GL Noble Denton

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Ranking Scheme for Prioritising the Inspection of Pipeline Sleeves

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Prepared for:

Robert Owen on behalf of UKOPA RAWG

UKOPA

Pipelines Maintenance Centre
Ripley Road
Ambergate
Derbyshire
DE56 2FZ

Prepared by:

DG Walker

GL Industrial Services UK Ltd trading as GL Noble Denton

Holywell Park
Ashby Road
Loughborough Leicestershire
LE11 3GR
United Kingdom

Tel: +44 (0)1509 28 2000
Fax: +44 (0)1509 28 3118

E-mail: david.walker@gl-group.com

Website: www.gl-nobledenton.com

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Robert Owen on behalf of UKOPA RAWG	UKOPA Pipelines Maintenance Centre Ripley Road Ambergate Derbyshire DE56 2FZ

Executive Summary

Sleeves have historically been installed to provide additional protection for pipelines that cross traffic routes (including roads, railways, and water courses) or traverse areas with high population densities. Sleeves were predominantly constructed from steel or concrete, and incorporated various designs of end seal and annular fill materials.

Since the publication of sleeve guidelines in 1972, sleeves were designed to three classes:

> Class 1 – To protect the public or some other installation from the consequences of failure of the pipeline
>
> Class 2 – To protect the pipeline the carrier pipe against outside interference
>
> Class 3 – To facilitate the construction of the pipeline

In order to maintain compliance with the Pipeline Safety Regulations 1996, it is necessary to ensure that regular maintenance and inspections are carried out on transmission pipelines and ancillary equipment to confirm they are fit for purpose.

The primary maintenance survey to give a health check on high pressure pipelines is in the form of in-line inspection (ILI) using intelligent pigs. This type of survey gives a detailed report of the state of the pipeline and can be used to give a reliable view of the condition of the pipeline within sleeved areas. These surveys are carried out on a risk based frequency, which is typically at 15 year intervals.

Carrying out inspection of sleeves installed on un-piggable sections of pipeline, however, proves more challenging, as direct access to the sleeved section is often required to obtain a reliable view of pipeline condition.

Due to issues concerning the integrity management of sleeves, and the pipelines within sleeved sections, the United Kingdom Onshore Pipeline Operators' Association (UKOPA) risk assessment working group have begun an initiative to develop a consistent sleeve management strategy. UKOPA requested that GL Noble Denton prepare a proposal to develop a simple risk-based prioritisation scheme for sleeves, using high level information available without site visits, which would form the basis of a programme of work for the assessment of each sleeve using the new maintenance algorithms being developed.

The pipelines of particular interest are major accident hazard pipelines (MAHPs). The vast majority of the MAHPs operated by UKOPA members (by length) are high pressure natural gas transmission pipelines and most of the sleeves of interest are associated with these pipelines. Therefore, the proposed approach to risk prioritisation, as described in this report, concentrates on public safety risk.

Historical incident data and engineering construction data have been used to propose criteria that can be used to estimate the importance on inspecting the condition of pipelines within sleeves on piggable and non-piggable pipelines. These features have been given a weighting based upon historical data and engineering judgement in order to provide a numerical scheme to rank the importance of inspecting the pipeline within a sleeve. Because much of the analysis is based upon generic data, it is expected that, on occasion, this ranking scheme would be superseded by site specific engineering judgement. For example, if it were known that a sleeve was intermittently filled with water, this could be important to inspect.

The engineering judgement within this model could be tested further by analysing in-line inspection data (from piggable pipelines) for the size and occurrence of corrosion defects observed within sleeved sections of pipeline relative to the unsleeved sections of pipeline. It is recommended that UKOPA considers performing this type of analysis.

Contents

1 Introduction

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Since the publication of sleeve guidelines in 1972, sleeves were designed to three classes:

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In order to maintain compliance with the Pipeline Safety Regulations 1996, it is necessary to ensure that regular maintenance and inspections are carried out on transmission pipelines and ancillary equipment to confirm they are fit for purpose.

The primary maintenance survey to give a health check on high pressure pipelines is in the form of in-line inspection (ILI) using intelligent pigs. This type of survey gives a detailed report of the state of the pipeline and can be used to give a reliable view of the condition of the pipeline within sleeved areas. These surveys are carried out on a risk based frequency, which is typically at 15 year intervals.

Carrying out inspection of sleeves installed on un-piggable sections of pipeline, however, proves more challenging, as direct access to the sleeved section is often required to obtain a reliable view of the pipeline's condition

Due to issues concerning the integrity management of sleeves, and the pipelines within sleeved sections, the United Kingdom Onshore Pipeline Operators' Association (UKOPA) risk assessment working group have begun an initiative to develop a consistent sleeve management strategy.

An initial workshop was held on 23rd November 2010 to draw on delegate experience aiming to identify all of the issues and challenges facing the members' own integrity management activities for sleeved pipelines. A second workshop was held on 17th March 2011, to focus on the development of a new sleeve maintenance algorithm. A summary of the discussions that took place during the workshop including a review of the outcomes and ongoing actions to continue the development of the sleeve management strategy was recently circulated to UKOPA members.

However, the application of the maintenance algorithm will require site-specific and pipeline-specific details to be gathered first. The process for prioritising sleeves for subsequent review and remediation was discussed during the workshop. The demand throughout the group for a prioritisation process was mixed, mainly due to some organisations having large sleeve populations (order of 1000's), whilst others had relatively small sleeve populations (order of 10's), and as such have less need for a prescribed prioritisation process. For companies with very large numbers of pipeline sleeves in operation, gathering the necessary details including an initial condition assessment of individual sleeves (e.g. the ability of sealed sleeves to hold nitrogen pressure or the configuration of cathodic protection) may be an onerous and time consuming task.

It was concluded that a risk based scoring process would be beneficial which would identify which sleeves are highest risk, based upon their design and configuration. Therefore, UKOPA requested that GL Noble Denton prepare a proposal to develop a simple risk-based prioritisation scheme for sleeves, using high level information available without site visits, which would form the basis of a programme of work for the assessment of each sleeve using the new maintenance algorithms being developed.

The pipelines of interest are major accident hazard pipelines (MAHPs). The vast majority of the MAHPs operated by UKOPA members (by length) are high pressure natural gas transmission pipelines and most of the sleeves of interest are associated with these pipelines. Therefore, the proposed approach to risk prioritisation concentrates on public safety risk.

Other risks may be relevant in special cases; for example, there may be a significant risk of business interruption if the pipeline sleeve is located at a critical point on a pipeline network and a failure at that location could result in a loss of supply. In the case of pipelines transporting fluids other than natural gas, there may be a significant environmental risk; for example contamination of water supplies where a sleeve has been used at a river crossing. Such business risks and environmental risks are not addressed here – if required, the prioritisation scheme could be modified to take these additional effects into account, with a weighting applied to each type of risk to be agreed by discussion with UKOPA members.

Layout of the report follows the following scheme:

- A high level overview of the principles of the Sleeve Inspection Prioritisation Scheme is presented
- A review is made of the historical methods that have been used to construct sleeves
- A review is made of issues arising and incidents that have occurred related to pipelines within sleeves
- The Sleeve Inspection Prioritisation Scheme itself is then outlined along with an explanation of the weighting factors used and magnitude of the values for the different variables within the weighting factor

Terminology

For the purposes of this report:

- “Sleeve” is used in this report to represent the structure around the pipeline. In the USA the equivalent terminology is “casing”.
- “Pipeline” is used to represent the pipe within the sleeve. Other terminology for this pipe includes “carrier pipe” and “line pipe”.
- Pressures are gauge pressures unless explicitly stated otherwise.

2 Methodology

The proposed approach will develop a measure of the likelihood that a loss of containment occurs (incorporating the understanding gained from the work already underway for UKOPA of the integrity management of sleeves) coupled with a measure of the consequences should loss of containment occur.

Development of the scheme included the following stages:

1. UKOPA Hazard identification and risk factors

Discussions with participants at the second UKOPA workshop identified the following initial list of factors that could be considered in a risk-based prioritisation scheme:

Table 1: Initial list of factors identified to be considered in prioritising sleeves for review/remediation

Prioritisation Process Component	Details/Risk Factors
Piggable/Un-piggable	Ability to inspect and identify corrosion activity
Pd^2 design factors	Risk based
Annular fill	Nitrogen, grout, other, or unfilled
Sleeve location	Population or traffic density
Inspection history/design records	Availability of records, knowledge of design and past performance of protection systems
CP compliance	Capability of the system to provide protection
Depth of cover	Increasing depth of cover increases difficulty of remediation

However, not all of these may be readily available without a site visit and/or excavation, for example depth of cover or the nature of annular fill. Additional factors were added to the scheme as were identified during the development of the prioritisation scheme.

2. Failure probability (frequency)

For a section of pipeline within a sleeve, the main concern is that the presence of the sleeve could increase the threat from external corrosion, which is difficult to detect because of the presence of the sleeve, especially for “un-piggable” pipelines that cannot be inspected internally. The presence of the sleeve offers physical protection for the pipeline against the threat of third party damage and is assumed to have no bearing on the other main threats to pipeline integrity – e.g. ground movement, material/construction faults or internal corrosion. As a minimum, the UKOPA workshop identified that those factors that would be considered as relevant to the failure probability component of a high level risk prioritisation scheme would include:

- Wall thickness (increasing wall thickness reduces the likelihood of corrosion failures)
- Piggable/un-piggable (internal inspection should detect corrosion before failure)
- Status of Cathodic Protection (CP) (pipelines would be assumed to have adequate CP in place, but where this is known not to be the case, an increased factor may apply)

Pipeline failure frequencies would be adapted to allow for the potential for different sleeve configurations to affect the pipeline beneath.

However, the UKOPA workshop had identified that there were a number of design factors (such as fill type) where the impact/consequences of certain design parameters on sleeve/pipeline integrity are unknown. It was also noted that a range of sleeve designs have been used (varying fill materials, differences in CP configuration, etc.) but the knowledge was not available to identify what would be considered to be best practice. Consequently, engineering judgement has been used to derive a weighting factor for these parameters.

It is also noted that US incident data indicates that pipes can fail within sleeves for causes other than corrosion, such as defective welds on the pipeline or mechanical damage to the pipeline.

3. Failure consequences

For the purpose of a simple high level risk-ranking scheme, the measure of consequences will be based solely on the predicted effects of ignited releases. This will include three main components:

1. The size of the area affected by a fire within which people would be harmed
2. The probability that ignition occurs
3. The number of people exposed to the hazard (taking account of both permanent populations and transient populations at traffic routes)

In general, the consequences of full bore pipeline ruptures are much greater than for leaks. However, there is no historical experience of full bore ruptures in the UK as a result of external corrosion of the pipeline, which has been identified as the threat most likely to be influenced by the presence and condition of the sleeve.

4. Inspection prioritisation

The prioritisation for inspection score is determined by combining a factor representing the likelihood of an escape with a factor representing the relative consequences of the escape.

In the methodology outlined in this report these scores are presented as a numerical value. However, it should be emphasised that the scores are an empirical, non-linear, ranking of the likelihood and consequences of a spontaneous escape from a pipeline following corrosion of a pipeline within its sleeve.

Development of the Ranking Scheme

The ranking scheme has used a combination of sources to identify those features of the sleeving that could indicate a potential problem and the magnitude of that problem. These sources included:

- Incident data was used to identify factors that had contributed to previous incidents.
- US inspection data regarding observed problems with pipeline sleeves.
- Historical construction data was used to identify typical types of sleeves that could be in use in different time periods.
- Statistical pipeline failure data was used to identify broad trends of failure mechanism.

It is expected that following production of an initial draft report, the weighting factors used within the Ranking Scheme will be reviewed by a workshop.

3 Notes on Historical usage of Sleeves

This section outlines the key features of construction practices for pipelines within sleeves that have been applied in the UK and USA.

3.1 UK

Sleeves were primarily used in the UK from the late 1950s through to around 1990. In this time period there were a number of documents produced by IGEM (Institution of Gas Engineers and Managers) providing guidance to the usage and construction, as indicated in the figure below. A summary of the key information in these documents is then provided.

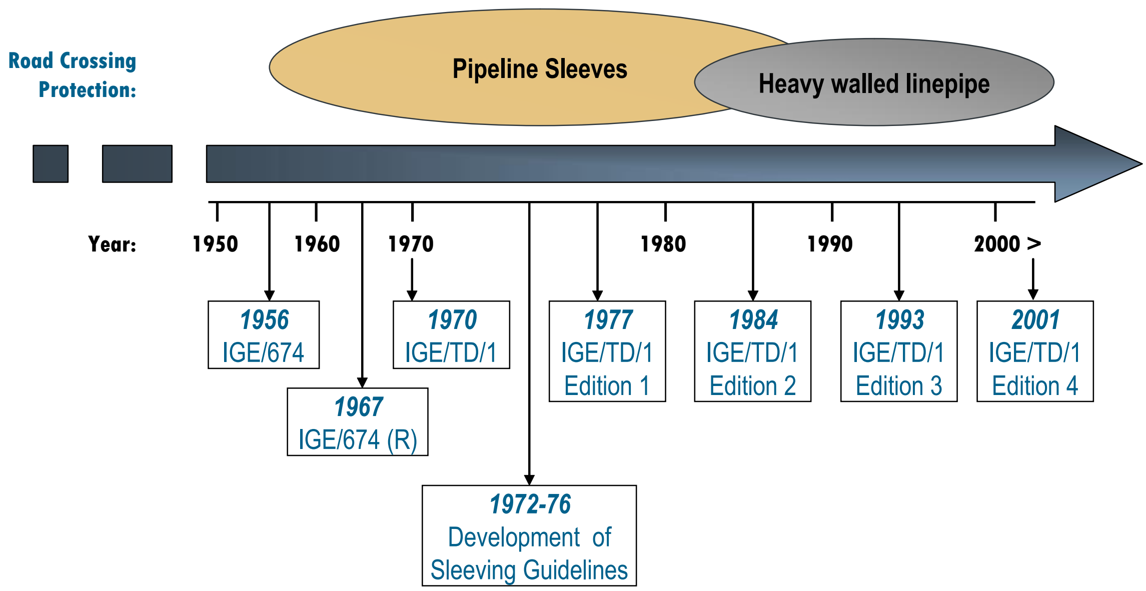

Figure 1: Development of IGE/TD/1

Documents 1950 to 1977

1956 - IGE/674: Recommendations Concerning the Installation of High Pressure Pipelines

When the pipeline has to cross a carriageway, railway, or watercourse the method adopted is a matter for individual design, after consultation with all the authorities concerned. When a pipe is protected by sleeving it with a large size tube, the annular space should be vented and fitted with a flame arrestor.

1967 - IGE/674 Re-Print: Recommendations Concerning the Installation of High Pressure Pipelines

Crossings of railways, roads, rivers, streams, can be sleeved in pre-cast concrete or steel pipe or other materials. The annular space should be filled with a suitable material or sealed and vented to atmosphere.

1970 – IGE/TD/1: Steel Pipelines for High Pressure Gas Transmission

For working pressures above 350 lbf/in^2, pipelines laid in roads should be sleeved; where such pipelines are laid in close proximity to roads or railways, consideration should be given to sleeving, having regard to the density of traffic.

All crossings of roads and railways should be steel sleeved for working pressures exceeding 350 lbf/in^2. The sleeve should extend for a suitable distance either side.

1972 – Provisional Section on Pipeline Sleeving (Addition to TD/1)

This document introduced three classes of sleeves:

- Class 1 Sleeves required to protect the public, or judged desirable to protect some other installation, from the consequences of failure of the carrier pipe. Also serve to protect the carrier pipe from outside interference.
- Class 2 Sleeves provided in order to protect the carrier pipe from outside interference
- Class 3 Sleeves installed only to facilitate the construction of the carrier pipe.

1976 to 2000

IGE/TD/1:1977 Comm 674ABCD - Section S: Pipeline Sleeving

Section S: Pipeline Sleeving restated the sleeve design classes:

Class 1 sleeves were used to provide protection in the event of the pipeline within the sleeve leaking. It is noted that within IGE/TD/1:1977 the minimum distance between a building and a Class 1 sleeved pipeline is markedly less than for an unsleeved pipeline, particularly at the higher operating ranges.

Class 2 Sleeves could be used to provide protection for pipeline operating at pressures up to 350psig (24barg).

R = Recommended System (*NB* The table should be read from left to right to find the recommended system in each set of circumstances.)
A = Alternative System only to be used if recommended system cannot reasonably be applied.
X = Unacceptable System.

		Sleeve Material (S.4.1)					
		Steel			Concrete		
		End Seal Type (S.4.7)					
Sleeve Class	Application (S.2.2)	Rigid	Flexible	Shuttering	Rigid	Flexible	Shuttering
1	To meet the requirements of 5.5.1, 5.5.2.1 or 5.7 to give protection against consequences of carrier pipe failure. Also to protect carrier pipe against outside interference.	R	A	A	X	X	X
2	To meet the requirements of 5.5.2.2 to protect the carrier pipe against outside interference.	R	A	A	X	X	A
3	Required only to facilitate construction of the carrier pipe.	A*	A	A	X	X	R
Method of Corrosion Control (S.7)	Annular Fill (S.3.3)						
Inert Environment Only	Nitrogen (S.3.3.3) (S.7.2)	R	A	X	X	X	X
Combination of: Coating, Environmental control, Cathodic protection	Cementitious (S.3.3.4) (S.7.3)	X	X	A	X	X	R
	Others (S.3.3.5), *eg* Bentonite (S.7.4), grease/oil, foam plastics	A	A	A	X	X	A

* Where a steel sleeve is used it should preferably have rigid end seals and nitrogen fill.

Figure 2: Extract from IGE/TD/1:1977

Section S: Pipeline Sleeving gives guidance on

- Sleeving of existing pipelines
- Sleeve construction
- Pipe spacers
- Annular fill and corrosion control
- Maintenance of sleeved lengths.

Key points on the usage of sleeves are summarised below:

- Crossing of roads and railways should be steel sleeved for working pressures exceeding 350 psig (24barg). The sleeve should extend for a suitable distance on either side.
- Class 1 Sleeves passing closer to buildings than the proximities specified in Table 3 of IGE/TD/1 should be of such a length that the distance of the unprotected pipeline at the sleeve ends complies with those given in Table 3.

- Special consideration should be given to Class 1 sleeves protecting pipelines operating at pressures above 350psig in Type S areas.
- Sleeves crossing roads and railways should extend to at least the boundary. Where the density of road and rail traffic is particularly high or there is a risk of interference, consideration may be given to extending the sleeve beyond the boundary. The distance given in Table 3 of IGE/TD/1 is the maximum required from the sleeve end to the road or railway running track.
- The length of class 2 and class 3 sleeves may be at the discretion of the Engineer with due regard to the circumstances leading to the necessity for sleeving.

Table 2: IGE/TD/1 Minimum distances (in feet) from buildings of pipelines

Outside diameter (inches)		Maximum working pressure (psig)				
		100 (7barg)	100 to 350	350 (24barg)	350 to 1000	1000 (70barg)
Minimum	**Maximum**	**2**	**3**	**4**	**5**	**6**
	6 5/8	10 (3m)	Liner interpolation between columns 2 and 4	15 (4.6m)	Liner interpolation between columns 4 and 6	75 (23m)
6 5/8	12 ¾	10 (3m)		40 (12m)		100 (30m)
12 ¾	18	10 (3m)		60 (18m0		125 (38m)
18	24	15 (4.6m)		80 (24m)		160 (49m)
24	30	20 (6m)		100 (30m)		200 (61m)
30	36	20 (6m)		125 (38m)		250 (76m)

Table 3: IGE/TD/1 Minimum distances (in feet) from buildings of sleeved or periodically inspected pipelines

Outside diameter (inches)		Maximum working pressure (psig)				
		100 (7barg)	100 to 350	350 (24barg)	350 to 1000	1000 (70barg)
Minimum	**Maximum**	**2**	**3**	**4**	**5**	**6**
	6 5/8	10 (3m)	Liner interpolation between columns 2 and 4	10 (3m)	Liner interpolation between columns 4 and 6	10 (3m)
6 5/8	12 ¾	10 (3m)		10 (3m)		15 (4.6m)
12 ¾	18	10 (3m)		10 (3m)		20 (6m)
18	24	10 (3m)		15 (4.6m)		25 (7.7m)
24	30	10 (3m)		15 (4.6m)		30 (9m)
30	36	10 (3m)		20 (6m)		40 (12m)

In relation to corrosion of the pipeline within the sleeve, the key points of this guidance are outlined below:

General

- The coating of steel sleeves and integral pipework should be of the same quality as the rest of the pipeline
- Where end seals contain metallic parts they should be protected against corrosion by coating and cathodic protection suitably linked into the protection system for the pipeline or for the sleeve.

- Depending upon whether, or not, it is required for the pipeline and the sleeve to be electrically isolated the spacers may be of plastics, coated steel or steel.

Nitrogen filled annulus within a steel sleeve.

- The pipeline coating within the sleeved length should be as far as practicable to the standard specification of the pipeline.
- Cathodic protection of the sleeve will be provided by the pipeline CP system when the sleeve ends are sealed with forged steel rigid end-seals. When a non-metallic rigid end-seal is used, the cathodic protection will be obtained through electrical connections to the pipeline, and thus the pipeline CP system. Similarly if a flexible end seal were used an electrical connection would be applied between the sleeve and the pipeline.

Cementitious fill – steel or concrete sleeve

- Because of the practical difficulties in ensuring the annulus is completely filled, corrosion control is through a combination of pipe coating, annular fill and cathodic protection.
- The pipeline coating within the sleeve should be augmented by a second, site-applied external coat that would adhere to the previous coating.
- Where a steel sleeve is used with a cementitious fill, the metal sleeve should be electrically isolated from the pipeline and/or a cathodic protection system independent of the pipeline system should be provided for the sleeve.

Bentonite fill – steel or concrete sleeve

- The pipeline coating within the sleeve should be augmented by a second, site-applied external coat that would adhere to the previous coating.
- Where a steel sleeve is used with a cementitious fill, the metal sleeve should be electrically isolated from the pipeline and/or a cathodic protection system independent of the pipeline system should be provided for the sleeve.

Where sleeves are being protected by a sacrificial anode, in order to minimise the possibility of corrosion on the pipeline, the potential on the pipeline should be more negative than the potential on the sleeve and that current output from the anode should be minimised.

1984 – IGE/TD/1 Edition 2

- High Density Traffic Routes
    a. Utilise pipe with a nominal wall thickness of not less than 11.91 mm, OR
    b. Be steel sleeved in accordance with Class 1
- Other Traffic Routes

a. Utilise pipe with a nominal wall thickness not less than 9.52 mm, or be provided with impact protection, OR

b. Be steel sleeved in accordance with Class 2.

IGE/TD/1 Editions 3 (1993) and 4 (2001)

- Heavy walled pipeline is recommended for crossings, sleeves should only be used to facilitate construction.
- Construction sleeves should be concrete, however a steel sleeve may be implemented designed to incorporate a nitrogen fill with the use of forged end seals.
- Existing sleeves that meet Class 1 or 2 of Edition 2 may continue to be used to allow the pipeline to operate up to its original design factor.

3.2 USA

This section presents information regarding how sleeves are and have been constructed in the USA. Within some of these documents there was mention of problems with the designs used. These issues are recorded within this section, although further comments on these issues are made in subsequent sections on pipeline integrity.

Casing Discussion, John Williams, The Tapecoat / Royston Company

This presentation provides information on recent and historical practices within the USA and provided suggestions on how to address the issue of pipeline corrosion within sleeves.

In the USA casing installation began for the following:

- Potential for stress damage to the pipeline caused from heavy loads, trains and trucks.
- Unstable soils
- Corrosion caused by oxygen concentration cells because of road building processes
- Ease of removal and replacement of pipelines
- Venting of dangerous gasses away from road side.

Current practice guidance includes NACE SP0 – 200 - 2008

- 3.2.3 Uncoated casing pipe is normally used. The use of coated or non-metallic casing pipe is not recommended, due to potential shielding problems.
- 3.2.4 Vent pipes should be installed on both ends of a casing.
- 3.2.5 The casing vent hole should be at least one-half the diameter of the vent pipe (25 mm [1.0 in] minimum). The casing vent pipe should be a minimum of 50 mm (2 in) in diameter.

- 3.2.6 The casing and carrier pipe shall be properly supported for the entire length of the pipe, especially near the ends, to prevent sagging, metallic contact, and to avoid carrier pipe stress. Refer to Paragraphs 4.3 and 4.4.
- 3.2.7 Properly designed casing end seals shall be installed to prevent ingress of water and debris.

End-Seal Types

- Previously: Concrete or Enamel w/ Rope
- Today: Wraps, Shrink Sleeves and Link Seal types.

Spacer Types

- Previously: Metallic, Concrete coated pipe, Wooden
- Today: Plastics.

Typical mechanism of a short between pipeline and sleeve include:

- End seals crush or deteriorate allowing water to enter
- Pipe spacers crush or wrong type used such as metal or metal components
- Test leads make contact in the test station
- Vent pipes connected to the pipeline or supported on the pipeline
- Other possible problems such as metal tools left inside the pipe.

J Williams notes that end seals are rarely adequate to prevent entry of water etc. into the annulus between the pipeline and sleeve and once water enters a casing:

- Corrosion can develop. Even if the casing is not shorted, the current may not be enough to adequately protect the pipe.
- Any current passing through the casing will only provide some protection to that part of the pipe immersed in the water.
- No way to properly monitor the potential inside the casing.

J Williams notes that one way of protecting a pipeline where there is an electrical short between the pipe and sleeve is to fill the annulus with an inert material such as hot wax, cold wax or a gel.

Corrosion Engineers Counter Point– Casings over Pipelines Passing Under Highways, James B. Bushman, Bushman & Associates, Inc. Ohio USA

This presentation outlines issues associated with typically designed sleeves in the USA and proposes a protocol for addressing the issue. Key points from this presentation are outlined below.

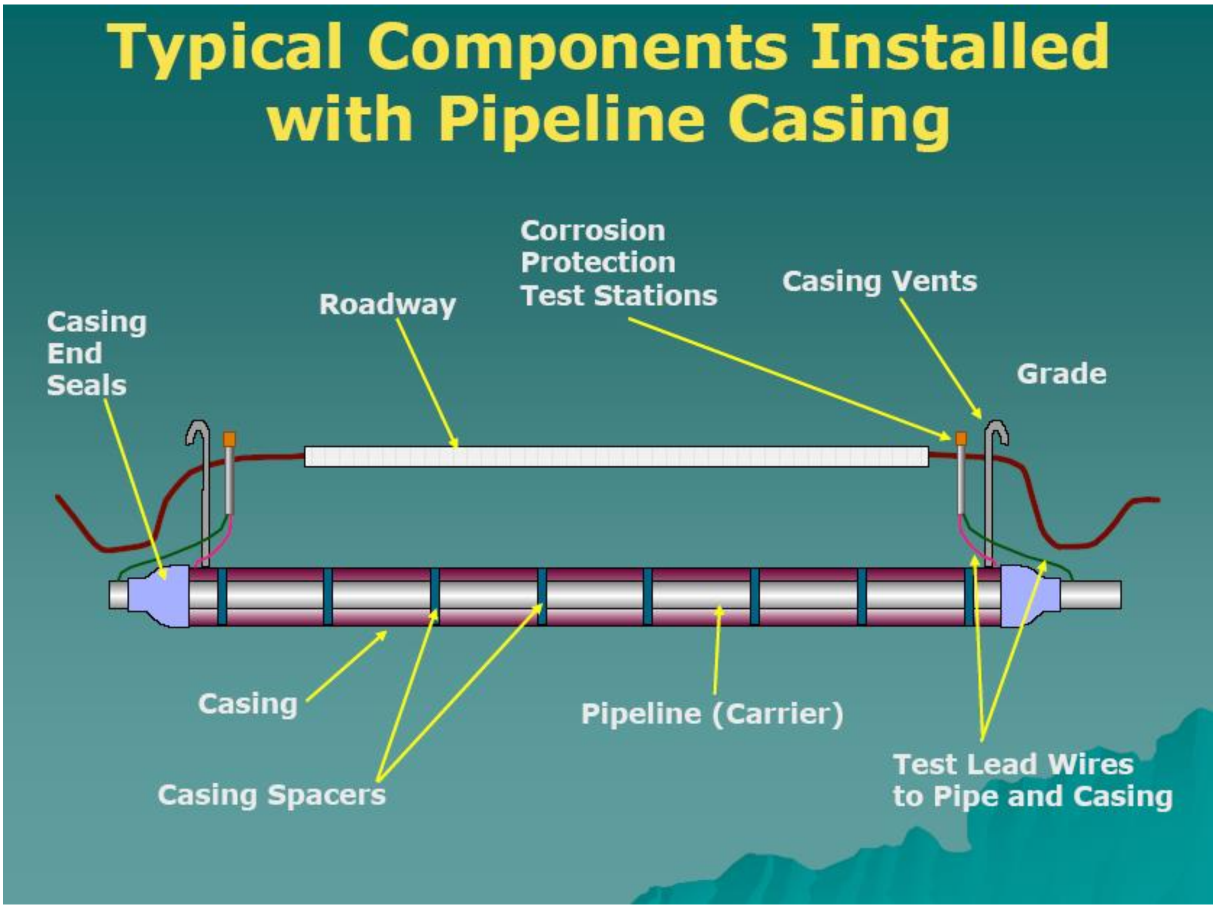

Figure 3: General layout

Typical problems with casing spacers are:

- Slide during installation
- Break
- Pads wear off

All of above can cause a short between the pipeline and sleeve, stress on the pipeline and jamming during alteration, removal or installation work.

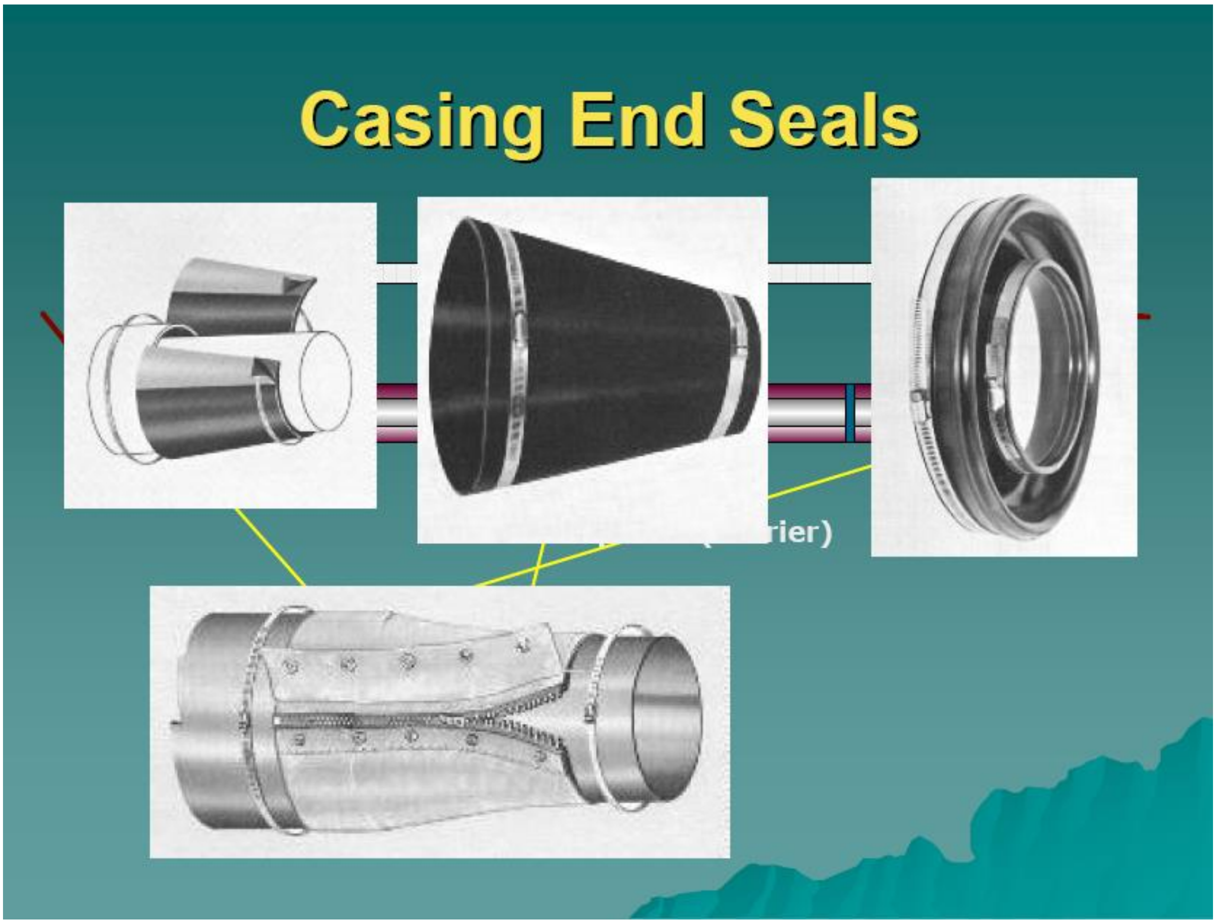

Figure 4: End seals

Typical problems with end-seals are:

- Sealing bands corrode and/or break
- Boots (sealing gasket) puncture and leak
- Differential movement of pipeline and sleeve loosens boot.

All the above can allow moisture penetration between pipeline and sleeve (annulus), which can lead to future pipeline leaks.

Typical problems with vents are:

- Physical damage prevents original function of venting any gases that had leaked into casing, moisture evaporation and leak monitoring
- Corrosion damage typically at weld to sleeve.

Moisture in the annulus can lead to future pipeline leaks.

NACE SP0200-2008 Discussion, PHMSA Pipeline Casing Workshop, Chicago, IL July 2008

This presentation by NACE commented on the USA practice and showed examples of sleeves in the USA. NACE indicated that the current practice of installing cased carrier pipe had changed only slightly since the beginning of its use. External loading of the carrier pipe has been eliminated by the installation of heavy-wall casing pipe, and isolating spacers are used to prevent electrical contact between the casing and the carrier pipe. End seals are used to keep mud and water out of the annular space between the carrier pipe and casing.

Figure 5: Pipeline and sleeve (NACE)

Figure 6: Sleeve extension during construction (NACE)

Figure 7: Sleeve extension completed (NACE)

Union Pacific Railroad

This drawing shows the typical layout of a pipeline within a sleeve for a railroad crossing, including wall thicknesses of outer sleeve:

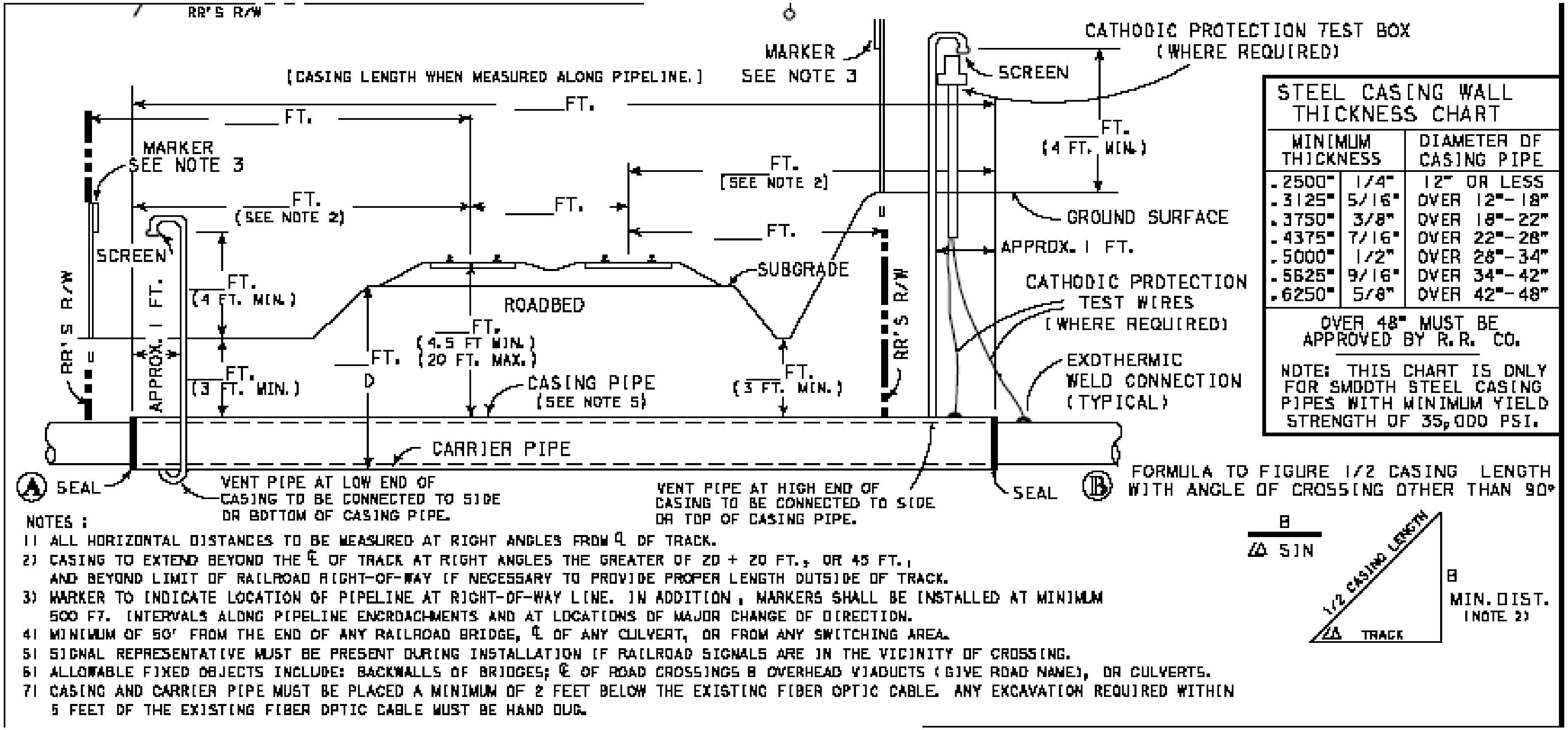

Figure 8: Union Pacific Railroad drawing

3.3 Comment

The IGE documents and presentations on USA practice show that there were differences between the practices adopted in the USA and UK in terms of the construction of sleeves around pipelines. These differences would relate to the relative likelihood of the pipeline within the sleeve failing. It is also worth noting how the reported incidents on the USA pipeline can be related to the typical USA construction practices.

It is also noted that the design of sleeves recommended by IGE/TD/1 in 1956 was similar to that used in the USA for railway and road crossings. However, by 1967 design modifications were being introduced in the UK including filling the annulus with a suitable material.

4 Historical Data on Pipeline Integrity

This section examines incidents that have already happened on high pressure gas and liquid pipelines as well as other analyses of factors affecting the integrity of pipelines within sleeves.

4.1 Previous incidents

Appendix A presents information about previous incidents where the pipeline has leaked within a sleeve. These incidents occurred in the USA where a sleeve would typically consist of a steel pipe around the pipeline that had some sort of end seal (such as a gasket) and vent pipes to atmosphere. Cathodic protection would typically be applied to the pipe.

Analysis of the incidents identified immediate issues around:

- Damage to pipeline coating
- Lack of CP protection to pipeline within the sleeve
- Entry of water into annulus between sleeve and pipeline
- Entry of air into the annulus via the vent pipes or with ground water.

It was also noted that incidents occurred on pipelines where there were corrosion anomalies along the whole pipeline and not just within the sleeve.

4.2 Other analyses of pipeline integrity within sleeves

This section summarises the findings of other analyses undertaken to assess the issues around pipeline failures within sleeves.

Cased Pipeline Integrity Assessment Workshop, Rosemont, Illinois, 15 and 16 July 2008

Following the Delhi Louisiana incident in 2007, in a 2008 sleeve assessment workshop the PHMSA identified the following integrity threats to sleeved pipelines:

External Corrosion

- Failed end-seals traps moisture inside sleeve.
- Coating damage leads to corrosion. Coating damage may be caused by poor construction techniques and lack of centralizers. If the pipeline is completely isolated from the sleeve and there are no coating defects there is no threat from external corrosion. If there are coating defects atmospheric corrosion is a concern as is a Direct or Electrolytic short.
- Direct (hard) Short is a metal to metal contact between the carrier pipe and the sleeve caused by misalignment, settling or movement of the pipeline or sleeve. Direct “hard” contacts may drain cathodic protection potentials away from carrier pipe to casing and thus lower potentials to where corrosion can occur.
- Electrolytic (resistive) Short is a contact between pipeline at a coating defect to the sleeve via an electrolyte, i.e. water, soil, debris, etc. Typically caused by a failure of the casing end seals. Sometimes due to debris getting into casing via vents. May cause corrosion cell formation.
- Atmospheric Corrosion.

Internal Corrosion

- Sleeves are generally low points, such as under highways or rail crossings, which could accumulate liquids.

Stress Corrosion cracking

- Same as other pipe.

Seam Weld issues

- Same as other pipe.

Girth weld issues

- Same as other pipe.

Construction issues

- May be increased due to alignment issues.

Outside Force Damage [i.e. Excavation Damage]

- Threat not eliminated but reduced, there have been instances of third party damage to carrier pipes in casings but they are rare.

Statistical analysis of external corrosion anomaly data of cased pipe segments Prepared for The INGAA Foundation, Inc. by Southwest Research Institute, F-2007-10, December 2007

This report analysed data provided by a number of pipeline companies on corrosion anomalies detected by in-line inspection. Key sections of the report are presented below:

- Many factors can affect the integrity of cased pipe segments, including: differences in design of casings, steel or weld types, year of installation, extensions of casings to accommodate road work, historical interruptions of CP, historical leaks, historical shorts and clearance of shorts, bare or coated carrier or casing pipes, types and conditions of coatings on either carrier or casing pipes, local weather conditions, seasonal changes (temperature and rain falls), soil electrolyte corrosivity, local atmosphere corrosivity related to geographical locations such as coastal or grass/forest lands vs. desert, industrial areas vs. agricultural areas, and issues such as stray currents, third party damage, natural disasters (e.g., earthquake, hurricane, flooding), etc.
- For the total of 2733 casings received for this study, only slightly less than 10% of them (272 casings) contain anomalies, on the carrier pipes, with a depth of 20% wt (wall thickness) or greater. Only one cased pipe segment contains an anomaly whose depth is greater than 80% wt.
- The preferential location of anomalies on carrier pipe inside casings is 2% of the casing length, or approximately 3 feet on average, from either end of the casing. Beyond 3 feet, the peak anomalies are relatively uniformly distributed. This preferential location contains 25% of the peak anomalies; the peak anomaly has over 10 times likelihood to be located here than any other place on the carrier pipe with the same area.
- The new analysis of the OPS 1988 report data and the analysis of new data provided for this study show that shorted-casings are significantly more susceptible to corrosion than that of non-shorted casings. In reaching its conclusion: “A shorted casing does not enhance or reduce corrosion activity on carrier pipe,” OPS neglected the fact that the non-shorted casings were significantly more numerous than the shorted casings.

- One operator's field data for a limited number of 139 casings suggests that metallically shorted casings or electrically shorted casings are more prone to resulting in carrier pipe corrosion than clear casings (no electrolyte in the annulus).

5 Sleeve Inspection Prioritisation Scheme

5.1 Introduction

The objective of the scheme is to estimate the relative importance of inspecting the sleeve based upon the likelihood of an escape occurring and the potential consequences. The higher the value scored by the scheme the more important it is to monitor/inspect the sleeve.

In order to make the scheme manageable only those factors that provide a viable means of differentiating between the different sleeves are considered.

Factors where the potential effect is essentially fine tuning/background noise or where the effect is swamped by the variability of the data are not considered.

The prioritisation scheme essentially assumes that the fluid being transported in the pipeline is natural gas. However, pipelines may be used for other fluids; consequently, the prioritisation would need to be reviewed for other fluids or applied bearing in mind the following correlations:

- Estimated that for ignited releases all hydrocarbon gaseous fuels are equivalent.
- Considered that for flammable gas/vapour releases the hazard associated with the material is related to volume released, but cannot be directly compared between different materials. For example non-flammable gases may have toxic or asphyxiant or null hazards associated with them.
- Considered that flammable liquid releases are essentially an environmental hazard and if ignited would not cause significant fatalities.
- Considered that non-flammable liquid releases are an environmental hazard and cannot be directly compared to the safety hazards considered.

It is noted that the sleeve inspection prioritisation scheme produces a numerical output, whereas most of the information pertaining to the usage of sleeves is presented qualitatively, for example in:

- IGE/TD/1:1977 Comm 674ABCD - Section S: Pipeline Sleeving
- UKOPA Workshop Summary: Development of Sleeve Management Strategy, S Jackson, GL report 11050, 2011.

Consequently, empirical engineering judgement has been used to convert subjective opinions into numerical factors.

It is noted that IGE/TD/1 is primarily applicable to natural gas pipelines where sleeves have been constructed after 1976. However, many natural gas pipelines were constructed before this time and pipelines may have been built to transport other fluids and to other standards. Thus the configurations identified in IGE/TD/1 may not be the only configurations that are in current usage.

Where numerical data was found e.g. EGIG statistics, these have been referenced in generating the numerical factor.

5.2 Hazard being considered

5.2.1 Identification of the hazard

It is considered that the primary concern is the ingress of water and oxygen into the annulus between the pipeline and the sleeve with the resulting possibility of corrosion of the pipeline.

Rainwater would typically have oxygen dissolved in it and as it percolates through the soil this oxygen could be removed from the rainwater. If the transit time to the pipeline is relatively long most of the oxygen in the water may have been removed and the soil around the pipeline may be essentially anaerobic.

Aggressive species such as soluble sulphate and chloride ions could dissolve in the ground water and thereby migrate into the annulus.

If ground water containing oxygen were entering the annulus, it would be considered that the likelihood of corrosion of the pipeline (and the surrounding sleeve if ferric) would be proportional to the volumes of oxygenated water entering the annulus and thus would be related to how well the ends of the sleeve were sealed. A sleeve that was not sealed at the end would enable significantly more water to enter an empty annulus than one where the ends had a small leak, which in turn would be more problematic than a sleeve that was water tight sealed at the ends. Filling the annulus with an inert material such as cement grout may result in water migrating through cracks in the annulus, but the rate of such water movement would be expected to be relatively low, possibly equivalent to that produced by a leaking end seal.

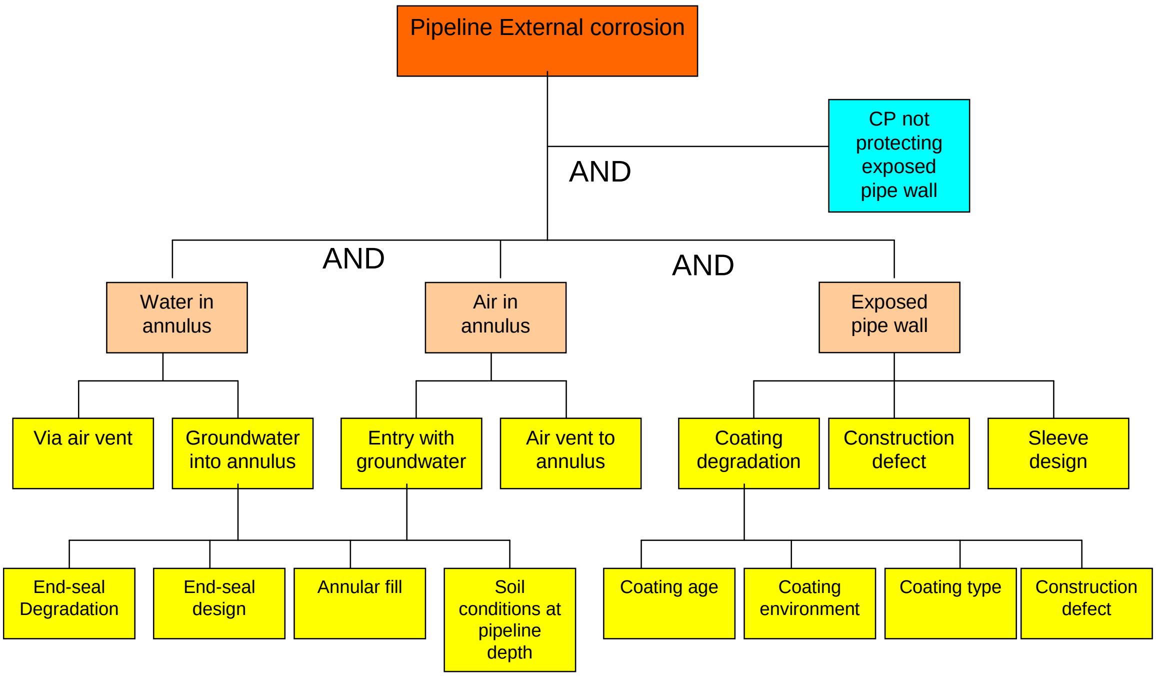

Figure 9: General process being considered in the ranking scheme

5.2.2 Data on corrosion holes

UKOPA data has shown that the historical corrosion rate for holes in UK pipelines varies with a number of factors including;

- Pipe wall thickness
- Date of pipeline construction
- Pipeline coating

IGEM/TD/2 indicates that to date there is no operational experience of rupture failure of pipelines through external corrosion in the UK. This document gives failure frequencies (per 1000 km per year) of pinholes and holes for pipelines of different wall thicknesses.

Table 4: IGEM/TD/2 Failure frequency through external corrosion

Wall thickness (mm)	Failure frequency (per 1000 km per year)			
	Pinhole (0 to 6mm diameter)	Hole (6mm diameter to full bore)	Rupture (full bore or above)	Total
<5	0.262	0.04	0	0.302
> 5 <= 10	0.031	0.015	0	0.046
>10 <=15	0	0	0	0
>15	0	0	0	0

IGEM/TD/2 provides further modifiers to these failure frequencies. For pipelines commissioned before 1980 it is suggested that the failure rates in Table 4 be used unless corrosion protection measures have been applied. For pipelines of wall thickness up to 15mm and commissioned after 1980 with corrosion protection applied these values can be reduced by a factor of 10. For pipelines with wall thicknesses above 15mm the failure rate can be assumed to be negligible.

It is noted that in the UKOPA report regarding the size of the 37 reported external corrosion holes:

- 76% were pinholes (up to 6mm diameter)
- 22% were holes of 6 to 20mm diameter
- 3% were 110mm diameter to full bore.

The one external corrosion hole having a recorded hole size above 20mm occurred on a pipeline that had:

- A construction date of before 1975
- Up to 10mm wall thickness
- Coal tar coating
- Laid in heavy soil.

The corresponding EGIG parameters (as estimated from Figure 30 of the 8th EGIG report) are given below. It is noted that the definition of pinhole and hole vary between UKOPA and EGIG:

Table 5: EGIG Failure frequency through external corrosion

Wall thickness (mm)	**Failure frequency (per 1000km per year)**			
	Pinhole (0 to 20mm diameter)	**Hole (20mm diameter to full bore)**	**Rupture (full bore or above)**	**Total**
<5	0.118	0.002	0	0.120
> 5 <= 10	0.055	0.002	0.001	0.058
>10 <=15	0.002	0	0	0.002
>15	0	0	0	0

It is noted that in the data obtained relating to pipeline failures within sleeves, the leak is generally described as being a pinhole. The one notable rupture was a rupture near Beaumont in 1980 on a section of 30" diameter, 0.375" wall thickness (9.5mm) pipeline within an annular sleeve that was fitted with air vents. In this case it is noted that:

- The rupture location was relatively close to an upstream compressor station, which would have resulted in:
  - High temperature gas within the pipeline within the sleeve and consequently high temperature at the pipe wall
  - Potential disbanding of the coating at this location
  - Potential evaporation and condensation of water within the sleeve.
- There were problems with the CP installation at this location since the pipe was installed in 1953.
- Following the incident many areas of external corrosion were found along the length of the pipeline by in-line inspection.

5.3 Data for the scheme

In order to estimate the relative importance of inspecting a sleeve, in an ideal world detailed data on the pipeline, the sleeve and surrounding ground would be considered. However, it is acknowledged that in practice there is only a limited data set from which to derive the relative ranking. This section outlines the data that it is considered could be available and which it is considered would be unlikely to be available.

5.3.1 Unavailable data

Ground conditions

It is expected that generally there would be no or minimal data available on soil conditions, water tables etc. Consequently these factors are not included in the prioritisation scheme.

Pipeline operating temperature

Incident data and statistical analysis indicate that a high temperature of the fluid (and concomitantly a high temperature of the pipe wall) can contribute to the occurrence of external corrosion of a pipeline. For example, data from CONCAWE presented in 'Performance of European cross-country oil pipelines – Statistical summary of reported spillages in 2005 and since 1971' (CONCAWE Report 4/07, May 2007) presents the following table for corrosion related spillage (over 1m^3) in oil pipelines.

Table 6: CONCAWE data on corrosion related spillage

Corrosion type	Hot products	Cold products	All pipelines
External corrosion	53	46	99
Internal corrosion	1	21	22
SCC	0	4	4

The hot product pipelines comprise a much smaller inventory of pipelines compared to the cold pipelines and thus were considered to be more susceptible to the effects of external corrosion. This report also noted that the size of holes produced by external corrosion tended to be small. In general the spillage rate for hot pipelines was about 10 times those of cold pipelines (See also CONCAWE report 3/11, Statistical summary of reported spillages in 2009 and since 1971).

Of the 71 corrosion related spillages, 24 were related to special features such as road crossings, anchor points and sleeves etc, which were therefore considered especially vulnerable. However, further details are not given of the nature of the special feature, and where it was a sleeve, the type of sleeve etc is not identified.

It is noted that the temperature of the fluid within high pressure gas pipework would typically be close to the surrounding soil temperature apart from locations near compressor stations where the gas is being compressed (with concomitant heating) and near pressure reducing installations (where there is concomitant cooling of gas).

Overall, it is considered that the temperature of the fluid within the pipeline would not normally be known at the location of a sleeve and thus this parameter has not been included.

Unknown data

There are a number of pieces of data that would be useful to a ranking process where it is acknowledged that the data will not be available. These data generally relate to issues that would only be found following an incident and subsequent investigation.

Amongst the pieces of data that would not be expected to have been retained are issues associated with pipe construction, such as damages to the pipe coatings and subsequent repair.

Also there are factors which are unknown and thus could not have been recorded, for example unidentified damage to a pipeline coating within the sleeve.

The application of a parameter that provides a general descriptor of the state of the overall pipeline would allow the sleeve and pipeline combination to be weighted to the parent pipeline and thus facilitate comparison of sleeves on different pipelines. For example an ILI may indicate that the numbers of defects per kilometre are different for different pipelines and this parameter can be used in the relative ranking.

However, with the issue over piggable and un-piggable pipelines as well as changes in ILI techniques, it is considered that there is not a method to compare across pipelines.

5.3.2 Available data

The data that are expected to be available for the sleeves being considered falls into three categories; data associated with the parent pipeline, data associated with the sleeve and data associated with various monitoring and inspection regimes. These data fields are listed below.

It is assumed that the data collected by a TD/1 survey report would generally be available for each sleeve.

Pipeline characteristics:

- Pipeline installation date
- Operating pressure
- Pipeline wall thickness
- Pipeline diameter
- Pipe coating
- Depth of pipeline
- Piggable (Y/N).

Sleeve characteristics:

- Protection reason (i.e. road, rail, or water)
- Sleeve location (R or S or T)
- Sleeve class
- Sleeve installation date
- Sleeve length
- Sleeve diameter
- Sleeve thickness
- Sleeve material
- Sleeve end-seal
- Annular fill material.

Inspection and monitoring data:

- Date of last ILI
- CP status
- Status of Nitrogen fill in annulus.

These data could affect both the perceived likelihood of an escape and the consequences of the escape. The relative importance of these issues is outlined in the sections below.

5.4 Structure of the ranking scheme

The ranking scheme falls into two parts - firstly dealing with the likelihood of leakage from the pipeline and then secondly considering the consequences of the release.

A baseline 'leakage from pipeline' factor is derived, which is then modified by the effectiveness of the pipeline coating, the effectiveness of the cathodic protection system and the protection provided to the pipeline by the surrounding sleeve.

The consequences of the release are addressed in terms of the size of the release, the likelihood of ignition and the potential receptors in the vicinity.

These two components can be combined in two ways:

1. To produce a single numerical score
2. Classified into Low, Medium and High bands and then compared using a hazard matrix format.

At this stage, the components have been combined to give a simple numerical score.

5.5 Likelihood of leakage from the pipeline

Given that the key concern is leakage from the pipeline following external corrosion of the pipeline within the sleeve, issues regarding the protection given by the sleeve to the pipeline can be discounted. Alternatively this may be viewed as all sleeve types give essentially the same degree of protection from interference damage to the pipeline beneath and thus factors associated with interference damage would not differentiate between sleeves in the prioritisation scheme.

In this section a baseline pipeline leakage factor is derived, which is then modified by the effectiveness of the pipeline coating within the sleeve, effectiveness of the cathodic protection monitoring, and protection given to the pipeline by the sleeve.

5.5.1 Baseline pipeline leakage factor

It is considered that the baseline pipeline leakage factor could depend upon a number of factors including:

- Pipeline wall thickness
- Time spent buried
- Deterioration of the pipe whilst buried
- Fluids within the pipeline
- Operating pressure of the pipeline

These factors are considered further in the section below.

This factor is then modified in later sections for further considerations, for example records indicating a nitrogen environment has been maintained within the sleeve would significantly reduce the considered likelihood of a corrosion hole occurring)

EGIG data indicates that the likelihood of leakage broadly increases with the date of construction but does not indicate if this is also a function of time spent in the ground. Whilst it is noted that there may be differences in pipeline construction practices in the time period 1950 to 2000, it is considered that this would be less significant than the length of time spent buried.

It is also noted that for pipelines currently transporting natural gas, those present before the conversion to natural gas would have been transporting Towns gas. The effect of Towns gas on internal corrosion of the pipeline would be expected to be different to natural gas, but it is not clear how significant this effect would be. Transport of Towns gas in pipelines at pressures above 7 barg would have ceased in the UK by 1976.

Sleeves do not preclude ILI from monitoring the wall thickness of the pipeline wall inside the sleeve.

It is noted that un-piggable pipelines can be surveyed using remote techniques such as the Pearson survey (where damage to pipeline coatings may be detected by applying an AC current to the pipeline and then detecting a signal transmitted through the ground to a detector). However the sleeve surrounding the pipeline would make the signal difficult to analyse (particularly if the sleeve were metallic) and thus would not be a reliable way of detecting coating damage on the pipeline within the sleeve.

As a base relative ranking factor of the likelihood of the pipeline within the sleeve corroding, the pipeline wall thickness is related to the duration since the pipe was last inspected. This applies a differentiating factor between piggable pipelines that are regularly inspected with the wall thickness monitored (and corrosion detected) and the un-piggable pipelines where the pipeline inside the sleeve was last inspected at the time the sleeve was installed (which was likely to also be the time the pipeline was constructed). The relative likelihood of a pipe bursting is considered to be dependent upon the pressure within the pipeline, and thus the pipeline pressure is included in this parameter.

Age Factor

EGIG analysis (5th report) of pipeline aging for construction defect and corrosion failure modes indicated that pipelines constructed before 1964 were significantly more likely to fail than those constructed after 1964 but that there was not a marked deterioration in failure rate with age. However, it is not clear how the corrosion and construction defect components of these data would be de-convoluted.

Rather than using a generic failure frequency for the pipeline corrosion hole based upon UKOPA or EGIG data for failure frequency (in units of 100km yr), it was considered that better separation would be obtained by considering the parameter associated with the specific pipeline with in the sleeve. Consequently a simple model for the failure likelihood is obtained based upon the pipe wall thickness and time since the pipe wall was last inspected. Thus:

- Years since last ILI / Pipeline wall thickness:- for relative ranking of piggable pipeline leaking at sleeve location
- Years since sleeve installed /Pipeline wall thickness:- :for relative ranking for non-piggable pipeline leaking at sleeve location

Defaults

For missing data it would be assumed that:

- 20 years since last ILI for piggable pipelines
- Sleeve installed at same time as pipeline constructed
- If neither date of sleeve installation or pipeline construction is known, a 1950 default is assumed.
- Pipeline wall thickness of 7mm

Pipeline pressure factor: Estimate likelihood of corrosion leading to through wall gas escape is proportional to the operating pressure within the pipeline.

Baseline pipeline leakage factor = Age factor x Pipeline pressure factor

5.5.2 Coating type factor

The relative likelihood of a pipe leaking has been analysed for different coating types using EGIG data {as reported by De Stefani et al}. This has been used to estimate the relative protection given by the pipe coating WITHIN the sleeve. It is noted that some designs of sleeve seals result in a region of bare metal outer wall of the pipeline within the sleeve, thus an estimated relative failure frequency has been included for bare metal.

Table 7: Coating type factors

Criterion	Modification factor in BP paper (ii)	Pipeline coating relative ranking
Unknown (i) and other	3.86	4
Coal tar	0.91	1
Bitumen	1.47	1.5
Polyethylene	1.04	1
Epoxy	0.0016	0.002
Unknown if pipeline coated	~	25
Known bare metal on pipeline	~	50

Notes:

(i) it is assumed that this applies to an unknown coating type not whether or not the pipe is coated.

(ii) "A model to evaluate pipeline failure frequencies based on design and operating conditions", V De Stefani, Z Wattis and MR Acton.

For shuttered sleeve ends and/or concrete sleeves it can be assumed that the pipe coating inside the sleeve is the same as for the pipeline.

It is noted that the EGIG data above aggregates the failure frequencies across a number of different factors. De-convoluting these data may indicate other trends. In particular these data do not indicate if there is a correlation between coating type and; date of installation, pipeline wall thickness, length of time spent in the ground at the time of failure time, pipeline operating pressure or pipeline diameter.

5.5.3 Cathodic Protection Factor

Pipelines are protected from corrosion by factory and field applied coatings, and impressed current cathodic protection (CP) systems. These CP systems also provide protection to pipelines in sleeved sections, providing there are no interference currents present from sleeve anodes, or direct metallic shorts (often known as 'dead shorts') between the pipeline and sleeve. Where dead shorts are present, the pipeline within the sleeve can be rendered unprotected from the CP system, whilst in turn the sleeve becomes protected. Additionally, for CP current to flow effectively through the sleeve annulus a conductive fill is required, such as bentonite or cement grouts. These fills may also contain their own corrosion inhibitors, however it is difficult to ensure a complete fill of the annulus without voids. Furthermore, in the case of ‘curing’ fills, such as cement, cracking can occur during pipeline operation.

CP surveys, including direct current voltage gradient (DCVG) and close interval potential surveys (CIPS), may give an indication of a sleeve to pipeline metallic short, however these alone are not definitive.

In order to protect the pipeline within a steel sleeve where a short may be present, the annulus can be charged with nitrogen to provide an inert atmosphere within the sleeve. Where the sleeve is charged with nitrogen it is possible to monitor the pressure within the annulus to confirm the integrity of the sleeve and pipeline by identifying any leaks, and to confirm the presence of an inert environment within the sleeve.

Nitrogen filled sleeves can be cathodically protected to prevent loss of nitrogen through corrosion damage. It is recommended that CP of nitrogen filled sleeves be provided by the pipeline protection system by virtue of forged/welded end seals, or by the use of a direct cable bond between the sleeve and carrier pipe where non-welded end seals (e.g. epoxy end seals) are in place. It is further preferred that all metallic sleeves have CP test facilities installed.

Options used:

- Date of last inspection that confirmed cathodic protection system was operating ADEQUATELY at the sleeve location.
- Date of last inspection that confirmed cathodic protection system WAS NOT operating ADEQUATELY at the sleeve location.
- Cathodic protection regularly monitored since installation of the sleeve with protection working adequately throughout that period.

Table 8: Cathodic protection factors

Criterion	Working adequately throughout	Confirmed as working adequately within last 12 months	Found not to be working adequately within last 10 years	Unknown operation
Weighting	0.01	1	2	2

5.5.4 Entry of water and air into the sleeve

This section considers the factors that could result in water being present in the annulus between the pipeline and the sleeve.

It is considered likely that the entry of ground water and/or air into the annulus between sleeve and pipe would be at the ends of the sleeve and thus the likelihood of a leakage of water and air into the sleeve would NOT be proportional to length of sleeve. [Air and air could also enter an air filled annulus via a vent pipe connected to the sleeve]

From a survey undertaken on natural gas pipelines it was ascertained that there was limited information available on the design of the end seals used, and thus it is considered that this is not a parameter where data would not be readily available and thus it has not been used in the ranking score.

Although the likelihood of ground water being oxygenated can vary with soil type and depth of cover, it is considered that in most cases the soil type above the sleeve would not be known in detail and in most cases the pipeline would be buried to a similar depth (1 to 2 m deep). It is thus estimated that the likelihood of water and/or air affecting and/or entering a hole in the sleeve is not significantly dependent on the recorded burial depth of the sleeve.

If oxygenated water were entering the annulus, it could corrode the pipeline (and/or the sleeve) at one preferential location (for example at a low point on the pipeline or at location where the pipeline coating within the sleeve were damaged) or along the length of the sleeve. It is also noted that where corrosion is limited by the rate of ingress of oxygen and air, the greater the area that is being corroded the less would be the depth of corrosion. Thus, if corrosion were occurring at one location the depth of corrosion would be independent of the length of the sleeve, but if it were occurring along the length of the sleeve the depth of corrosion would be inversely proportional to the length of the sleeve. Consequently it would be estimated that the likelihood of a pipeline corroding within the sleeve is broadly independent of the length of the sleeve.

It is noted that the likelihood of the pipeline coating within the sleeve being damaged would be considered to be dependent on the method of construction and the actual construction quality control used onsite as well as the length of the sleeve itself. However, given it could take only one location where the steel pipeline below the coating was exposed or the coating was otherwise perforated in order to facilitate corrosion of the pipeline, it is considered that in most cases there would be one (or more) location within the sleeve that would be susceptible to corrosion. Again this would indicate that the likelihood of pipeline corrosion occurring within the sleeve is broadly independent of the length of the sleeve.

Overall the only process where it is envisaged that extensive corrosion of the pipeline within the sleeve could occur would involve the relatively free passage of water and air through the annulus. This essentially refers to an annulus that is open to air or not filled and there is no end sealing to restrict the flow of water and/or air through the annulus.

If there were essentially unlimited access of air to the annulus, a larger number of corrosion defects would increase the likelihood of through wall corrosion occurring. Consequently, it would be considered that the condition of the pipeline coating within the sleeve would be an issue.

As a conservative measure, the conditions for the scenario having the high likelihood of through wall corrosion (effectively unlimited air supply) have been used as the basis of the risk ranking. In this scenario, the likelihood of an escape of gas following through wall corrosion is related to the likelihood of damage to the coating, as outlined below.

5.5.5 Damage to pipeline coating factor

The likelihood of the pipeline within the sleeve corroding could also depend upon the likelihood of damage to the coating within the sleeve allowing passage of water and air to the metal beneath. Although such damage would be a site specific parameter, estimates could be made based upon the type of pipeline coating, age of coating, method of construction of sleeve and length of sleeve. It is considered unlikely that information related to the method of construction of the sleeve would be readily available. It is noted that the nature of the pipeline coating is already included as a parameter.

In general, it can it be assumed that the likelihood of coating damage to the pipeline within the sleeve would be proportional to the length of the pipe within the sleeve. However, welded /forged ends would also have a guaranteed area of bare pipeline metal within the sleeve at these locations.

Consequently a weighting factor has been added to allow for the likelihood of a bare metal area of pipe wall being present within the sleeve. For simplicity, it is simply assumed to be a function of the length of the sleeve.

It is assumed that the age of the coating is addressed by the consideration of the time since pipe installation for un-piggable pipelines and time since last ILI inspection for the piggable pipelines.

Pipeline coating damage factor = Sleeve length in m

If the sleeve length is unknown a default of 20m has been used.

5.5.6 Protection provided by the sleeve factor

The protection given by the sleeve could vary depending on a number of issues, as outlined below.

For the purposes of this ranking, it is assumed that the sleeve is buried and covered at both ends.

5.5.6.1 Date of sleeve construction

The date of sleeve construction has two major influences:

- Issues associated with construction techniques and quality control used at the time the pipe was constructed.
- Deterioration of sleeve associated with elapsed time spent in the ground.

The design and construction of the UK distribution pipeline system was carried out in accordance with IGE/TD/1. Between 1956 and 1970, TD1 suggested that sleeves of pre-cast concrete or steel should be considered for crossings, and filled with a suitable material or sealed and vented to atmosphere. From 1970 to 1984, TD1 recommended that steel sleeves should be used for all crossings with operating pressures above 350 lbf/in^2 (approx 24.1 barg), and also recommended the use of steel sleeves for additional protection where exemption of proximity limits was required.

Whilst the use of sleeves had been recommended since 1956, specific design recommendations were not available until the provisional release of sleeving guidelines in 1972 (and subsequent final issue in 1976), and until this point the specification of sleeves was a case for individual design. The release of the sleeving guidelines introduced design classes, and recommended the use of steel sleeves incorporating a nitrogen annular fill. Guidance was also provided with respect to the type of end seal to be used, whether rigid or flexible, based on the type of a fill material.

It is assumed that historical issues associated with sleeve construction are generally covered by the ranking given by the individual components.

5.5.6.2 Sleeve Class

This is a parameter that was devised for natural gas pipelines and outlined in IGE/TD/1 in 1972.

It is considered that the likelihood of the sleeve leaking would be generally inversely related to the onerous nature of the role of the sleeve, thus class 1 would be considered higher specification than class 2 which in turn would be considered a higher specification than class 3.

Sleeve class was introduced in circa 1976 and thus would be linked to date of sleeve installation. Potential options would be 1, 2, 3, N/A or unknown whereby N/A would be used for sleeves installed before 1976.

It is noted that in the UK many high pressure gas pipelines were constructed prior to the class scheme being published and thus the sleeve construction and usage may not align with one of the IGE/TD/1 class types. It may be possible to estimate an appropriate class type for sleeves constructed before 1972 based upon engineering records etc.

Class 3 was primarily used for concrete sleeves used to facilitate construction. These would have had a cementitious or similar fill (not nitrogen).

Overall it is considered that any variance associated with construction quality that could be linked to the usage class (or predating 1972) would be covered by other issues.

It is also noted that pipelines installed within construction class sleeves often had a supplementary coating applied on top of the normal pipeline coating. Thus, it could be considered that the pipes within the construction class sleeves may be better protected from external corrosion than the pipelines within other classes of sleeves.

Consequently the sleeve class is not used in the overall weighting scheme.

5.5.6.3 Sleeve age factor

The likelihood of a sleeve leaking is considered to be directly related to the age of the sleeve. For consistency with the pipelines, a typical thickness of a steel sleeve has been estimated (10mm). It is assume that the same rate of degradation would apply for other non-steel sleeves as well as degradation of the end seals.

Sleeve age factor = Age of sleeve/10

Default

- Sleeve installed at same time as pipeline constructed
- If neither date of sleeve installation or pipeline construction is known, assume 1950.

5.5.6.4 Sleeve material factor

Options: Steel, concrete, other or unknown

The design and construction of the UK gas distribution pipeline system was carried out in accordance with TD1. Between 1956 and 1970, TD1 suggested that sleeves of pre-cast concrete or steel should be considered for crossings, and filled with a suitable material or sealed and vented to atmosphere. From 1970 to 1984, TD1 recommended that steel sleeves should be used for all crossings with operating pressures above 350 lbf/in2 (approx 24.1 barg), and also recommended the use of steel sleeves for additional protection where exemption of proximity limits was required.

IGE/TD/1:1977 indicated that concrete should primarily have been used to facilitate pipeline construction equivalent to the Class 3. However, they were also listed as an alternative solution to steel sleeves for Class 2 protection requirements.

Due to the uncertainty surrounding the level of protection provided by CP systems to pipelines within steel sleeves, it could be considered that sleeves constructed from steel pose a greater risk to pipeline integrity than a concrete sleeve. It is noted that for a concrete sleeve the pipeline within should be coated and thus would primarily be susceptible to corrosion at locations where the coating had been damaged.

Overall, it is considered that a concrete sleeve would under normal operation have a limited ingress of water into the annulus, but the nitrogen filled steel sleeve would have no ingress of water into the annulus unless the sleeve were corroded and the nitrogen charge dissipated. With the steel sleeve there is however the possibility of the CP system causing corrosion of the pipeline within the sleeve.

Consequently the overall weighting scheme is:

Table 9: Sleeve material factors

Sleeve Material	Concrete	Steel	Other[1]	Unknown
Weighting	1	1.2	1.5	1.5

[1] Where "Other" can include "cast iron" and "metallic".

5.5.6.5 Sleeve end-seal factor

Given the level of data about the design of the end-seals, the sleeve material may be used to make inferences about the end seal of the sleeve, with steel sleeves typically being used for Class 1 or Class 2 duty having a rigid or flexible end seal that would be used in conjunction with a nitrogen fill whereas concrete sleeves would typically have a cementitious fill and a shuttered end seal (Although a range of end seals could have been used concrete sleeves including concrete blocks and wooden shuttering.) It is not known what would be a typical end-seal for cast iron sleeves or generic "metallic" sleeves.

It is considered that a flexible end-seal would degrade quicker and would be more susceptible to the entry of water than a rig end seal.

Consequently it is considered that a steel sleeve would be expected to have a more robust end-seal than a concrete sleeve and thus would provide more resistance to the entry of ground water to the annulus. However, the concrete sleeve would be expected to be filled with a cementitious mix that would restrict the ingress of ground water than an open annulus (such as would be the case for a formerly nitrogen filled annulus that had lost its pressurised charge of nitrogen).

Table 10: Sleeve end-seal factors

End-seal	Rigid	Flexible	Shuttering	Unknown
Weighting	1	2	3	3

5.5.6.6 Sleeve annular fill factor

Options: Cement/Grout, Nitrogen, Thixotropic, Air/No fill, Unknown

The cement/grout category includes all commercial variations of cements and pipeline grouts that were used as sleeve fillers, such as Poziment. The thixotropic materials used as sleeve fillers include bentonite, which was typically mixed with water at a concentration of 5-6% by weight.

Nitrogen would not be expected to be used as a fill material for a concrete sleeve.

It is estimated that "Cement/Grout", "Nitrogen" and "Thixotropic" materials give similar levels of protection whereas "Air/No fill" and "Unknown" give significantly lower levels of protection. Indeed an annulus that allowed the ready passage of ground water through it would be considered to be potentially more corrosive to the pipeline that a sleeve which is filled but filled with an unknown material. If it were assumed that an air filled sleeve were associated with a vent pipe it would be expected that there would be ready access of oxygen to the pipeline and possible entry of water through condensation of water within the incoming air.

It is also noted that an alkali environment, as may be promoted by a cementitious fill, would tend to passivate an exposed steel surface and reduce the likelihood of corrosion.

In some cases pulverised flue ash (PFA) has been used to fill the sleeve. This material can contain significant quantities of residual carbon, which in the presence of water can promote external corrosion

In the USA, a remedial practice where there is a concern about ongoing corrosion of the pipeline within the sleeve is to fill the annular space with a wax-like or gel-like material.

Table 11: Sleeve annular fill factors

Fill material	Cement/Grout	Nitrogen	Thixotropic	Air/No fill	PFA	Unknown
Weighting	0.8	1	1	10	10	3

However it is noted that the nitrogen filled steel sleeve scoring would be modified in view of the nitrogen monitoring programme.

5.5.6.7 Condition of the sleeve coating

It is noted that in the UK a steel sleeve would normally be wrapped or coated and that this coating may include a site wrapping over the end seal. It would be expected that a factory installed coating would be of better quality (unless damaged on site) than a coating applied on site.

However, in the USA the steel sleeve would normally be uncoated.

It is estimated that the external corrosion of a coated steel sleeve would principally occur at the ends of the sleeve where the sleeve was sealed onto the steel pipeline. Consequently the type of wrapping or coating of steel sleeve barrel itself would not be considered to be a significant factor but the nature of the coating of the end seal could be.

However, if the sleeve were not coated, it is possible that corrosion of a steel sleeve could occur anywhere along the length of sleeve.

It is noted that not all the records for the high pressure gas pipes does not identify whether, or not, the sleeve is coated and if so the nature of the coating. Sleeve coating is a parameter that should be available for those pipelines that are covered by the TD/1 survey reports.

However, as the type and condition of the sleeve coating are considered a secondary issue to the likelihood of water entering the annulus this parameter is not considered further.

5.5.6.8 Status of Nitrogen fill in annulus

Maintenance of nitrogen filled sleeves is undertaken using guidance that primarily focuses on monitoring nitrogen pressure within the sleeve annulus. The target pressure for nitrogen in the sleeve annulus is 1 barg. Any pressure reading above 1 barg may indicate a leak in the carrier pipe within the sleeve, whilst a reading below 1 barg indicates a leaking sleeve.

The capability of a nitrogen filled sleeve to retain its charge pressure is largely dependent upon the type and quality of its end seals, and the condition of its fill and vent connections.

Nitrogen fill factor:

- Month and year of last inspection that confirmed pressure of nitrogen WAS NOT being ADEQUATELY retained.
- Month and year of last inspection that confirmed pressure of nitrogen was being ADEQUATELY retained.
- Regularly (at least approximately annually) monitored since sleeve installed with no evidence of leakage of nitrogen from the annulus.

Table 12: Nitrogen fill factors

Criterion	No evidence of leakage	Not nitrogen filled	Over 1 year since last adequate monitor	Inadequate reading in last 10 years
Weighting	0.01	1	1.5	3

5.5.7 Summary of pipeline leakage factor

The pipeline leakage factor is given by:

Pipe age factor x Pipeline pressure x Coating type factor x CP factor x Coating damage factor x Sleeve protection factor

Where the Sleeve protection factor is given by:

Sleeve Age factor x Sleeve material factor x Sleeve end-seal factor x Sleeve annular fill factor x Nitrogen fill factor.

Note: The pipeline leakage factor scores can be divided into Low, Medium and High bands once a representative set of pipeline sleeves have been processed by the scheme.

5.6 Consequence of leakage

5.6.1 Size of potential hazard

Holes in pipelines are divided into three categories within the EGIG data, which indicates that ~97% of leakages are pinholes with ~2% as larger holes and 2% as ruptures. In this case, the EGIG definition of pinholes covers diameters up to 20mm.

High pressure gas pipelines are typically regularly surveyed, which although not primarily for potential leakage, could be used to identify discolouration of vegetation or other evidence of leakage. It is considered that an initial corrosion pinhole of a pipeline within the sleeve would be unlikely to lead to pipeline rupture in short timescales. [For completeness it is noted that it is considered that the initial escape at Ghislenghein in 2005 is considered to have developed into the full pipeline rupture in a matter of tens of minutes.] Consequently it would be expected that any leakage from a corrosion hole would be detected before the hole had significantly increased in size.

There could be some restriction to flow from the pipeline through a cementitious fill etc. but for most practical purposes the final orifice size from which the gas is escaping is considered to be of a pinhole magnitude.

It is noted that if there were an escape of gas from a pinhole in the pipe wall, it would be expected that the annular space would become filled with natural gas at above atmospheric pressure, thereby precluding the further entry of air into the annular space. It would also be expected that the passage of natural gas through the annular space would tend to remove any water present. Consequently, it would be expected that once gas started escaping through a pinhole there would not be any further corrosion of the pipe at this point.

Thus it is considered that all leakage from the pipeline would be of the pinhole magnitude and thus for purposes of the ranking scheme, all releases can be considered to be of an equivalent size.

The product PD^2 can be used as the relative ranking of the magnitude of the size of the gas cloud (i.e. potential hazard) that would be provided by the pipeline were there to be a rupture of the pipeline of diameter D and operating pressure P. However, it is considered that the potential hazard presented by a corrosion pinhole in the pipeline would be represented by just the pipeline operating pressure.

Thus the potential hazard of the ignited gas release has been related to the pipeline operating pressure.

5.6.2 Ignition likelihood

IGEM/TD/2 gives a relationship for ignition probability (P_{ign}) of pipeline punctures of:

$$P_{ign} = 0.0555 + 0.00685\ Pd^2 \text{ for } 0 \leq Pd^2 \leq 57$$

Where P is pipeline operating pressure (in bar) and d is the diameter of the release (in m). This correlation is also applied in the PIPESAFE pipeline risk assessment software. NB. In IGEM/TD/2 it does not make clear that for punctures, the hole diameter rather than pipeline diameter is used in this calculation

Applying this to pipelines operating at 7 and 70 barg and hole sizes of 6mm and 20mm diameter resulted in negligible differences in the calculated ignition probabilities, all being approximately 0.00555.

It is estimated that the size of the escape and thus the ignition likelihood would not vary significantly with type of sleeves, nature of annular fills etc and would all fall in the broadly pinhole range.

Thus, although it is considered that the likelihood of ignition is related to the volume of gas escaping and thus would also be directly related to the pipeline pressure, in this case it is considered that it is not a significant factor and that any effect would be essentially incorporated within the size of potential hazards factor and is thus not included here as a separate factor.

It is considered that the estimated ignition probability could be considered to be a function of the locality of the release. This can be identified in terms of the crossing type and/or pipeline environment.

Sleeves have been installed to protect pipelines at traffic crossings, including roads, railways, and water courses. Road crossings include the crossing of motorways, A and B roads, and minor roads and tracks. Water crossings include the crossing of rivers, streams, brooks, and canals. ‘Other’ refer to sleeves that were installed due to proximity reasons (including crossing of other pipelines), or sleeves with insufficient records and for which the crossing type is unknown.

It is noted that there is a slight ambiguity in that “other” covers known crossings of pipelines with other features (such as other pipelines) as well as cases where the nature of the crossing is not known. Working on the basis that geographical features such as railways, roads and rivers are discernible, it is assumed that those cases where it is not known what is being crossed are broadly equivalent to the “other” class of crossings.

Sleeves have also been used to ensure that any escape of gas from the pipeline within the sleeve is vented to atmosphere at some distance from the traffic crossing. These would reduce the likelihood of ignition by a passing vehicle.

It is considered that the likelihood of ignition could be slightly greater for road and railway crossing relative to river or other. However it is overall considered that there would not be any significant difference in the likelihood of ignition for the various potential releases being considered..

In order to provide some differentiation between different sleeve locations, a weighting is given in terms of crossing type and general location.

Table 13: Crossing type factors

Criterion	Road	Rail	River	Other
Weighting	1.5	1.5	1	1

Table 14: Location factors

Criterion	R	S	T
Weighting	0.5	1	4

5.6.3 Receptor factors

Receptors (people at risk from the potential hazard) could be determined in relation to the pipeline location (R, S or T Pipeline Area Type: Rural, Suburban or Town). It is considered that in most cases the ignited release associated with a pinhole leak on the pipeline would have a relatively small hazard range of the order of tens of metres rather than the hundreds of metres associated with a pipeline rupture. A hazard range of tens of meters would be expected to affect nearby buildings in an urban environment but not a suburban or rural environment. And given that it is considered that in most cases the pipeline would be in a class R or S environment an alternative differentiator may be the nature of the crossing.

5.6.3.1 Crossing receptor factor

Roads are typically described as high density, other or tracks and Rail crossings are typically considered as high density or other. It is considered possible that any escape could be ignited by the road or rail vehicle and in that case injuries and fatalities would primarily occur to the occupants of that vehicle. Given the number of people potentially at risk within a train is greater than those at risk within a typical road vehicle (car) a slightly higher rating could be applied to rail crossings compared to road. It is considered that few people would be close to river or other crossing types.

However, this consideration of different crossing types assumes that the location of any escape breaking through the ground surface is near to the crossing. For a pinhole escape on a pipeline within a sleeve it is considered that the location of the escape breaking through to the ground surface would be determined by the location of any holes in the surrounding sleeve, which would be most likely to occur at the end-seals. If the location of the escape breaking through the ground surface were determined by the position of the sleeve ends and the ends were suitably distant from the crossing, it is likely that the ignited release would have little effect on the occupants of a passing vehicle.

Sleeves have also been used to ensure that any escape of gas from the pipeline within the sleeve is vented to atmosphere at some distance from the traffic crossing. These would reduce the likelihood of fatalities or injuries within a passing vehicle.

Given the ends of the sleeves would normally be a “safe” distance from the road, rail etc, an equal receptor likelihood has been assumed for all crossing types.

5.6.3.2 General receptor factor

A high weighting is given for a pipeline inside an urban environment because there would be potentially many people present all of the time.

As noted above it would be expected that any gas escape would break through the ground surface near to the sleeve ends and thus the environment at the sleeve ends would be used in the assessment. However, it would not be expected that the environment at the sleeve ends would be significantly different to that generally associated with the pipeline at the sleeve location and thus a weighting is given in terms of the generic pipeline location.

Table 15: General receptor factors

Criterion	R	S	T
Weighting	1	4	10

5.6.4 Summary of Consequence factor

Consequence factor = Pipeline pressure x Ignition factors x Receptor factor

Note that the consequence factor scores could be divided into Low, Medium and High bands once a representative set of pipeline sleeves have been processed by the scoring scheme.

5.7 Combining the likelihood and consequence factors

The likelihood and consequence factors are calculated separately and have been combined by simple multiplication to produce an overall score for the sleeve.

However, the importance of inspecting a sleeve could also be assessed based upon the numerical score provided for leak likelihood or the score for the consequences associated with the sleeve location. Once a number of sleeves have been analysed it would be possible to put these scores into low, medium and high bands and produce an overall matrix.

6 Review

6.1 Parameters used in the Risk Ranking model

From the list of potential parameters a relative ranking scheme has been developed using the parameters highlighted in the list below.

Pipeline characteristics

- Pipeline installation date
- Operating pressure
- Pipeline wall thickness
- Pipeline diameter
- Pipe coating
- Depth of pipeline
- Piggable (Y/N)

Sleeve characteristics

- Protection reason (i.e. road, rail, or water)
- Sleeve location (R or S or T)
- Sleeve class
- Sleeve installation date
- Sleeve length
- Sleeve diameter
- Sleeve thickness
- Sleeve material
- Sleeve end-seal
- Annular fill material

Inspection and monitoring data

- Date of last in line inspection
- Cathodic protection status
- Status of nitrogen fill in annulus

It is considered that these pieces of information should be obtainable for most sleeves on most pipelines.

Using these parameters a ranking score can be calculated based upon the likelihood of the pipeline leaking and the potential consequences of such a leak.

It is important to note that this ranking score is an empirical number within a non-linear ranking scheme that has been designed to identify those sleeves most at risk of housing a leaking pipeline within a high consequence area.

6.2 Generic screening

The table below gives a general overview of the criteria for priority in inspecting the pipelines within sleeves. Alternatively, these could be combined to produce a matrix, as shown below for the high to low ranges.

However it would be expected that the risk ranking would be superseded by engineering judgement were any specific issues known about certain sleeves, for example if it were known that a sleeve contained standing water it would be expected that that such engineering knowledge would be used to prioritise the more detailed inspection.

Table 16: Table of key features

Priority	Sleeve Features	Pipeline features
Immediate	Uncoated pipeline within sleeve without continuous record of nitrogen filled annulus	Pigging or other inspection method indicates presence of coating defects and/or pipe wall corrosion.
High	Air filled annulus with vent pipes CP shorted between sleeve and pipeline T-location	Bitumen or coal tar coating High pressure Constructed before 1964 Not piggable
Medium	Concrete and steel sleeves with non gaseous fills (e.g. cement, thixotropic materials etc)	
Low	Nitrogen filled annulus with records of continuous acceptable performance	Low pressure Constructed after 1984 Recently pigged

Table 17: Matrix combining sleeve and pipeline features

	Pipeline features	Low pressure Constructed after 1984 Recently pigged	~	Bitumen or coal tar coating High pressure Constructed before 1964 Not piggable
Sleeve Features	**Priority**	Low	Medium	High
Air filled annulus with vent pipes T-location CP shorted between sleeve and pipeline	High	**Important**	**Very important**	**Critical**
Concrete and steel sleeves with non gaseous fills (e.g. cement, thixotropic materials etc)	Medium	**Low**	**Routine**	**Important**
Nitrogen filled annulus with records of continuous acceptable performance	Low	**NO immediate need to inspect**	**Low**	**Routine**

In the above matrix, an estimate is made of the importance to inspect the pipeline within the sleeve.

6.3 Application to other risk models

The engineering judgement analysis above has broadly divided sleeves into three categories, which generally relates to the likelihood of the pipeline within the sleeve failing through a corrosion hole. These bandings can then be broadly related to the generic failure frequency of the pipeline (such as those presented by EGIG, UKOPA or CONCAWE) in order to estimate a failure frequency of the pipeline within the sleeve

Based upon the engineering judgement analysis applied above, these three bands are considered further below and a failure frequency modifier estimated for the sleeve type.

Low risk

For the class of sleeves where there has been an history of a continuous nitrogen fill within the sleeve, it is considered that the likelihood of a corrosion hole occurring is very much less than the equivalent length of pipeline buried in soil. Theoretically, such a sleeve would prevent any corrosion occurring and thus a modifier of 0.01 could be applied.

Middle risk

There are a range of sleeve design types where it is not clear if the likelihood of pipeline corrosion within the sleeve is greater or less than the equivalent pipe buried in soil. These sleeves inhibit the access of water and oxygen to the pipe wall, but there is the increased likelihood of coating damage through the construction of the sleeve. In some cases the pipeline within the sleeve would have an additional pipe coating compared to that outside the sleeve. Overall it is not clear that the likelihood of corrosion would be worse than for the equivalent pipeline buried in soil and thus a modifier of 1 could be applied.

High Risk

Sleeve designs that provide ready access for air and water to the pipe wall (such as the air filled sleeve with vent pipes) could also have coating damage associated with the sleeve construction. Thus these sleeve types would be expected to have a significantly higher likely hood of pipe wall corrosion and thus a modifier of 10 could be applied.

The above modifiers are based upon engineering judgement. Such judgement could be tested by comparing the rate of identified corrosion defects within sleeved sections of pipes to unsleeved section pipes on piggable pipelines.

- It is considered possible that such an analysis of ILI data could show that for many of the sleeve types used in the UK the occurrence and size of corrosion defects in sleeved section was less than for the unsleeved sections.
- It is considered likely that the number and size of observed defects would be greater for the sleeves constructed to the generic USA design of air filled annulus with vents.

7 Conclusion

Historical incident data and engineering construction data have been used to propose criteria that can be used to estimate the importance on inspecting the condition of pipelines within sleeves on piggable and un-piggable pipelines. These features have been given a weighting based upon historical data and engineering judgement in order to provide a numerical scheme to rank the importance of inspecting the pipeline within a sleeve. Because much of the analysis is based upon generic data, it is expected that, on occasion, this ranking scheme would be superseded by site specific engineering judgement. For example, if it were known that a sleeve was intermittently filled with water, this could be important to inspect.

The engineering judgement within this model could be tested further by analysing in-line inspection data (from piggable pipelines) for the size and occurrence of corrosion defects observed within sleeved sections of pipeline relative to the unsleeved sections of pipeline. It is recommended that UKOPA considers performing this type of analysis.

Appendix A Notes on incidents on sleeved pipelines

This appendix reviews incidents that have occurred at pipeline locations within sleeves. These incidents are exclusively in the USA; to date no records have been found of incidents within sleeves on pipelines elsewhere in the world and the current UK experience is that there has not been any incident on a pipeline within a sleeve.

A.1.1 Colonial pipelines 1980

Colonial Pipeline Company Petroleum products pipeline failures Manassas and Locust Grove Virginia, March 6, 1980 NTSB-PAR-81-2

On 6 March 1980 a pressure surge on a Colonial Pipelines Company pipeline resulted in two ruptures of a 32” diameter pipe carrying petroleum products (kerosene or fuel oil depending upon location). The NTSB investigated the two ruptures and produced the investigation report PAR-81-2. The comments made below are based upon the information in this report.

Both ruptures were caused by pre-existing defects in the pipeline one being a crack caused during transport of the pipe sections and the other corrosion of the pipeline wall at a location within a sleeve.

The rupture within the sleeve occurred within a 40” diameter sleeve that ran under State Route 234 (SR 234) near Manassas. The initial sleeve had been extended to accommodate the construction of a second lane to SR 234 (at an unstated date).

Table 18: Colonial pipeline parameters

Date laid	Diameter	Operating pressure	Grade steel	Wall thickness
1963	32”	~700psig	API 5L X52	0.281”

Metallurgical examination indicated that the Manassas failure occurred at an area near to the bottom of the pipeline that had been thinned by corrosion. The corrosion was considered to have been caused by ground water leakage through the end seal of the sleeve and entering the annular space between the pipeline and sleeve. The metallurgist considered that the sleeve would have prevented the pipeline having adequate cathodic protection at that location.

The report notes that the pipe coating was damaged within the sleeve and ascribes the damage to the sleeve construction process.

The report notes that electrical shorting of the pipe and sleeve can occur when the pipeline coating is damaged and the positioning spacers are damaged resulting in a metal to metal contact between the pipe and sleeve. Cathodic protection cannot adequately protect the pipeline in the presence of such a short circuit. Introduction of water into the annulus results in an electrolytic cell being established and corrosion occurring.

Statistical analysis of external corrosion anomaly data of cased pipe segments Prepared for The INGAA Foundation, Inc. by Southwest Research Institute, F-2007-10, December 2007

This report includes the following comment on this incident

- This OPS report regarded the metallic short as a minor factor to the incident, while the shielding effect was treated as the major cause. In fact, it is likely that the shielding effect resulted mainly from the short as discussed in Section 3.3 of this report and thus, short can likely be a key factor resulting in the incident. Recent experimental tests showed the sufficient CP can be achieved on the carrier pipe if the casing-pipe annulus is filled with electrolyte and the casing and pipe isolated. Direct metallic short could remove the CP benefit and allow free corrosion to occur.

A.1.2 Beaumont, Kentucky 27 April 1985

Texas Eastern Gas Pipeline Company ruptures and fires at Beaumont Kentucky on April 27, 1985 and Lancaster Kentucky on February 21, 1986, NTSB-PAR-87-01

A Texas Eastern Gas pipeline #10 ruptured at a location 2 miles east of Beaumont on 27 April 1985. A second rupture occurred on the parallel pipeline #15 in February 1986. The NTSB investigated the two ruptures and produced the investigation report PAR-87-01. The comments made below are based upon the information in this report.

The location of the 1985 rupture on pipeline #10 was on the southern side of a sleeve crossing than ran beneath State Highway 90. Running alongside pipeline #10 at this location were pipeline #15 and pipeline #25.

Table 19: Beaumont pipeline parameters

Pipeline	Pipeline #10	Pipeline #15	Pipeline #25
Date laid	1952	1957	1967
Diameter	30"	30"	36"
Operating pressure	~1000psig		
Grade steel	API 5L X52	API 5L X52	API 5L X52
Wall thickness	0.375"	0.375"	0.390"

The three pipelines ran approximately south to north being pressurised by the Tompkinsville Compressor Station. The distance of the rupture from the Tompkinsville Compressor Station was not stated in the NTSB report. Danville Compressor Station was located 75miles downstream of Tompkinsville and Owingsville Compressor Station was located 75 miles downstream of Danville.

The nature of the specific sleeve is not described but the report does give a generic comment on sleeve construction. The report indicates that a sleeve generally comprised a section of steel pipe two sizes larger than the pipeline. The pipeline was electrically insulated from the sleeve by using non-conductive spacers between the sleeve and pipeline at intervals along the sleeve. The annulus between sleeve and pipeline was generally sealed with a gasket to keep out water and dirt. Atmospheric vents were installed at each end of the casing. The descriptions in the report of the sleeves at this location would be consistent with this generic description.

The nature of the coating to pipeline #10 is not given in the report not is any direct comment made on the condition of the coating along the pipeline or within the sleeve. However, the report does comment that high temperatures found in pipelines up to 10 miles downstream of compressor station could cause earlier pipe coatings to disband.

In 1953 concerns were raised regarding the cathodic protection of Pipeline #10. From 1960 to 1970 readings indicated that pipe was electrically short circuited to the sleeve. In 1954, 1956, and 1964 work was undertaken to replace the sleeve end-seals and mud and debris were removed from annulus between the pipeline and sleeve.

OPS guidance indicates that where a casing is shorted to the pipeline and it is not practicable to eliminate the short, an operator may choose to monitor gas concentrations and once gas is detected take the appropriate corrective actions. The NTSB report does not indicate if gas monitoring were being undertaken.

In line inspection was introduced in 1967 by Texas Eastern. The report indicates that pipeline #10 was not inspected in the period up to 1985. The report does not indicate if pipeline #15 were surveyed in the period 1967 to 1985 and if so what where the findings.

In September 1983 work was undertaken to extend the sleeves to pipeline #15 and #25 (at a location to the north of Highway 90). This work did not uncover pipeline #10. The coatings to pipelines #15 and #25 were considered to be in good condition.

Following the construction work all three pipelines were buried to a depth of 6' (1.8m).

The pipeline had been operating at ~1000 psig for more than a year at the time of the rupture.

The pipeline ruptured on 27 April 1985 at a location downstream of Tompkinsville compressor station. The NTSB report does not directly indicate how far downstream, but notes that the affected section was isolated by valves at Tompkinsville and 18 miles downstream of Tompkinsville. [Figure 2 of the NTSB report implies that the failure location was approximately 9 miles downstream of the compressor station.]

The five fatalities were found within their house at the north wall of their house, which was located to the north of the pipeline. They had died from smoke inhalation with post mortem incineration.

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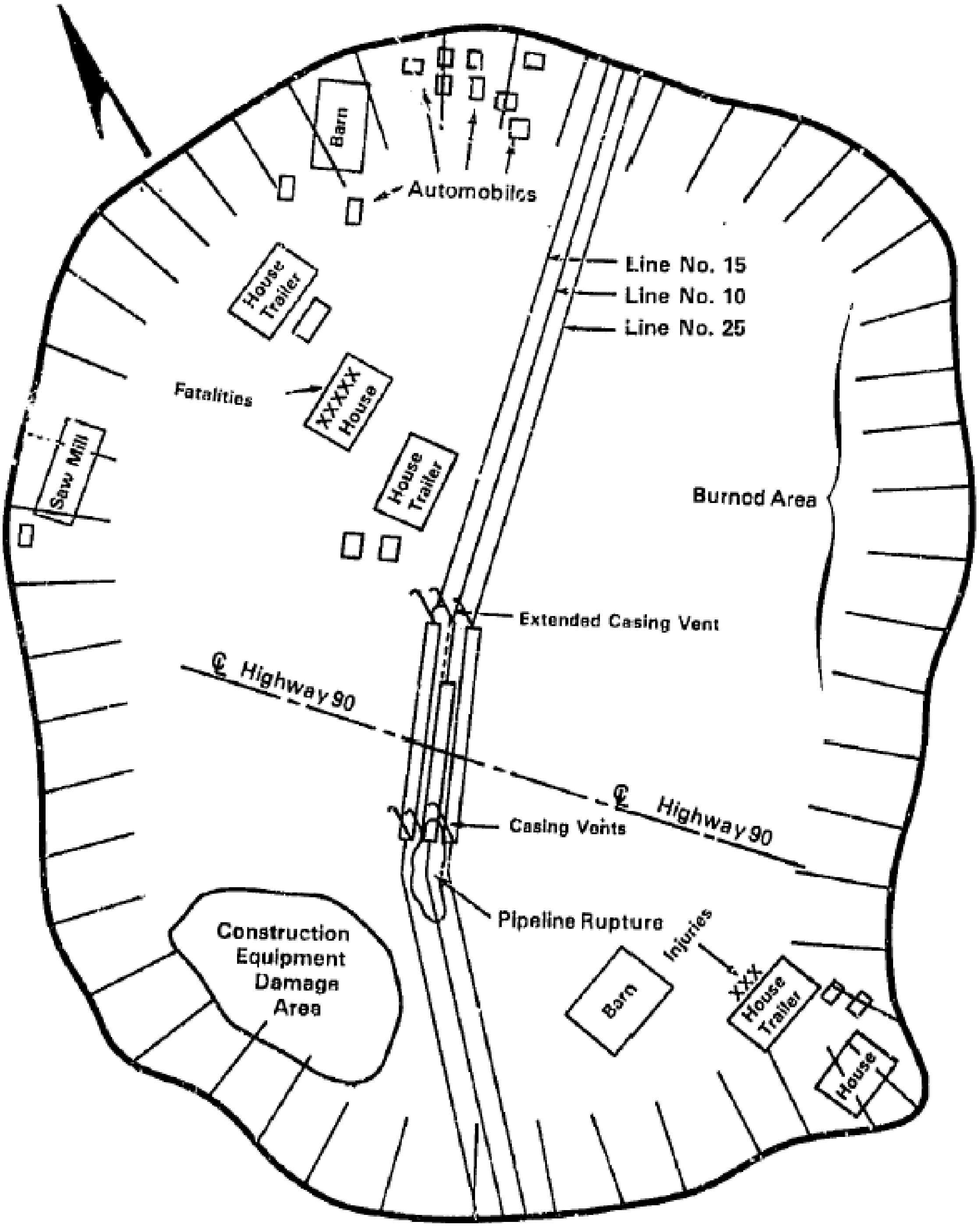

Figure 3.--Diagram of the accident site at Kentucky State highway 90.

Figure 10: Sketch of incident site from NTSB-PAR-87-01

Metallurgical examination found extensive areas of corrosion on the outside of the pipeline within the casing. The rupture had initiated at an area of corrosion at the top of the pipeline that was located ~17' inside the sleeve. The minimum remaining wall thickness found was 0.130".

The metallurgist indicated that the corrosion was caused by atmospheric corrosion caused by cyclic condensation and evaporation of water on the pipeline. The metallurgist suggested that the water may have entered the annulus via condensation within the vent pipes.

The metallurgical report indicated that there was a small flow of current from the pipeline to the sleeve at this location but that it was not considered a significant contributor to the corrosion at this location. The metallurgist also noted that this current flow would be consistent with mud or water providing a route between the pipeline and the casing but not with a direct electrical contact.

Following the rupture at Beaumont an in-line inspection was undertaken of pipeline #10 (and #15 and #25). This inspection found several locations where undetected corrosion had occurred. The report is contradictory between figure 2 and the text as to the location of where 35 pipeline replacements were made. The text indicates 25 pipeline replacements were made on the 75mile section of #10 between Tompkinsonville and Danvers (Pipeline #15 according to Figure 2 of the NTSB report) and a further 3 on the section between Danvers and Owingville (Pipeline #15 according to Figure 2 of the NTSB report). A further 7 replacements were made on Pipeline #15 between Tompkinsville and Danvers (Pipeline #10 according to Figure 2 of the NTSB report).

Following this in-line inspection, in September 1985 an area of corrosion on pipeline #15 just south of the casing near State Highway 52 was excavated and inspected. Because the corrosion was not bright and shiny the inspectors considered that the corrosions process was no longer active. Corrosion was located at a number of locations along the bottom of the pipeline. The pipe could not be completely inspected at this location because it was sitting on a rock ledge.

On 27th February 1986 pipeline #15 ruptured at this location just south of the sleeve.

Statistical analysis of external corrosion anomaly data of cased pipe segments Prepared for The INGAA Foundation, Inc. by Southwest Research Institute, F-2007-10, December 2007

This report includes the following comment on this incident

- This casing was located about 2 miles downstream of a compressor station with the line temperatures in the range of 140 - 160 °F. With high heat, the coating was badly damaged. With the presence of vents and the consistently higher line temperatures than the local temperature, cyclic water condensation occurred on the carrier pipe, which provided electrolyte necessary for the atmospheric corrosion.

The source of this information is not directly stated (although the NTSB report was referenced in the previous paragraph) and thus it may have originated in the 1988 OPS report, specifically OPS, Technical Division, Interoffice Report-Project No. 87-6, May 10 (1988). As noted above, this information is not included in the NTSB report.

Note:

According to Google earth Tompkinsville is about 11 miles south of the KY-90 near Beaumont. However, east of Beaumont the LY-90 runs in south –easterly direction. At a location about 2 miles along KY-90 south–east of Beaumont the highway is intersected by what appears to be a pipeline easement. About 2 miles south-west of the crossing point of this apparent easement and KY-90 there is a pipeline installation on Pipeline Road that appears to be a compressor station. Thus it would be likely that the affected casing were only approximately 2 miles away from Tompkinsville Compressor Station (although this location is approximately 9 miles from Tompkinsville itself).

A.1.3 North Blenheim New York 13 March 1990

Liquid propane pipeline rupture and fire Texas Eastern Products Pipeline Company, North Blenheim, New York March 13, 1990, NTSB-PAR-91-01

The Texas Eastern Products Pipeline Company (TEPPCO) 8” diameter pipeline (Line P-41) ruptured within a pipeline sleeve located beneath County Road 43 (CR43), near to North Blenheim village. The vaporised propane vapour flowed downhill along CR43 before it entered North Blenheim, where it ignited, flashing back to the pipeline rupture.

Pipeline line P-41 was a 165 mile long 8” diameter pipe transporting LPG that was constructed and hydrostatically tested to 1964.

Most (91%) of the pipeline was constructed with API 5LX pipes (wall thickness 0.203”) and the remaining 9% was made from API 5l Grade B (wall thickness 0.375”). Grade B was generally used where pipeline pressures were at their greatest, at lower elevations or crossings under roads and railroads. The pipeline was coated with a tape wrap with an overlay of felt.

At the rupture location the pipeline had a 8.625” OD and a 0.375” wall thickness.

The pipeline was the only utility at this location and had been installed by boring under the road for the sleeve. The sleeve was a 51.8foot long of 12.75” OD and 0.250” wall thickness that had been coated with a mastic material.

In 1985 an internal inspection of the pipeline was made and any corrosion pits deeper than 0.1” or located inside sleeves were investigated. Based upon the investigation results sections of pipeline were replaced; this replacement being completed in 1986.

In 1987 and 1988 CP surveys indicated sleeve was shorted to pipeline at County Road 43 (CR43). Maintenance work to remove a short between the sleeve and pipeline beneath CR43 began 20th February 1990.

After exposing the western end of the sleeve and removing the boot-type seal it was found that the annulus was full of water, a plastic sleeve insulating spacer was broken within 6” of the end of the sleeve and the bottom of the pipe was touching the sleeve. The pipe coating was recorded as being in good condition and there was no evidence of corrosion pitting.

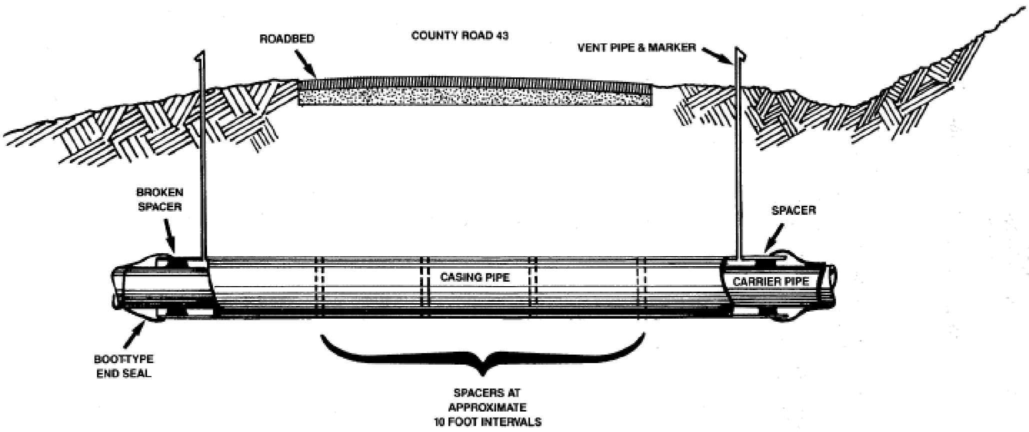

Figure 11: Sleeve beneath County Road 43

Following remedial work it was found that there was still a short between the sleeve and pipeline. Consequently it was planned to excavate the eastern end of the sleeve. In this period the pipeline was supported within the open western excavation.

The pipeline ruptured on 13 March 1990 with the resulting explosion and fire killing two people.

Following the incident, the eastern end was excavated revealing that the pipe was centred within the sleeve, the sleeve insulator was near the end of the sleeve and the synthetic rubber end cap (not damaged by the fire) was 2' to 3' from the sleeve whilst the stainless steel straps appeared not to have been sufficiently tightened to hold the seal in place.

At the western end the damage was consistent with the rupture and fire. Where the pipe exited the sleeve the two were in contact. The link seal (used to seal the sleeve) installed in February was found about 1m from the sleeve.

A 2" diameter vent pipe was installed at both ends of the sleeve, which extended to above ground level. A plugged 2" diameter drain pipe was connected to the bottom of the western end of the sleeve (this was reportedly broken during the post-incident excavation).

A circumferential pipe fracture was found 2' inside the western end of the casing at a point 2" east of a pipe girth weld. The two fracture faces had separated by ~18mm.

It was found that the pipe was supported by five sets of spacers inside the sleeve, whereas the manufacture would have recommended eight sets.

Metallurgical examination found that the pipe had failed in an area that had been weakened by small shallow stress corrosion cracks (SCC) that were orientated circumferentially (indicative of a high bending stress). The high bending stress in combination with water could have caused or accelerated the cracking process. It was not determined if the SCC were present before the maintenance work, in which case the maintenance work would have contributed to the final stress on the pipe or if SCC were generated by the maintenance work

The steel in the pipe had a high brittle to ductile transition temperature, which made it susceptible to brittle fracture at the normal operating temperatures of the pipe.

A.1.4 Delhi, Louisiana 2007

External corrosion — Conclusion: Cased pipe segments could be less safe than uncased segments, Oil and Gas Journal. 20/4/2009

This report is a cut and paste of the SWRI statistical analysis report but includes reference to a further incident.

- A more recent incident took place on a Columbia Gulf Transmission Co. gas line Dec. 14, 2007, near Delhi, La. A natural gas release, explosion, and fire killed one person and injured another in the same vehicle as they travelled on the highway where the pipe crosses in a casing.
- Investigators do not know the exact cause of the failure, but a preliminary visual examination suggested external corrosion to be the cause. Investigators suspect corrosion inside the casing caused the explosion, but are not certain whether the failure actually initiated inside or outside the casing.

Press report

A press report on this incident indicated that:

- The 30-inch underground pipe, installed in 1954, ruptured near a small bridge that crosses a bayou on Interstate 20 at the Richland-Madison Parish line. A second pipeline near the site was installed in the 1960s, and a third in the early '70s. All were made of steel.
- The other two lines, which were shut off after the blast as a precaution, were not damaged. Gas flow was restored to one Friday evening and the second was expected to be back in service on Saturday night.

Letter from Columbia Gulf Transmission (CGT) to OPS (dated 24 March 2009)

Victor Gaglio Senior Vice President Operations to RM Seeley, Regional director Office of Pipeline Safety, Pipeline and hazardous materials Safety Administration.

The key points in this letter were:

- The 14 December 2007 incident occurred where line #100 crossed Interstate – 20 (I20) to the south of the highway.
- Line 100 was laid in 1954.
- Independent metallurgical examination by Metallurgical and Materials Technologies Inc. MM&T indicated that the pipeline had corroded within the sleeve and that the corrosion was caused by moisture in the atmosphere as well as standing water within the sleeve. The analysis also identified damage to the pipeline coating and high chloride concentrations as contributors to the corrosion. MM&T indicated that there was no evidence that the pitting corrosion had penetrated the pipe (thereby resulting in an escape of gas) prior to the rupture
- CGT had been undertaking high resolution internal inspections as well as instrumented leak detection surveys for all sleeved pipe. A standard resolution in-line inspection was undertaken at this location in October 1996. This inspection found 63 areas of corrosion in the runs from Delhi La to Mississippi River and thence to Inverness MS. None of these areas of corrosion were considered sufficient to warrant remedial work at this time.

- Before 2006, CGT monitored sleeve vents of all casings with instruments for evidence of leakage. After 2006, in conjunction with improved ILI, this was changed to inspection of all sleeves where there was an electrical short.
- CGT indicated that the survey of the CP system undertaken 27 June 2007 had found that the CP system were shorted and that this casing was to be added to the list of sleeves that were regularly monitored. The letter is not clear if there had been previous inspection of the CP and if so that the CP was found to be operating adequately during these earlier inspections.

The letter also indicated that CGT had previous similar incident on their pipelines and produced a summary table of incidents from 2000. The key points of this table and information in the letter text is included in the table below.

Table 20: Columbia incidents

Date	Location	Pipeline	Environment	Failure description	Cause
29/9/2000	Delhi LA - just north of I20	#200	In field	Failure	External corrosion – possibly microbiologically induced corrosion (MIC)
3/8/2001	Rayne, St Landry Parish, LA	#100	In sleeve	Leak – discovered during leakage survey	External corrosion –located beneath pipeline spacer – likely to be through coating damage
13/9/2006	Delhi LA – US Route 80	#100	In sleeve	Leak	External corrosion – likely caused by failure of pipeline coating
14/12/2007	Delhi just south of I20	#100	In sleeve	Failure	External corrosion

The letter also noted that in some cases rectification work included filling the annulus between the pipeline and the sleeve with inert material.

A.1.5 Romeoville, Illinois 14 May 2011

An 8 inch diameter NGL pipeline failed in Romeoville, Illinois on 14 May 2011 resulting in a leak of liquid butane. Corrosion inside a sleeve under a road was the cause of the failure. Corrosion 2.5 feet from the failure had been seen by in-line inspection in 2007, but was not within action limits at the time.

Letter 15 June 2011 from David Barrett, Director, Central Region PHMSA – Office of Pipeline Safety to Mr. Wes Christensen, Senior Vice President of Operations, ONEOK NGL Pipeline, LP, 100 West Fifth Street, Tulsa, Oklahoma

On May 14, 2011, at approximately 3:40 p.m. CDT, a failure occurred on ONEOK's hazardous liquid pipeline 106W near the intersection of West 135th Street and North Weber Road in Romeoville, Illinois. The failure occurred within a cased crossing under West 135th Street. Initial reports by ONEOK indicated that approximately 100 barrels of refinery grade butane were released.

The released butane pushed dielectric material from the annulus of the sleeve and out the sleeve vent at West 135th Street.

As reported by ONEOK the 106W pipeline was generally constructed of 8-inch diameter pipe having a multiple wall thickness ranging from 0.188 to 0.322-inch with the predominate wall thickness being 0.188-inch, Grade API 5L X-52 pipe of unknown manufacture. ONEOK reported the pipe seam was high frequency electric resistance welded (ERW) and was constructed in 1967 but could not produce documentation confirming the manufacturer. The failed pipeline at West 135th Street was 8-inch diameter, 0.250 inch wall thickness. Per the alignment sheets and observations by PHMSA and ONEOK onsite, it was apparent that the West 135th Street crossing had been modified since the time of original construction.

The maximum operating pressure (MOP) of the 106W pipeline was 1440 psig. The discharge pressure at Lemont Pump Station was approximately 1148 psig at the time of the failure.

The failure occurred inside a 12-inch steel sleeve. PHMSA investigators and ONEOK visually examined the failed pipe and sleeve at the scene, and observed a failure that was indicative of external corrosion of the carrier pipe at the 12 o'clock position underneath a spacer used to maintain clearance between the pipeline and the sleeve. The failed pipe was transported to Kiefner and Associates near Columbus, Ohio for further metallurgical examination.

The previous operator of the 106W pipeline performed an inline inspection (ILI) of the pipeline in 2007 with high resolution magnetic flux leakage (ML) and calliper tools. A 37% deep metal loss anomaly was reported approximately 2.5 feet downstream of the failure. Review of the raw ILI data by ONEOK after the 14th May failure showed an indication of a feature at the point of failure under the spacer in the sleeve. ONEOK has indicated that at the time of the 2007 ILI, none of the features reported at the 135th Street crossing were actionable.

A.1.6 Incident reviews

a) Statistical analysis of external corrosion anomaly data of cased pipe segments Prepared for The INGAA Foundation, Inc. by Southwest Research Institute, F-2007-10, December 2007

This SWRI report included a review of historical incidents on sleeved pipe segments. This review of reportable pipeline incidents of cased pipe segments between August 7, 1984 and November 8, 2006 in the OPS database showed that among the 11 incidents identified, 5 were identified as being caused by corrosion, 3 by excavation, and 3 by unknown causes.

Of the 5 corrosion incidents, 3 were identified as resulting from atmospheric corrosion. Thus, it was concluded that atmospheric corrosion should be carefully considered when cased pipe segments are determined and/or prioritized for examination.

Table 4.1 of this report presents the data on pipeline incidents in casings for the period 1984 to 2006. The key data on the spontaneous failures (i.e. excluding unknown and interference damage) are outlined below.

Table 21: SWRI Review of incidents

Incident date	State	Company	Type	Type	Pipeline construction year	Pipe diameter (inches)	Cause
27/4/1985	Kentucky	Texas Eastern Pipeline Company	Rupture	Transmission system	1952	30	Corrosion – atmospheric inside casing
16/8/1988	Texas	Amoco Gas Company	Leak	Transmission system	1961	12	Corrosion – localised external pitting – galvanic
18/3/1992	Nebraska	Natural Gas Pipeline Company of America	Leak	Transmission system	1942	26	Corrosion – localised external pitting – atmosphere
1/9/2006	Louisiana	Columbia Gulf Transmission	Leak	Interstate	1954	30	Corrosion – atmospheric inside casing
16/10/2006	Kansas	Southern Star Central Gas Pipeline	Leak	Interstate	1971	20	Corrosion – disbanded coating in areas shielded by casing

Note: All pipes were classified as “onshore” and “coated”.

b) PHMSA spreadsheets

A number of database spreadsheets were found on the PHMSA website, principally the database of flagged (significant) incidents given on http://primis.phmsa.dot.gov/comm/reports/safety/SIDA.html?nocache=3640. These spreadsheets were interrogated for incidents involving casings and cased pipelines. This section identifies the key features of incidents involving pipeline casings as pertaining to pipelines used for gas transmission and for hazardous liquids.

PHMSA data for leakage from gas transmission pipes examined for

- Onshore pipes
- Incidents associated with sleeved (cased) pipelines.

Records in three formats

- 1986 to 2001
- 2002 to 2010
- 2010 onwards

Table 22: PHSMA – Incidents in casings 2011 for gas transmission pipes

Operator	Incident	Location	Leak size	Pipeline name	Nominal diameter (inch)	Wall thickness (inch)	Coating	Pipe spec	Date laid	Incident pressure (psig)	MOP (psig)	Cause
Buckeye Development & Logistics LLC	Houston, Texas 12/13/2011	Cased road crossing – under pavement	Pinhole leak – not ignited	Webster Natural Gas	10	0.279	Coal tar	X-42	1957	533	860	External corrosion – not pipeline operations. Localised pitting – galvanic corrosion - Cathodic protection installed 1957 – annual inspections – evidence that shielded. Evidence of prior damage.
Pacific Gas & Electric Co	Novato, California 9/19/2011	Cased road crossing – under pavement	Leak – not ignited	L-21G	16	0.281	Coal tar	X42	1961	341	450	Unknown cause- No operational issues identified – Small leak on pipeline identified by mark and locate employee.
Tennessee Gas Pipeline Co (El Paso)	Hanoverton, Ohio 02/10/2011	Cased road crossing – under soil	Circumferential rupture - ignited	LINE 200-4	36	0.344	Coal tar	API 5L OR Equivalent	1963	733	790	Material failure of pipe or weld - Construction, installation or fabrication related – no abnormal pressure excursions.

Table 23: PHSMA – Incidents in casings 2002 to 2010 for gas transmission pipes

Operator	Date	Location	Leak type	Incident pressure (psig)	MAOP (psig)	Date laid	Nominal pipe diameter (inch)	Wall thickness (inch)	SPEC	Cause
COLUMBIA GULF TRANSMISSION CO	14/12/2007	DELHI, Louisiana	Rupture	930	935	1954	30	0.38		Corrosion External - Atmospheric
SOUTHERN STAR CENTRAL GAS PIPELINE INC.	16/10/2006	WICHITA, Kansas	Pinhole leak	172	180	1971	20	0.26	API5L	Corrosion External – Disbonded coating in area shielded by casing
COLUMBIA GULF TRANSMISSION	23/9/2006	DELHI, Louisiana	Pinhole leak	863	935	1954	30	0.5		Corrosion External – atmospheric inside of casing
EL PASO FIELD SERVICES	23/4/2003	WICKETT, Texas	Road casing vent leaking	892	1025	1971	12	0.22	API5L	MISCELLANEOUS
WILLIAMS GAS PIPELINE - TRANSCO	16/10/2009	PLAINS, Pennsylvania	Pinhole leak	960	2400	1958	23.38	0.38	API-5L	Corrosion External -
CENTERPOINT ENERGY GAS TRANSMISSION	12/06/2008	PINE BLUFF, Arkansas	OTHER – Pinhole leak caused by torch burn	259	400	1957	16	0.25	B	INCORRECT OPERATION

Table 24: PHSMA – Incidents in casings 1986 to 2001 for gas transmission pipes

Operator	Location	Incident type	Date	Cause	Date laid	Nominal pipe diameter (inch)	Wall thickness (inch)	Pipe spec	Location	Incident pressure (psig)	Max pressure (PSIG)
NATURAL GAS PIPELINE CO OF AMERICA	OTOE, Nebraska	LEAK - BODY OF PIPE	18/3/1992	CORROSION – atmospheric	1942	26	0.25	5LX	Cased railroad crossing	550	712
AMOCO GAS CO	PASADENA, Texas	LEAK - BODY OF PIPE	16/81988	CORROSION – Galvanic	1961	12	0.22	API 5L	Casing	500	700

Table 25: PHSMA – Incidents in casings 2010 onwards for hazardous liquids pipes

Operator	Location/ Date	Fluid	Release size	Pipe name	Location	Nominal diameter (inch)	Wall thickness (inch)	Pipe spec	Year laid	Cause	Incident pressure (psig)	MOP (psig)
SHELL PIPELINE CO., L.P.	MILWAUKEE, Wisconsin 31/1/2012	Refined and/or petroleum products (non-HVL) which is a liquid at ambient conditions	LEAK – pinhole	Mitchell Field 10"	Road crossing - UNDER PAVEMENT	10.75	0.25	5L - coal tar coat	1972	EXTERNAL CORROSION – localised pitting	50	150
ONEOK NGL PIPELINE LP	LEMONT, Illinois 08/08/2011	HVL*	OTHER	ONEOK NORTH SYSTEM PIPELINE	Road crossing - UNDER SOIL	8.625	0.25	5L - coal tar coat	1967	ELECTRICAL ARCING FROM OTHER EQUIPMENT OR FACILITY –	836	1440
ENTERPRISE PRODUCTS OPERATING LLC	TAFT, Texas 16/6/2011	HVL*	LEAK	L27A-10	Rail road crossing - OTHER	10	0.25	API-5L - coal tar coat	1966	EXTERNAL CORROSION – localised pitting - CP installed 1966	190	672
ONEOK NGL PIPELINE LP	ROMEOVILLE, Illinois 14/5/2011	HVL*	Leak – pinhole	ONEOK North System 106W Pipeline	Road crossing - UNDER PAVEMENT	8.625	0.25	SMAW – Cold Applied Tape coat	1967	EXTERNAL CORROSION localised pitting - CP installed 1968	1141	1440
ENTERPRISE PRODUCTS OPERATING LLC	WYOMING, Iowa 16/9/2010	HVL*	Leak - pinhole	EAST LEG BLUE LINE	Road crossing - UNDER PAVEMENT	6.625	0.188	API 5L - coal tar coat	1960	MISCELLANEOUS	639	1880

Operator	Location/ Date	Fluid	Release size	Pipe name	Location	Nominal diameter (inch)	Wall thickness (inch)	Pipe spec	Year laid	Cause	Incident pressure (psig)	MOP (psig)
ENBRIDGE ENERGY, LIMITED PARTNERSHIP	DYER, Indiana 17/2/2012	CRUDE OIL	Other	LINE 6A MP 461	Railroad crossing – Exposed due to excavation	34	0.312	API 5L - coal tar coat	1968	Other outside force damage – dent with stress riser resulting in through wall crack	150	654
ENBRIDGE PIPELINES (NORTH DAKOTA) LLC	STANLEY, North Dakota 13/9/2011	CRUDE OIL	Other	Stanley Station	~	~	~	~	~	Miscellaneous – Residue inside a casing	~	~

Note: HVL* = HVL or other flammable or toxic fluid which is a gas at ambient conditions

Table 26: PHSMA – Incidents in casings 2002 to 2009 for hazardous liquids pipes

Operator	Location / Date	Location	Leak size	Cause	Material in pipe	Pipeline name	Nominal pipe diameter (inch)	Wall thickness (inch)	Pipe spec	Date laid	Incident pressure (psig)	MOP (psig)
SHELL PIPELINE CO., L.P.	HOUSTON, HARRIS, Texas 15/9/2009	CASED ROAD CROSSING	Pinhole	Construction defect – Material and/or weld failures – Butt Weld	DIESEL / GASOLINE MIX	SINCO PRODUCTS SYS	12.75	0.25	B	1982	71	830
ONEOK NGL PIPELINE LP	MEDFORD, GRANT, Oklahoma 25/11/2008	Inside a casing	Pinhole	Construction defect - Material and/or weld failures – Body of pipe	ETHANE / PROPANE MIX	LINE 4	12.75	0.22		1987	1365	1440
CRIMSON PIPELINE L.P.	LONG BEACH, LOS ANGELES, California 20/11/2006	In casing under railroad tracks	Pinhole	Corrosion external – water in casing - CP installed 1966	CRUDE OIL	THUMS 10-INCH PIPELINE	10	0.22	API 5L X52 – coated	1966	100	1200
SHELL PIPELINE CO., L.P.	BAKERSFIELD, KERN California 11/03/2003	IN CASING	Pinhole	Corrosion external - moisture	CRUDE OIL	BAKERSFIE LD, 10K151	10.75	0.31	GRADE B - coated	1930	950	200

Table 27: PHSMA – Incidents in casings 1986 to 2001 for hazardous liquids pipes

Operator	Date	Location	CAUSE	Date laid	Nominal diameter (inch)	Wall thickness (inch)
OILTANKING OF TEXAS PIPELINE CO	09/07/1996	HARRIS, Texas	FAILED PIPE - DAMAGE BY NATURAL FORCES	1978	24	0.28
MID - VALLEY PIPELINE CO	25/6/1990	ALLEN, Ohio	FAILED PIPE – leak in casing	1949	22	0.38
AMOCO OIL CO	24/8/1986	HARRISON, Iowa	External corrosion – shorted railroad casing	1941	6	0.25
ARCO PIPE LINE CO	18/10/1993	MACON, Missouri	External corrosion – atmospheric	1938	8.63	0.32
ARCO PIPE LINE CO	05/10/1993	CHARITON, Missouri	External corrosion – atmospheric	1929	8.65	0.32
OXY USA INC	08/09/1991	CALCASIEU, Louisiana	OTHER	1956	6.63	0.19

A further spreadsheet was found for hazardous liquids at http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/liquid0102.zip

This spreadsheet summarises data for many incidents on liquid carrying pipelines. The spreadsheet was interrogated for incidents involving casings and three incidents were found. The salient points for these three incidents are summarised in the table below. These three incidents are already recorded in the flagged incident database outlined above for the time period 2002 to 2009.

Table 28: Extract from PHMSA liquid incident database

Date	Location	Operator	Fluid	Failure cause	Hole size	Pipeline	Date constructed	Operating pressure (PSIG)	Wall thickness (inches)	Steel grade	Coating
11/3/2003	Bakersfield, CA	SHELL PIPELINE CO., L.P.	CRUDE OIL	External corrosion – localised pitting – moisture	Pinhole	BAKERSFIE LD, 10K151	1930	950	0.31	GRADE B	Coated
20/11/2006	Long Beach, CA	CRIMSON PIPELINE L.P.	CRUDE OIL	External corrosion – general corrosion – water in casing	Pinhole	THUMS 10-INCH PIPELINE	1966	100	0.22	API 5L X52	Coated
25/11/2008	Medford, OK	ONEOK NGL PIPELINE LP	ETHANE / PROPANE MIX	Material and/or weld failure – construction defect	Pinhole	LINE 4	1987	1365	0.22		

Further spreadsheets were found covering the period up to 1986 for gas transmission and liquid pipelines http://phmsa.dot.gov/pipeline/library/data-stats None of the incidents for the gas transmission pipelines indicated an incident at a casing, whereas three were found for liquid pipelines.

Table 29: PHMSA – Liquid pipeline incidents to 1986

Operator	Date	Location	Cause	CDMG	Fluid	Nominal pipe diameter (inch)	Wall thickness (inch)	Pipe spec	Date laid
LAKEHEAD PIPE LINE CO	08/01/1979	Leonard, Oakland, Michigan	DEFECTIVE PIPE	CASING PIPE, REMOVED	CRUDE OIL	30	0.25	X52 Coated	1976
CONTINENTAL PIPE LINE CO	18/01/1979	Luther, Oklahoma	External CORROSION	PIPE INSIDE CASING	CRUDE OIL	8	0.322	B NOT Coated	BETWEEN 1920 AND 1930
STANDARD OIL CO	26/01/1979	None given, Ohio	EQUIPMENT RUPTURING LINE	PIPELINE &CASING	JET FUEL	6	0.188	X42 Coated	1962

c) Miscellaneous other incidents

This section presents details of other incidents where only limited amount of information has been found

Monroe, 1974

On 2 March 1974, a 30” diameter gas pipeline operating at 797psig failed inside a 34”diameter casing pipe beneath a road near Monroe, Louisiana. A substandard girth weld was identified as the cause. The failure of the automatic valves on the pipeline to close following a pressure drop was also cited in contributing to the size of the accident.