Risk has been intuitively understood since the dawn of human history. Indeed, the ability to deal sensibly with risk has underpinned the rise of civilization. It is a fair assumption that primitive man perceived the dangers associated with hunting wild animals or using fire; but he evidently also judged the benefits to be worthwhile.

When modern businesses deal with risk, the object of balancing benefits against possible drawbacks remains the same, but intuition is no longer a dependable means of assessment. A more formalized approach is needed. The classic example is the insurance industry which gauges risk as the product of the amount of money it would have to pay out as a consequence of the insured event occurring, multiplied by the probability of that event occurring. In other words:

\[
\text{risk} = \text{consequence} \times \text{probability} \quad [1]
\]

For the insurer the process is quite precise. The consequence is usually set by the level of cover specified in the policy, and the probability is obtained from the relevant statistical publications: mortality tables for life assurance, local crime rates for house contents insurance etc. Once the risk is estimated, it is then managed by the simple expedient of levying an adequate premium.

The pipeline operator will also define risk using equation [1]. However, managing risk in the pipeline industry does not involve the precision of, say, life assurance. There is fuzziness surrounding both the nature and extent of the consequences, and the probability of failure incidents that will give rise to such consequences. Moreover, the pipeline operator does not enjoy the luxury of being able to adjust premium income to cover risk. Rather, he must make judgements as to whether or not the risk is acceptable. If it is not, then he must allocate resources either to reduce the probability of failure, to limit the consequences of a failure, or both.
When we think of risk in the context of pipelines, our first thoughts are conditioned by the fact that pipeline failures can cause harm to personnel. In the USA for example:

- 86 people (35 employees and 51 members of the public) were killed as a result of incidents involving natural gas pipelines between 1970 and 1984 (1). 36 were killed in a total of 818 incidents from 1985 to 1995 (4)

and

- 19 people were killed as a result of incidents involving LPG pipelines between 1976 and 1985 (1), although there were no reported fatalities in 1995 resulting from these lines (4).

Elsewhere in the world the death-toll has been greater. A poignant example was in Guadalajara (Mexico) in 1992 when gasoline leaked from a 12" underground pipe. The resulting explosion and fire led to the death of nearly 200 local inhabitants. Over 1300 were injured (28). There have also been some very fortunate near-misses. In 1982 in New South Wales the Moomba to Sydney natural gas pipeline ruptured 4.2 km from the Moomba plant. A crack some 13m long was produced. The gas ignited and the resulting fire did some damage to the surrounding uninhabited bush. It was fortunate that this failure did not occur further along the line in the Sydney area.

In the light of the societal risks it is little surprise that safety is the prime concern of the regulatory bodies that police pipeline operations. In the case of a line carrying a toxic or flammable fluid it is the norm for a risk assessment to be conducted prior to licensing a new line or permitting a change of use of an existing line. Typically, such an analysis will consider:

- the probability that a pipeline failure will take place

and

- the number of casualties such a failure might lead to at any given location along the route.

The probability of failure can be estimated from historical records. In Europe CONCAWE recorded 93 incidents on 86400 km oil and gas pipelines in the period 1972-1976. This is a failure rate of $2.2 \times 10^{-7}$ per m year. More recent European data have been assessed by Blything (2) and are given in Table 1. These show a trend towards lower failure rates for
more valuable, have received more intensive protection and inspection.

TABLE 1

PIPEDLINE FAILURE FREQUENCIES (Blything (2))

<table>
<thead>
<tr>
<th>Pipeline OD</th>
<th>No. of Failures (1975 - 1980)</th>
<th>Failure Rate x 10^7 per m year</th>
</tr>
</thead>
<tbody>
<tr>
<td>6 - 10&quot;</td>
<td>35</td>
<td>12.0</td>
</tr>
<tr>
<td>12 - 14&quot;</td>
<td>12</td>
<td>7.7</td>
</tr>
<tr>
<td>16 - 18&quot;</td>
<td>10</td>
<td>5.3</td>
</tr>
<tr>
<td>20 - 22&quot;</td>
<td>6</td>
<td>4.2</td>
</tr>
<tr>
<td>24 - 30&quot;</td>
<td>3</td>
<td>2.1</td>
</tr>
<tr>
<td>&gt;32&quot;</td>
<td>4</td>
<td>2.4</td>
</tr>
</tbody>
</table>

The data of Jones and Gye (3) (Figure 1), which differentiate between ruptures and more common, but less dramatic, leaks also shows correlation between reduced failure rates (by rupture) and pipe size; although the leak rate is not apparently sensitive to pipe size.

Fig 1 - Pipeline Failure Frequencies after Jones & Gye
happen if a leak occurred (for example leading to a gas cloud ignition)? This in turn defines
the risk to individuals at various distances from the line (3). The regulatory authorities will
require that the risk is as low as reasonably practical. According to Movley (5), this is a
concept in UK law which means that if a precaution is practicable it must be taken unless in
the circumstances it would be unreasonable. To consider whether it is reasonable requires a
computation to be made in which the degree of risk is weighted against the cost in money,
time or trouble of the measures necessary to avert the risk.

As a rule of thumb, the risk to an individual from the presence of the pipeline should be no
higher than the risk from natural disasters generally.

The outcome of such a risk analysis may involve any, or all, of the following:

- re-routing of the line away from populated areas
- a requirement for thicker walled pipe (at least in some locations). For example,
  lowering the design factor\(^1\) from 0.72 to 0.3 can virtually eliminate the risk of a
  rupture-before-leak incident (6)
- a requirement for a regime of periodic inspections, possibly including intelligent pig
  surveys.

Although the risk of casualties is predominant in the context of hydrocarbon gas pipeline
failures, it is not the only concern of the pipeline operator. Table 2 lists the more common
possible consequences. It may be noted that failure in this context is viewed not only in the
conventional sense as a loss of containment, but also as arrival at a condition which
necessitates intervention to prevent, or forestall, a leak.

For oil lines, the casualty rates are circumscribed by its non-explosive nature compared to
natural gas, ethylene, gasoline etc.; but the pollution clean-up costs can be substantial. In
1989, for example, a 12" line failed at Bromborough (UK) and 160 tonnes of crude leaked
into the River Mersey. The owners, incurred £1.4 million in clean up costs and were
prosecuted by the, then newly formed, National Rivers Authority\(^2\) under the UK's 1974
Control of Pollution Act. They were fined an additional £1 million (7).

---

1 This is the ratio of the operating stress to the yield stress of the pipeline material.
2 now the Environment Agency
### SOME CONSEQUENCES OF PIPELINE FAILURE

**Failure = leak/rupture**
- toxic hazards
- fire/explosion
- casualties
- 3rd party damage
- loss of product inventory
- loss of production
- loss/repair of line
- pollution clean-up costs
- increased insurance premiums
- loss of public confidence
- increased scrutiny by statutory bodies
- litigation

**Failure = leak/rupture judged to be imminent**
- reduced pressure/throughput
- increased inspection
- increased monitoring
- repairs
- premature replacement

By contrast, the water industry's attitude to pipeline failures is different. Since its fluid is neither dangerous nor polluting, it adopts a more pragmatic attitude. The concern is to control, but not eliminate, the aggregate loss of throughput and to limit the instances of disruptive bursts in strategic mains.

### The Role of Corrosion

From the foregoing analysis of pipeline risk assessment we might argue that corrosion is unimportant. What is of importance is the statistical likelihood of a failure and the consequences it will generate. In this analysis the cause of the failure is immaterial.

However, such an argument hides the intuitively obvious point that a pipeline that is well engineered and well managed will be less prone to failure than one that is not. In this respect, it is worth noting the 1982 paper by Turner (8) which summarizes the causes of failure in cross-country pipelines (see Table 3). This shows that, in the UK, the rate of corrosion induced pipeline failures is broadly similar to that caused by external interference such as accidental mechanical impacts. The corresponding figures for process plant piping leakage (9) and for submarine gas pipelines (10) also show the significant influence of corrosion (see Tables 4 and 5). More recently it has been disclosed that 50% of all pipeline failures in the North Sea are due to corrosion (26). The corresponding figure for US hazardous liquid pipelines is 19% for 1995 (27), although it should be noted that this figure relates only to leakage incidents. It does not include corrosion problems that were remedied prior to leakage.
CAUSES OF PIPELINE FAILURE (after Turner (8))

<table>
<thead>
<tr>
<th></th>
<th>% of all Failures</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>US</td>
</tr>
<tr>
<td>Corrosion</td>
<td>45</td>
</tr>
<tr>
<td>External Interference</td>
<td>28</td>
</tr>
<tr>
<td>Defect</td>
<td>12</td>
</tr>
<tr>
<td>Incorrect Operation</td>
<td>2</td>
</tr>
<tr>
<td>Other</td>
<td>13</td>
</tr>
</tbody>
</table>

TABLE 4
FAILURE MODES FOR SUBMARINE GAS PIPELINES (9)

<table>
<thead>
<tr>
<th>Failure Mode</th>
<th>% Occurrence</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mechanical defect</td>
<td>14.0</td>
</tr>
<tr>
<td>Construction defect</td>
<td>15.4</td>
</tr>
<tr>
<td>Corrosion</td>
<td>21.2</td>
</tr>
<tr>
<td>Impact</td>
<td>27.6</td>
</tr>
<tr>
<td>Natural hazard</td>
<td>9.6</td>
</tr>
<tr>
<td>Others</td>
<td>12.2</td>
</tr>
</tbody>
</table>

TABLE 5
MAIN CAUSES OF PIPING LEAKAGE FROM PROCESS PLANT (10)

<table>
<thead>
<tr>
<th>Failure Mode</th>
<th>% Occurrence</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manufacturing/Fabrication defects</td>
<td>9.6</td>
</tr>
<tr>
<td>Welding*</td>
<td>11.8</td>
</tr>
<tr>
<td>Materials selection*</td>
<td>28.8</td>
</tr>
<tr>
<td>Fatigue*</td>
<td>12.1</td>
</tr>
<tr>
<td>Corrosion/erosion</td>
<td>24.6</td>
</tr>
<tr>
<td>Others</td>
<td>13.1</td>
</tr>
</tbody>
</table>

* these failure modes are often exacerbated by corrosion
non-corrosion failures across a broad spectrum of industrial activities. For example, the Dupont Company reported (11) that, of 685 failures in its chemical plants observed between 1968 and 1971, 55% were due to corrosion and 45% to mechanical failure. This experience is mirrored in the petroleum production industry, where Britoil (12) found that 33% of its equipment failures between 1978 and 1988 were a result of corrosion damage. Recently, one of the world's major producers has recognized that 5% of its world-wide production is lost due to corrosion and, moreover, 40% of its accidental hydrocarbon releases to the environment are corrosion related.

Manifestly, therefore, corrosion risks constitute an important subset of the overall risk encountered by pipelines. The point is emphasized by the fact that the failures noted above at Guadalajara, New South Wales and Bromborough were all caused by corrosion or, perversely, by corrosion protection. The significance of corrosion is further emphasized by Jelinek (13) who has noted seven offshore pipeline failures, each of which was caused by corrosion. Although each failure might be considered comparatively minor (no casualties, little or no pollution and no newspaper headlines), the average repair cost for each was over $1.6 million (1986 prices).

The Identification of Corrosion Risk

Corrosion is regarded by most as a slow but progressive process that emerges as a problem later rather than sooner in the lifetime of a pipeline. This is broadly true and is exemplified by the logarithmic nature of cumulative leaks versus time data for ageing, unprotected lines. However, it needs to be recognized that corrosion takes many forms. As a rule, the more localized it is, the more rapid the rate of pipe wall penetration.

For example, the general corrosion rate of steel exposed to aerated soils or non-polluted natural waters lies in the range 0.01 to 0.1 mm year. In such bland environments it is probable that decades will pass before the failure even of an unprotected line. Pitting corrosion, which in carbon steel lines may have causes as varied as:

- microbially influenced corrosion (MIC) - external or internal
- long line effects - external
- stray current electrolysis - external (usually)
- wet CO₂ in hydrocarbon lines - internal
- welding problems - internal
once pitting initiates, then reduces from decades to years or, in extreme cases, even to months.

Further, there are some corrosion processes that can give rise to cracking modes of failure:

- carbonate/bicarbonate stress corrosion cracking - *external*
- sulphide stress corrosion cracking (sour gas) - *internal*
- hydrogen embrittlement\(^5\) - *external (usually)*
- corrosion fatigue - *internal or external*

This is characterized by an indeterminate crack initiation period, ranging from seconds to centuries. During this time, incipient cracks are undetectable. The initiation period is then followed by crack growth at a rate that may lie in the range \(10^{-6}\) mm/s to \(10^{-2}\) mm/s. Times to failure will, therefore, vary greatly. For example, there has been no reported incidence of carbonate/bicarbonate cracking in a pipeline less than 5 years old (14). On the other hand, in 1971, a crude petroleum pipeline failed by sulphide stress corrosion cracking within a matter of hours of being put into sour service (15). There have also been at least two cases of duplex stainless steel offshore pipeline components, one a flowline and the other a flowline hub, failing under hydrotreat prior even to entering service. In one case the problem was judged to be caused by the combination of an improper metallurgical condition and applied cathodic protection (CP) which resulted in hydrogen embrittlement. The other was judged to have been caused by contaminated hydrotreat fluid.

The problems are not restricted to the line pipe itself. Other pipeline features must also be considered. For example, in 1996 there were costly failures of valve stems in a strategic high pressure gas line in the Arabian Gulf area. The items in question were fabricated in a precipitation hardened stainless steel which had not received the appropriate tempering heat treatment. The first of the stems sheared as a result of sulphide stress corrosion cracking within a few months of entering service.

It will be appreciated that, perversely, the more localized is the corrosion, the less likely it is to be detected in any routine inspection plan. There are some schools of thought (6) that pitting penetration is a less dangerous mode of failure than general wall thinning because it leads to a leak rather than a burst.

\(^5\) Sometimes referred to (improperly) as hydrogen assisted stress corrosion cracking.
Guadalajara incident, for example, involved pitting corrosion of a gasoline line, induced by the stray current electrolysis failure of an adjacent water line (16). Although the rate of gasoline leakage was low, it went undetected for a long time allowing fumes to permeate the residential sewer network before the inevitable ignition. Through-wall cracks on the other hand, are by their nature likely to lead to ruptures. The above-mentioned gas line failure in New South Wales was a result of such a crack caused by carbonate/bicarbonate stress corrosion cracking (17).

Although corrosion might be insidious it is not unmanageable. There is rarely a new event in corrosion. Table 6 lists the forms of corrosion known to afflict buried or submarine carbon steel pipelines. Given the extensive number of years of experience with buried and submerged lines, it is an extremely remote possibility that a hitherto unobserved form of corrosion will manifest itself in the future.

**TABLE 6**

**STEEL PIPELINES - CORROSION MODES**

<table>
<thead>
<tr>
<th>External</th>
<th>Internal</th>
</tr>
</thead>
<tbody>
<tr>
<td>general, in</td>
<td>general, in</td>
</tr>
<tr>
<td>♦ soil</td>
<td>♦ product</td>
</tr>
<tr>
<td>♦ MIC</td>
<td>♦ hydrotest</td>
</tr>
<tr>
<td>♦ stray current</td>
<td>♦ mothballing</td>
</tr>
<tr>
<td>♦ macrocells</td>
<td></td>
</tr>
<tr>
<td>♦ corrosion cracking</td>
<td>♦ MIC</td>
</tr>
<tr>
<td>♦ carbonate/bicarbonate</td>
<td>♦ erosion/corrosion</td>
</tr>
<tr>
<td>♦ hydrogen embrittlement</td>
<td>♦ deposit</td>
</tr>
<tr>
<td>♦ hydrogen pressure induced cracking</td>
<td>♦ weld attack</td>
</tr>
<tr>
<td>♦ corrosion cracking</td>
<td>♦ corrosion cracking</td>
</tr>
<tr>
<td>♦ sulphide SCC</td>
<td></td>
</tr>
</tbody>
</table>

Thus, experience tells us that, given knowledge of the pipeline material and of the internal and external environments together with the circumstances of exposure to those environments, the corrosion engineer can confidently predict those forms of corrosion that are possible and those which are not. Moreover, for the near uniform forms of corrosion, deterministic information
These allow us to make worst-case predictions of the rates of attack or time to failure. For localized corrosion morphologies, it is more usual to use a probabilistic approach (21).

Where the predicted times to failure are very much greater than the design life of the line, then there is no need to make a corrosion management intervention. When this is not the case, the well-established corrosion mitigation measures listed in Table 7 are available for use separately, or in combination, as required.

TABLE 7
CORROSION MANAGEMENT OPTIONS FOR PIPELINES

<table>
<thead>
<tr>
<th>External</th>
<th>Internal</th>
</tr>
</thead>
<tbody>
<tr>
<td>coating</td>
<td>dehydration</td>
</tr>
<tr>
<td>cathodic protection</td>
<td>gas sweetening</td>
</tr>
<tr>
<td>corrosion allowance (rare)</td>
<td>corrosion allowance (usual)</td>
</tr>
<tr>
<td></td>
<td>inhibitors and biocides</td>
</tr>
<tr>
<td></td>
<td>process control</td>
</tr>
<tr>
<td></td>
<td>lining/cladding</td>
</tr>
<tr>
<td></td>
<td>material selection</td>
</tr>
<tr>
<td></td>
<td>cathodic protection (rare)</td>
</tr>
</tbody>
</table>

To aid in the selection of the most appropriate corrosion management options it is helpful to conduct a corrosion risk assessment. There are a number of approaches to this (for example, see references 22 & 23). Essentially the exercise combines objective predictions of failure probability (or residual life (22)), with more subjective assessments of the consequences of corrosion.

The process is applied separately to discrete pipeline components. Thus, for the purpose of corrosion risk assessment, the pipeline or pipeline network might be divided into zones based on product temperature and internal pressure range, and on the external environment (e.g. subsea, shore approach, onshore (rural) etc.). The various pipeline appurtenances also need to be considered (e.g. valves, pig launchers, risers, tees, expansion loops etc.)

The outcome of the analysis may be a numerical reflection of risk (22) generated by quantifying the probability and consequences factors, and then combining them in a risk
tend to cluster into groups which can be translated into "high", "medium" or "low" risk categories. Other methodologies consider separately the perceived severity of the probability of corrosion failure and its consequences. This gives rise to risk zones of the type shown in Table 8.

**TABLE 8**

**ZONES OF RISK CATEGORY**

<table>
<thead>
<tr>
<th>Zone 1</th>
<th>Zone 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Consequence</td>
<td>High Consequence</td>
</tr>
<tr>
<td>High Probability</td>
<td>Low Probability</td>
</tr>
<tr>
<td>Zone 2</td>
<td>Zone 4</td>
</tr>
<tr>
<td>Low Consequence</td>
<td>Low Consequence</td>
</tr>
<tr>
<td>High Probability</td>
<td>Low Probability</td>
</tr>
</tbody>
</table>

**Risk Modification**

Intelligent corrosion management aims to move towards Zone 4 in Table 8 (i.e. low consequence and low probability). In the case of a high pressure gas line, for example, this may mean erring towards Zone 2 rather than Zone 3. Translated into corrosion engineering terms, this might mean striving to eliminate the risk of transverse cracking modes of failure (e.g. sulphide stress corrosion cracking) whilst allowing the risk of pitting in preference to general thinning; the object being to ensure that any failure will be a leak rather than a rupture. In a particular instance, for example, it might be viewed as important to moderate the use of CP, thereby reducing the risk of embrittling weld areas on high strength lines, even though this might permit some local underprotection and external pitting in some locations (i.e. operation in Zone 2). The converse approach, which would involve over enthusiastic cathodic polarization, would reduce the probability of a failure by corrosion pitting, but might shift the operation into Zone 3 by introducing a low probability of embrittlement associated with its unacceptable consequences.

The generic selection of corrosion control options, in so far as ensuring pipeline integrity, rarely presents a problem for a corrosion engineer. More often than not, it calls for little more
impressed current CP systems or to adjudicate on corrosion inhibitor dosage, a regime of monitoring may be introduced, together with any statutory surveillance and inspection.

It should be stressed that risk management does not always focus on lowering the corrosion risk. Occasionally, an increase in the corrosion risk is justified in the context of the overall enterprise. An example of this involved a Southern North Sea production platform producing gas from three reservoirs, one of which contained H₂S.

In the early 1990's a de-manning exercise led to substantial modifications to the field facilities. This included removal of the relatively labour intensive dehydration facilities on the platform. The result was that wet, and therefore potentially corrosive, gas was now to be exported through the pipeline. Moreover, the level of H₂S in one of the reservoirs meant that, when the exported product contained a substantial proportion of that feed, the wet pipeline would, for the first time, encounter sour service as defined by the industry codes of the time.

Global Corrosion conducted a review of the situation, including an audit of the various materials and welding codes that had been applicable at the time the pipeline was constructed some twenty five years earlier. The outcome was a conclusion that the line did not meet the current requirements for sour service in that it could not be guaranteed that material hardness at welds were below the Rc22 hardness limit set by NACE in MR-0175.

Having been identified, the risk was managed by enforcing a discipline of blending production from the three reservoirs to ensure that the H₂S in the combined fluid was diluted to below the threshold level for classification as sour. As part of that discipline, H₂S monitoring was installed to provide an alarm if the H₂S level rose above that threshold.

The Cost of Zero Failure

Thus far we have considered risk solely in the context of failures. If a line is designed for a given period of service, and it achieves that life with little or no evidence of corrosion, then no-one is accused of failure. However, what is rarely questioned is whether that absence of corrosion failure has been achieved at a reasonable cost. It is, after all, a questionable wager to spend more on averting a corrosion failure than it would cost to remedy its consequence. Table 9 lists some of the sources of potential overspending on corrosion management.
PIPELINE CORROSION MANAGEMENT
POTENTIAL OVERSPENDING

<table>
<thead>
<tr>
<th>Capital</th>
<th>Operational</th>
</tr>
</thead>
<tbody>
<tr>
<td>• unnecessarily expensive material</td>
<td>• excessive inhibitor consumption</td>
</tr>
<tr>
<td>• excessive wall thickness</td>
<td>• over operation of CP system</td>
</tr>
<tr>
<td>• over-specified coating</td>
<td>• too frequent CP/coating surveys</td>
</tr>
<tr>
<td>• over-designed CP system</td>
<td>• too frequent internal inspection</td>
</tr>
<tr>
<td>• excessive monitoring provision</td>
<td>• excessive monitoring</td>
</tr>
</tbody>
</table>

Some examples of such over enthusiastic action that Global Corrosion has encountered include:

**Excessive corrosion allowance**

The case in point was an offshore crude oil pipeline laid in the Norwegian sector of the North Sea (mid 1980's). Quite properly, a corrosion allowance had been added to the pipe wall thickness to accommodate the corrosive effect of any water drop out. However, it was also necessary to increase the wall thickness of the line, above that needed for pressure retention duty, to allow for the stresses involved in pipe-laying. In the event, both the corrosion and pipe lay allowance were added separately to the design wall thickness. This was despite the obvious fact that the pipe-laying allowance was only required at the start of life, whilst the need for the corrosion allowance would develop whilst the line was in service. A considerable saving, by way of pipe material and offshore welding costs, could have been obtained if the two allowances had been combined.

For example, work carried out at that time on another subsea pipeline project (27) demonstrated that combining the additional wall thickness needed to resist buckling to the corrosion allowance for a 28" line necessitated a 13.6% increase in pipe weight, and a similar percentage increase in the as-laid cost.

**Excessive CP - sacrificial anodes - offshore**

There is a general consensus that the current offshore CP design guidelines (e.g. 23) are conservative in that they embody pessimistic predictions of:
The current densities needed for protection
• the output capacities of modern sacrificial anodes
• the performance of modern pipeline coatings

The resultant designs inevitably incorporate excessive sacrificial anode burdens. This said, it must be appreciated that the cost of the anodes is only a very small part of the as-laid cost of an offshore line. Some over-design is, therefore, acceptable, or even desirable, if the end result is the prospect of life extension of the line.

However, the anode weight calculation for one particular North Sea pipeline in the early 1980's took conservatism to extremes. It would appear that, having calculated the required weight of anodes as a number of pounds, the anodes were inexplicably ordered as that same number but this time of kilograms, generating an additional safety factor of 2.2!

Excess CP - impressed current - onshore

The current required to protect a buried pipeline increases gradually throughout its life as the protective coating, which may be thought of as the primary corrosion defence, breaks-down.

It is current practice among CP designers these days to determine the size of a CP installation for a new pipeline on the basis of the predicted current demand at the end-of-life, which will reflect the maximum assumed coating breakdown. The result is that the full capital cost of the CP installation is incurred at the start of life and, for the most part, the equipment is operated inefficiently at the bottom end of its output range. A further problem is that there is a universal tendency to react to some slight lowering of protection levels at a location remote from the CP station by increasing the output of the CP supply. In many cases this can lead to excessive polarization near the drain point which in turn causes cathodic disbondment of the coating and an unbalancing of the protection levels along the line. The potential levels at the remote location will again tend to drift out of specification, prompting another rise in the CP system output and a continuation of the unbalancing of the system.

In many cases there would be a discounted cash flow benefit to installing lower rated CP systems at the start of life and then, if required, adding further discrete systems in later life at locations where CP surveys showed there to be a need. Such an approach would also benefit current distribution along the line.
Other papers at this meeting will address the role of data gathering inspection pigs in managing the risk of pipeline failures. The topic will not be discussed here. Suffice it to say that running an inspection pig is an expensive activity and their use should be focused on those lines where a proper risk assessment shows them to be merited. In passing, it is worth noting that, although the technology of intelligent pigging is impressive, it is not infallible. For example, PDO (24), reporting on a gas pipeline rupture that occurred on a recently inspected line in 1994, have highlighted the limitations of the technique in respect of detected internal grooving type corrosion.

Aside from the risk that inspection will give a false indication, there is the possibility that the inspection activity itself will affect the corrosion management of the line. An unusual example of this occurred recently in the Middle East.

Short lengths (~1 km) of 24", 30" and 36" gas transfer lines had been buried in dry sand in 1981. No anticorrosive coating was applied to the lines, but they were provided with thermal insulation comprising polyurethane foam blocks covered by spiral wrapped bitumen backed tape.

In 1990 the lines were inspected by means of selected excavations. Due to the dry nature of the sand the procedure used was to empty a bowser of produced brine on the ground at the location of interest, and then manually to excavate the wet sand. This done, sections of the tape and polyurethane were cut away to reveal pipe wall in excellent condition. The polyurethane was replaced and taped into place and the excavation filled in.

In 1994 the inspection was repeated at the same location, using the same procedure, but this time with disappointing results. Significant corrosion was found under the insulation, with corrosion product scale up to 22 mm thick indicating substantial metal loss. Evidently, the 1990 patch repairs at the inspection sites had been less than proficient and the brine from the wetted sand had permeated along the pipe wall under the insulation with inevitable consequences. In corrosion, as in so many facets of life, it often pays to leave well alone!

Summary

An important part of managing the overall risk of a pipeline operation involves assessing, and where justified, modifying the corrosion risk. Given knowledge of the pipeline materials, and
A corrosion engineer can predict the modes of corrosion and, very often, make predictions of the probability of, or time to, failure. The existing corrosion control technologies of materials selection, design, coatings and linings, CP, inhibition and process control can be brought to bear as appropriate to lower, or even eliminate, the risk of failure. Some of these corrosion engineering interventions bring with them the need for policing, by means of corrosion monitoring, which is distinct from the activities of inspection.

Overall, the pipeline operator should use corrosion risk assessment as a template for setting in place a corrosion management programme, the object of which is to ensure that corrosion is constrained to an acceptable rate at an economic cost. In particular, it is poor management to spend more on preventing corrosion failures than the predicted cost of the failures themselves.

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