Pipeline Standard, AS2885-1987. Pipeline designers, operators, and regulators who took an active role in the re-writing of the Standard were very conscious of the need to ensure that public safety and continuity of supply were maintained by requiring pipeline designers and operators to take into account the causes and effects of the failures which had occurred in Australia. Advice was sought throughout the world on methods of safeguarding pipelines against pipeline rupture and at least two pipeline owners gained membership of the American Gas Association's Pipeline Research Committee to be able to tap into the latest research on pipelines in North America, the United Kingdom and Europe, with specific emphases on stress corrosion cracking, weld defect assessment and fracture control. This information was brought before the Standards committee and incorporated in the new Standard, in an Australian context.

The steel and pipe manufacturing industry also made very significant contributions to the development of the Standard and responded to the industry's resulting requirements by making high quality, tough pipe.

The examples listed in this paper clearly demonstrate that no pipeline designer or operator should overlook the need for very careful design for fracture control. However, the response by the industry to problems it has encountered has resulted in an assurance to the public and regulatory authorities that both the design and operation of new and older petroleum pipelines in Australia are of a very high standard. Potential problems can be engineered out and all risks mitigated to extremely low levels.

This approach has been continued in the latest issue of the Australian Standard where more emphasis has been given to engineering out risk and particular attention has been paid to fracture control in pipelines. As a result, Australia will continue to have very safe and reliable petroleum pipelines.

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