A collaborative innovation project final report

Asset Health Modelling (Pipelines, Special Crossings & Block Valves)

A collaboration between:

Wales & West Utilities (Lead GDN)
Northern Gas Networks
National Grid Gas Plc
SGN
Pipeline Integrity Engineers Ltd

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Executive Summary

Following submission of the Gas Distribution Network's (GDN's) business plans, Ofgem recognised the significant work carried out by the GDNs to report asset health, probability of failure and deterioration. However, it was recognised that the framework did not provide consistent results between the GDNs. Ofgem intended the framework to provide a consistent means of comparing information between GDNs and enable GDNs to compare information about the condition of assets over time. In addition, Ofgem sought evolution over time to combine information from different asset classes to form an overall view of the condition of GDN assets and risk therein.

Currently each GDN has derived individual methodologies which they have developed independently of each other. To provide the consistency that the license condition requires, the Safety & Reliability Working Group (SRWG) have been working to derive a consistent methodology for 47 agreed asset groups for reporting to Ofgem by July 2015. For many asset groups, the SWRG have derived 'simple' methodologies. For the more complex asset groups, a more complex methodology is required and the SWRG have established that external consultation is required.

This project looked to overcome the problem of reporting the health and criticality of one of the key group of assets - Local Transmission Pipeline assets; comprising the pipelines themselves plus all the associated assets such as block valves, special crossings and sleeves. The SRWG engaged with the industry experts in PIE due to the inherent knowledge that they held plus the level of interaction that they already had with the GDNs through the UKOPA (United Kingdom Onshore Pipeline Operators Association) group.

PIE was able to use existing data previously reported through UKOPA plus additional pooled data that the GDNs have collected for these assets. They then used this data plus their expert knowledge to derive modelled methodologies for deriving the probability of failure of each of the assets. These probability of failure figures were then used to derive the health index of each of the asset type.

Due to the broad range of assets encountered during this project, different methodologies were used for each asset type although they were based on the same principles. For example the pipeline assets used data found from on-line inspections and maintenance records while sleeves and crossings used age based data. All models used the principle that assets deteriorate over time but at different rates due to the various factors at play.

The service provider has diligently researched each of the GDNs current approach to asset health assessments and has provided a solution which will fit all the GDNs use.

The final results of the models were then tested against each of the GDNs asset base to check that the results were consistent with expected asset performance and intervention plans.

The project was delivered on time and to budget. The methodologies were submitted to Ofgem in line with our obligations.

This project has delivered a health index and probability of failure score for current and future years on all of the assets within this project scope being Pipelines, special crossing & block valves).

The deliverables from this project will be used as the foundations for future projects to develop the asset health methodologies to fully deliver within this field of asset management.

Contents

Technical Note PIE/14/TN113:- Development of a Model for Classifying the Health Index of Non-Piggable Pipelines

1. Summary

As part of the process to classify assets for Ofgem, the proposed Health Index (HI) classification for non-piggable pipelines is as follows:-

Category	Ofgem Description
HI1	New or as new
HI2	Good or serviceable condition
HI3	Deterioration: requires assessment or monitoring
HI4	Material deterioration: intervention requires consideration
HI5	End of serviceable life: intervention required

The proposed methodology is based on the Intervals2 approach which was used for assessing the required interval for in-line inspection. This approach uses the probability and rate of corrosion, in applying it to non-piggable pipelines the timescale considered is increased to cover the current age of the pipeline. This also allows the future HI to be assessed based on continuing strategies, or with additional intervention.

2. Background

Failure mechanisms causing loss of gas from pipelines are generally caused by:-

1. External interference
2. External corrosion
3. Mechanical defect – material or construction defects
4. Ground movement
5. Other – including operational failures due to over-pressure, pressure cycling etc.

These mechanisms are prevented as far as possible by design, manufacturing and routing for a new pipeline, and surveillance, inspection and maintenance activities during the lifetime of the pipeline.

The main failure mechanism which is subject to deterioration with age for natural gas pipelines is external corrosion.

The primary protection against external corrosion is the external coating of the pipeline, with a secondary level of protection provided by cathodic protection (CP). The CP imposes a small DC voltage onto the pipeline surface so that if coating breakdown occurs, a sacrificial anode corrodes preferentially rather than the pipe wall.

Detecting corrosion for most pipelines is carried out by undertaking In-Line Inspection (ILI at a frequency determined by the Intervals2 methodology. ILI involves sending an intelligent pig through the pipeline to detect metal loss features. In addition over-ground surveys are carried out with sensitive electronic equipment to detect where coating breakdown may have occurred (CIPS, DCVG).

However there are a significant number of non-piggable pipelines where ILI is not possible, and then the only means of detecting external corrosion is over-ground surveys.

3. Characteristics of External Corrosion

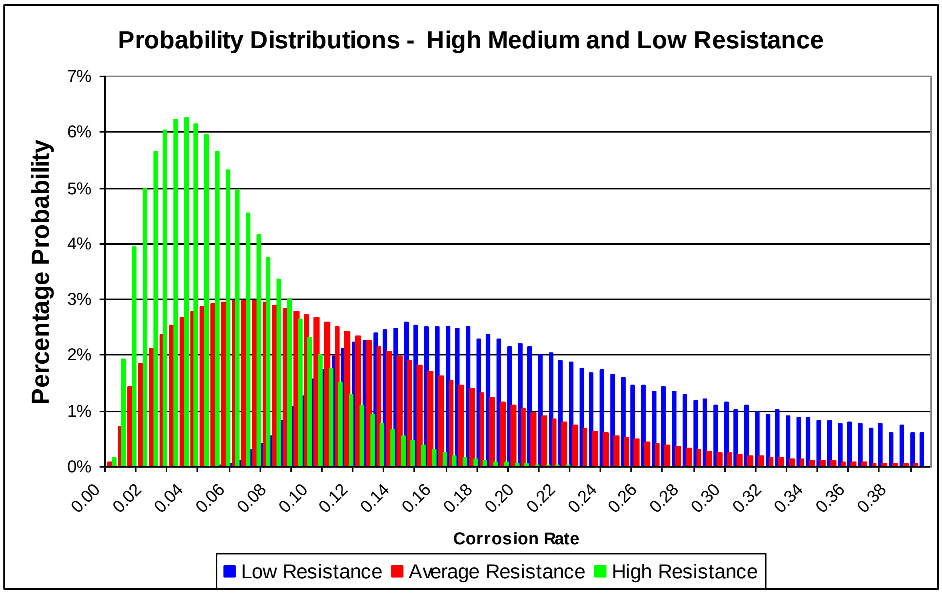
Data from faults detected by ILI have been compared with faults from non-piggable pipelines and this shows that approximately 50% of corrosion faults may be detected in some non-piggable pipelines (Ref 1, 2). Reports similar to references (1, 2) are no longer produced, but the findings are considered to remain valid, as the reduced detection rate occurs because external inspection techniques applied from the ground surface above the pipeline survey the top half of the pipe only.

Once a coating defect has occurred and cathodic protection becomes less effective, corrosion is a gradual process reducing the effective thickness of the pipe wall.

Therefore the remaining pipe wall thickness is a measure of the residual life of the pipeline.

Once through-wall corrosion has occurred, a gas leak will occur. If corrosion has occurred over a large area, a larger release, or pipeline rupture could occur, although this is less likely than a leak.

The rate of corrosion is dependent on a number of factors, including degree of coating damage or deterioration, effectiveness of the cathodic protection system, length of time before the defect is detected (i.e. probability of it being detected, and corrosivity of the surrounding soil. Previous recorded studies on the annual corrosion rate in the UK have determined the following probability curves for high, average and low corrosion resistance:-



Note – the corrosion rate is given in mm/year.

These curves were used in the Intervals2 program to determine the require pipeline in-line inspection intervals to reduce the probability of corrosion defects exceeding specified limiting depths. The curve to be applied is defined by the effectiveness of detection and correction procedures applied to each specific pipeline.

4. Application to Non-Piggable Pipelines

A simplified approach based on these corrosion curves has been applied to non-piggable pipelines.

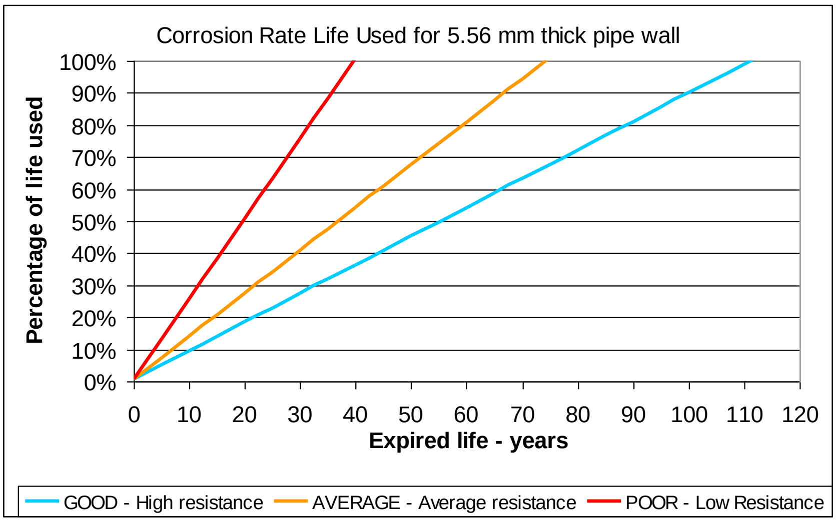
1) Three corrosion rates are applied based on the model[1] of the corrosion curves shown above.

- High corrosion resistance – as defined by quality of 5-Yearly Inspections (see Appendix 1, Ref 3) and follow up work – defined as CIPS = GOOD, corrosion rate is then 0.05 mm per year

- Average corrosion resistance – as defined by quality of 5-Yearly Inspections and follow up work – defined as CIPS = AVERAGE, corrosion rate is then 0.075 mm per year

- Low corrosion resistance – as defined by quality of 5-Yearly Inspections and follow up work – defined as CIPS = POOR, corrosion rate is then 0.14 mm per year

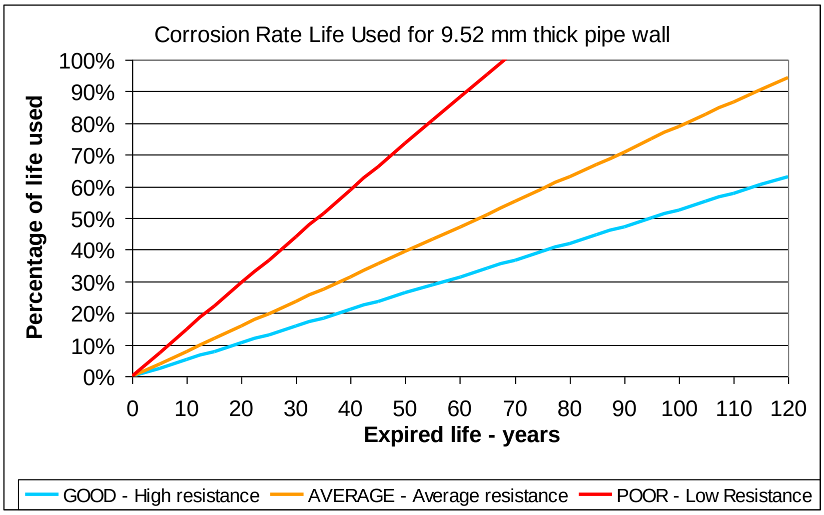
So for a pipe wall thickness of 5.56mm the following life can be expected:-



A further option has been included which allows for INTERVENTION (see Appendix 2, Ref 4) – detailed inspection of the pipeline route including crossings and sleeves to be able to demonstrate that the pipeline condition is verified as GOOD, in which case the corrosion rate during the life of the pipeline so far is assumed to have be 0.05 mm/year, and the number of previous corrosion defects is reset to zero.

For thicker wall pipe, the life time is therefore longer, as shown for a 9.52mm pipe wall below:-

[1] MODE - the value that has the highest frequency within a statistical range



2) **The corrosion rate is then modified to take account of 3 factors:-**

a) Type of coating - Operating experience has shown that different coatings deteriorate in different ways, resulting in more coating defects for some coatings.

A detailed analysis of leaks and faults from the UKOPA fault database derives the following factors to be applied to the corrosion rate for different coating.

Coating Type	Factor
FBE / Epoxy	0.5
Coal Tar	1
Polythene	1.1
Bitumen / Other / Unknown	1.2

b) Number of Recorded Corrosion Defects - The second multiplier factor is related to the number of recorded corrosion defects which were identified during various surveys and subsequently excavated (i.e. recorded faults in the UKOPA Fault Database).

The following multiplier factors are applied to the corrosion rates:-

Number of corrosion faults	Factor
0 corrosion faults	1
1 corrosion fault	1.3
2 corrosion faults	1.35
More than 2 corrosion faults	1.4

These are based on the evidence of pipeline operation so far – if even a single serious corrosion defect has occurred, it indicates that the environmental conditions and / or the original pipeline and coating condition may be allowing corrosion mechanisms to occur, so the risk of undetected corrosion occurring is higher. Therefore there is a step change in risk if 1 serious defect has been recorded, and this is increased further for 2 and more such defects.

The factor for number of corrosion defects is further modified for 2 further input data items, as follows

- **Percentage of the pipeline length covered by the last CIPS / DCVG survey** – If the survey was only able to cover, say 90% of the route, there is 10% left unchecked. Therefore if 1 or more previous corrosion defects have occurred, there is an increased risk of corrosion in the unchecked portion of the pipeline route.

  Mathematically this is taken into account by increasing the factor by the dividing by the proportion of the route surveyed.

  So if 90% of the route was surveyed the following factors are applied:

Number of corrosion faults e.g. 90% of route surveyed	Factor
0 corrosion faults	1
1 corrosion fault	1.3 / 0.9 = 1.44
2 corrosion faults	1.35 / 0.9 = 1.5
More than 2 corrosion faults	1.4 / 0.9 = 1.56

- **Number sleeves if the pipeline was commissioned before 1964** The UKOPA draft report on sleeves (Ref 5) Table 17 draws attention to bitumen or coal tar coating pipeline sleeves in non-piggable pipelines as "critical". Therefore the number of such sleeves in pre-1964 pipelines is included as an input data items for this study.

  Mathematically the number of sleeves is taken into account by increasing the corrosion faults factor by the increasing the factor by 10% for each sleeve, due to the increased likelihood of corrosion between sleeve and pipe wall.

  So if 6 sleeves are recorded for a pre-1964 pipeline, the following factors are applied:

Number of corrosion faults e.g. 6 sleeves to be included	Factor
0 corrosion faults	1
1 corrosion fault	1.3 x (1 + 6 x 0.1) = 2.08
2 corrosion faults	1.35 x (1 + 6 x 0.1) = 2.16
More than 2 corrosion faults	1.4 x (1 + 6 x 0.1) = 2.24

c) Previous operation on Town's Gas service – and therefore a higher risk of stress corrosion cracking-type corrosion defects.

For cases where previous Town's Gas service is identified as "Yes", the recorded pipe wall thickness is reduced by 20% (Ref 6). This effectively shortens the life before reaching HI4 and HI5.

5. Results Calculation

The overall residual pipeline life is calculated using a spreadsheet function so that different residual life results are obtained as follows:-

OLI4 NON-ILI PIPELINES HEALTH & CRITICALITY MODEL - Version 0.6 - March 2014

	OLI4 Pipelines	12 March 2014			dropdown list			dropdown list	dropdown list				
	NOTE items in red are estin	Information	Information	Information	Information	Information	Information	Information	Information	Information	Information	Information	Information
	and need to be corrected / c Pipeline / Section Name	Commiss Year	Length km	Wall Thickness mm	Reports from last 2 CIPS	Percentage of length covered by last CIPS	Total Number of historical Corrosion Faults	Type of pipeline coating	previous Towns Gas SCC?	Number of Sleeves for pre-1964	Percentage Life Used to	Calculated Health Index	previous
	1	2	3	4	5	6	7	8	9	9	14/03/2014		assessment
1	Pipeline No 1	1969	2.54	10.3	Average	90	3	Coal Tar	No/Unknown		51	HI2	HI2
2	Pipeline No 2	1970	0.055	9.7	Average	95	1	Polythene	No/Unknown		51.2	HI2	HI2
3	Pipeline No 3	1971	10.29	11.9	Poor	100	2	Coal Tar	No/Unknown		68.3	HI2	HI2
4	Pipeline No 4	1980	21.07	4.78	Good	85	0	Polythene	No/Unknown		39.1	HI2	HI2
5	Pipeline No 5	1970	0.1	4.85	Average	80	0	Polythene	No/Unknown		74.8	HI2	HI2
6	Pipeline No 6	1962	9.64	5.6	Average	100	1	Coal Tar	No/Unknown	2	108.6	HI5	HI2
7	Pipeline No 7	1977	25.854	5.6	Average	100	0	Coal Tar	No/Unknown		49.6	HI2	HI2
8	Pipeline No 8	1971	13.92	14.3	Poor	100	2	Coal Tar	No/Unknown		56.8	HI2	HI2
9	Pipeline No 9	1970	0.075	7.05	Average	95	0	Polythene	No/Unknown		51.5	HI2	HI2
10	Pipeline No 10	1966	8.8	6	Average	95	1	Coal Tar	No/Unknown		82.1	HI3	HI2

6. Allocation of Health Index

The final step is to allocate Health Index according to the pipeline residual life (and therefore wall thickness).

A detailed analysis of 960 non-piggable OLI4 pipelines has been carried out to obtain the depth of a corrosion defect (as a proportion of wall thickness) at which the ASME B31(G) correlation would predict that an infinitely long defect would cause pipeline failure.

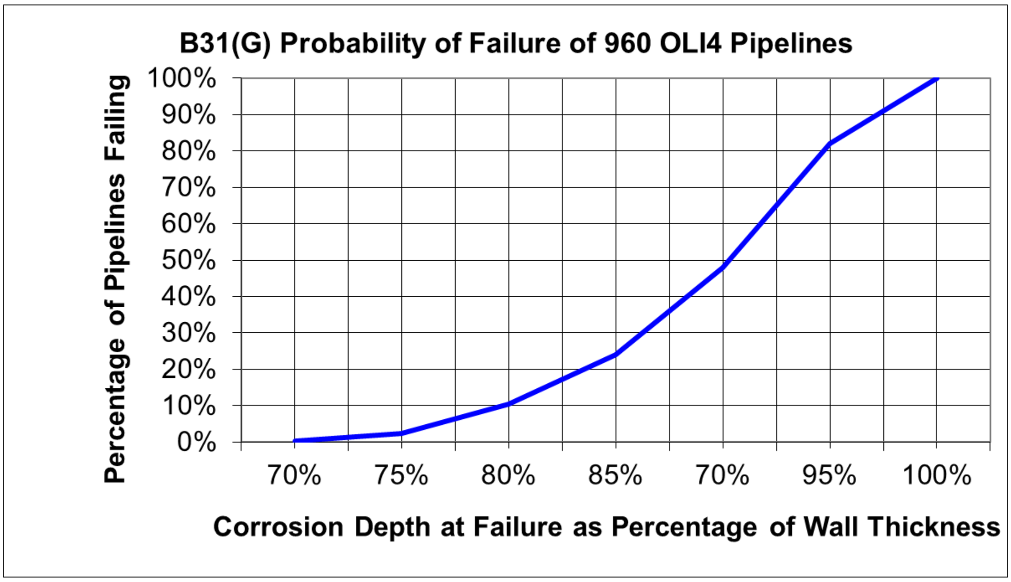
The equation applied is as shown below

$$d = t\left[1 - \left(\frac{P}{\sigma_y + 68.95}\right)\left(\frac{D}{2t}\right)\right]$$

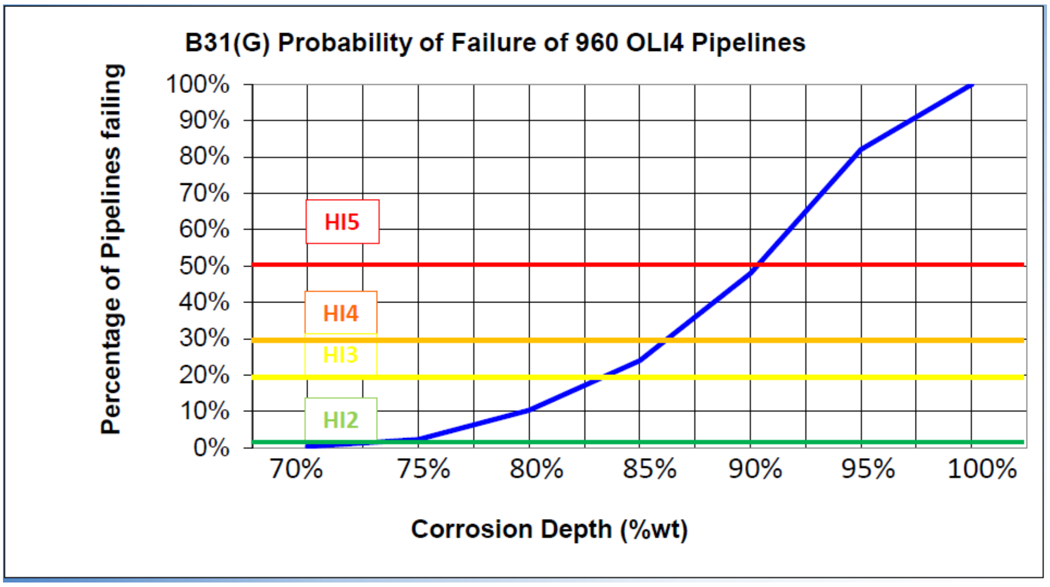
Where d is defect depth, P is MAOP, σ_y = SMYS, D = minimum diameter, and t = wall thickness.

For Intervals2, a safety factor of 90% of this depth is applied to allow for the inspection tool tolerance, tolerance, but for this study, 100% B31(G) depth has been applied.

The result of the analysis shows that the probability of failure varies across the population of pipelines as shown below.



Health Index categories have therefore been applied as shown below:-



The allocation is as follows:-

Health Index Definition	Health Index
Life used < 20 years and commissioned after 1999	HI1
Life used between 20% and 75%	HI2
Life used between 76% and 83%	HI3
Life used between 83% and 90%	HI4
Life used > 90%	HI5

7. Categorisation due to Fatigue Damage

The fatigue life of a transmission pipeline needs to be considered to ensure that any defect which survives the hydrostatic test, or which is not detected by subsequent on-line inspection, does not grow to a critical size under the influence of pressure cycling or other sources of cyclic loading.

A simplified approach for consideration of the fatigue life is provided in IGEM/TD/1 (Ref 7). This is based on the pipeline surviving a high level hydrotest, which limits the size of defect that can be present at the start of life. There are circumstances where a more detailed approach is required. These include:

- When the desired hydrotest pressure has not been achieved.
- When the actual fatigue cycling exceeds that assumed in the design.
- When uprating a pipeline.
- When revalidating a pipeline at the end of its design life.

The procedure for the detailed assessment of pipeline fatigue life is given in Ref 8.

The primary damage mechanism which limits the operating life of transmission pipelines is external corrosion, so the Health Index of transmission pipelines is predicted using an external corrosion model. In some cases, where pipelines are subject to a large number of pressure cycles, it is feasible that the Health Index may be influenced by the resultant accumulated fatigue damage.

The calculation of fatigue damage is summarised in Appendix 3. The total accumulated fatigue damage is recorded by the GDNs for compliance with the Pressure Systems Safety Regulations. Using the total fatigue damage records, the following categorisation is applied:

Total fatigue damage ≥ 0.33, HI = 3
Total fatigue damage ≥ 0.66, HI = 4
Total fatigue damage ≥ 1.0, HI = 5.

8. Input Data Required

The following input data is therefore required to obtain the Health Index for non-piggable pipelines:-

1) Pipeline commissioning year
2) Pipeline wall thickness
3) Assessment of the last 5-yearly OLI4 Inspection Reports.

The following questions help allocate the correct category to apply for HI assessment:-

1	Have the last 2 Inspections been carried out at 5 yearly (or less) intervals? Yes/No
2	Are the reports from the last 2 Inspections available to be assessed? Yes/No
3	Have all the actions from the last 2 Inspections been assessed / carried out? Yes/No
4	Were ZERO serious corrosion defects recorded from the last 2 surveys? Yes/No
5	Were all corrosion defects (if any) investigated and if necessary were excavations and remedial measure implemented? Yes/No
6	Is this pipeline free of any known history of serious corrosion mechanisms (coating disbonding, MIC, AC/DC corrosion)? Yes/No
7	Are regular Test Point survey results available?
8	Is the Cathodic Protection system known to be compliant with ECP" Yes / No
If the answer to all 8 questions is YES – the CIPS reports entry is GOOD	
If the answer to 5, 6 or 7 questions is YES – the CIPS reports entry is AVERAGE	
If the answer to 4 or less questions is NO or UNKNOWN – the entry is POOR.	

4) Percentage of the length of the pipeline route which was covered by the last CIPS survey
5) Coating type
6) Number of historical corrosion defects which were excavated for investigation – these should be obtained from 5-Yealy Inspection reports and (if recorded) the UKOPA fault database.
7) Whether the pipeline was operated on Town's Gas.
8) For pipelines commissioned before 1964, the number of sleeves along the length of the pipeline.
9) Total accumulated fatigue damage.

9. Conclusions

The methodology described above provides a simple rapid method to assess the life used and therefore the health index classification for non-piggable pipelines. The method is based on allocating an annual corrosion rate which eventually causes the pipeline wall to reduce to zero. The two main parameters are therefore pipeline age and wall thickness, and the annual rate of corrosion is influence by 5-Yearly Inspection reports, percentage of the route covered by CIPS survey, type of coating, number of recorded corrosion faults, whether the pipeline was operated on Town's Gas, and for pre-1964 pipelines, number of sleeves.

The allocation of Health Index is set by the life used, such that above 95% of life used the pipeline is considered at "end of service life" and intervention is required. The methodology has included a CIPS categorisation of "INTERVENTION" which represents a significant expenditure on surveys and inspections such that the life can be extended by proving / demonstrating that the actual corrosion rate has been lower than the previously assumed rate.

10. References

1 “Review of Pipeline Operational Fault Data Up To 1st January 1995”, GRTC R 1429, December 1997.

2 “Report by the Pipelines Operations Engineer”, ENC 92/533, April 1992.

3 “Management Procedure for Monitoring the Condition of High Pressure Steel Pipelines Externally”, T/PM/OLI4, January 2006.

4 “Management procedure for Cathodic Protection of Buried Steel Systems” T/PM/ECP/2, May 2006.

5 “Ranking Scheme for Prioritising the Inspection of Pipeline Sleeves” Report Number: 13065, GL Noble Denton, 16th August 2013.

6 “Comments on EOG 90/350 ‘Stress Corrosion Cracking in Pipelines Formerly Used to Carry Towns or Reformer Gas’ ERS R.4473 September 1990.

7 “Steel Pipelines and Associated Installations for High Pressure Gas Transmission” IGEM/TD/1 Edition 5. Institution of Gas Engineers and Managers Communication 1735. 2008.

8 “Specification for Assessing the Fatigue Life of Transmission Pipelines in Accordance with IGE/TD/1”, T/SP/TR/19. October 2005.

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August 2014

Appendix 1 Procedures for 5-Yearly Inspection of Non-Piggable Pipelines

The Management Procedure for Monitoring the Condition of High Pressure Steel Pipelines Externally, T/PM/OLI4 details the procedures for the 5-yearly inspection of non-piggable pipelines.

The procedures necessary to verify the integrity of OLI4 pipelines combines five basic inspection techniques. All areas of the pipeline should undergo a form of inspection.

1 Examination of records

An essential pre-requisite to undertaking survey work is to make an assessment of the overall pipeline condition by examination of the pipeline records to ensure that all known and observable features are taken into account during the audit survey.

As a minimum the following records should be viewed:

- IGE/TD/1 Maximum Operating Pressure Affirmation Reports
- Previous Survey Reports
- New Works, Modifications and Repairs Register
- Cathodic protection routine monitoring information
- Pipeline excavation data

Specific aspects which could adversely affect the corrosion resistance of the pipeline such as CP shielding, pipe coating disbonding, corrosion within sleeves, microbial influenced corrosion, AC and DC interference may not be located using current routine above ground survey techniques. Therefore, their potential presence shall be considered at this time.

2 Coating defect survey

A coating defect survey should be undertaken by using either Pearson or Direct Current Voltage Gradient techniques. A Pearson type survey will locate open coating defects on the pipeline. DCVG survey can be more reliable than Pearson survey for locating coating defects where AC interference effects are present. The use of DCVG can lead to a situation where numerous small coating defects are located. In such cases following excavation of the largest defects, it may be possible to prove that the remaining indications have a negligible effect on pipeline corrosion and can be discounted. However in areas where AC interference effects are present it is the smallest defects that pose the highest risk to pipeline integrity and shall be given a high priority for excavation and inspection.

3 Cathodic protection system

A polarized potential survey can assess the effectiveness of the cathodic protection system. A close interval potential survey (CIPS) is the appropriate procedure for most pipelines. Where a pipeline is protected by distributed sacrificial anodes such that the true polarized potential cannot be measured, a survey measuring only 'on' potentials should be carried out. Polarized potentials should then be measured using buried coupons at test points and/or at areas of low level of protection identified during the above 'on' survey.

4 Supplementary audit techniques

It may not be possible to apply the survey methods outlined above in areas such as street works, road or rail crossings, areas of electrical interference etc. In such circumstances supplementary survey techniques should be employed at all applicable areas to provide a level of confidence that the entire pipeline is unlikely to be affected by corrosion.

Supplementary survey techniques presently available are:
a) Current attenuation
b) Monitoring nitrogen sleeve pressure
c) Long range ultrasonic examination

a) Current attenuation
Current attenuation survey will in many instances be the most useful supplementary technique employed to ensure that the pipeline is unlikely to be affected by corrosion by providing a qualitative assessment of pipeline coating integrity. By comparing the current attenuation of the pipeline approaching and leaving the pipeline crossing, where CIPS or Pearson has been undertaken, with the current attenuation of the actual pipeline crossing, an assessment of the coating integrity can be made.

b) Monitoring nitrogen sleeve pressure
In the case of nitrogen filled sleeves the prevention of corrosion to the gas carrier pipeline, inside the sleeve, is achieved by maintaining a positive nitrogen pressure within the annulus to provide an inert atmosphere. The presence of hydrogen found within the sleeve annulus may point to active corrosion taking place.

c) Long-range ultrasonic examination
Long-range ultrasonic examination can be used as a screening tool to inspect lengths of pipe in order to identify whether areas of corrosion or erosion may be present on both the outside and inside pipe surfaces where access is difficult or as an additional technique to confirm or not the existence of possible features detected by other survey techniques.

d) External pipe wall inspection

5 Reporting above ground surveys

A report of above ground surveys is generated recording the surveys and resulting remedial actions and retained for future reference.

FREQUENCY OF OLI4 INSPECTIONS

An initial examination shall be carried out within 12 months of commissioning. This examination will form the basis of future examinations.

Thereafter, the examination frequency shall be no greater than 5 yearly.

Pipelines operating at stress levels exceeding 30% SMYS

- A survey for coating defects shall be carried out over the entire length of pipeline being audited.
- A close-interval polarized potential survey shall be carried out over the entire length of the pipeline being audited.
- All locations of coating defects identified by the Pearson-type survey should be excavated and an external pipe wall inspection carried out
- All locations of coating defects located using Pearson survey or DCVG at areas where the CP is not effective shall be excavated and an external pipe wall inspection carried out - Coating defects identified by DCVG should be evaluated by benchmarking and actioned - Areas of concern raised by supplementary audit technique(s) shall be investigated and necessary remedial action undertaken.
- Following the repair of coating and other defects, a re-survey for a minimum distance of 100 metres, centred over the defect, should be carried out to prove that the originally detected fault(s) have been rectified.

Pipelines operating at stress levels not exceeding 30% SMYS, see figure 2.

- A close interval polarized potential survey shall be carried out over the entire length of the pipeline
- Where the polarized potential does not meet the criteria for effective CP, a coating defect survey should be carried out.
- All locations of coating defects located using Pearson survey or DCVG at areas where the CP is not effective shall be excavated and an external pipe wall inspection carried out - Areas of concern raised by supplementary survey technique(s) shall be investigated and necessary remedial action undertaken.
- Following any repair work, and after consolidation of the backfill, remedial action shall be taken where necessary to ensure that the pipeline meets the criteria for effective CP
- Following the repair of coating and other defects, a re-survey for a minimum distance of 100 metres, centred over the defect, should be carried out to prove that the originally detected fault(s) have been rectified.

Appendix 2 – Proposed Process for Defining "Intervention" to Extend Pipeline Life

Intervention Process is required to demonstrate that HI4 or HI5 pipeline is in adequate condition to reduce the HI categorisation

Identification of vulnerabilities that are causing high HI - these could be age, coating type, number of faults, Towns Gas operation.

Vulnerable features are sleeves, crossings, areas not accessible to CIPS, proximity of electrical conductors.

<u>Stage 1 – Review Records</u>

Review records (CIPS, test point readings and functional, interim and major surveys etc)

Decision to carry out additional surveys (CIPS + DCVG, Pearson)

Select most vulnerable points on pipeline route from above list

Carry out 'direct assessment' excavations to prove coating condition, remove coating and carry out thickness checks, corrosion calcareous deposit, SCC indications, MIC

Decision to continue investigations?

<u>Stage 2 – Carry Out Additional Surveys</u>

Carry out CIPS if required and DCVG / Pearson surveys to assess coating

Carry out soil resistivity checks, current drain test for crossings (ref ECP2 Appendix I) or electromagnetic current attenuation survey (ref ECP2 Appendix J), carry out polarity checks on CP installations.

Address any locations of low potential, investigate any locations of corrosion interaction, any non-compliances.

Check and confirm functionality of electrical CP system, confirm any interference/interaction issues are addressed, confirm that anodes, CP power source, ground beds etc have been replaced as required.

Investigate areas of high soil corrosivity and take soil samples.

Document results of investigation.

Decision to continue investigations?

<u>Stage 3 – Direct Assessment Investigations</u>

Select most vulnerable points on pipeline route from results of Stages 1 and 2.

Carry out 'direct assessment' excavations to prove coating condition,
remove coating and carry out thickness checks, corrosion calcareous deposit,
SCC indications, MIC indications.

Document results of investigation.

Stage 4 – Document Results and Draw Conclusions

The conclusion from the study – overall corrosion rate is lower than age would suggest, so a lower corrosion rate can be applied, resulting in a lower current HI category.

Appendix 3 – Calculation of Fatigue Damage due to Cyclic Pressure in Transmission Pipelines

Summary of TD/1 Requirements for Pipeline Fatigue Analysis

Simple (SN) Approach

The simple SN design approach is applied to pipelines that i) have been subject to a high level hydrotest and ii) will not experience maximum stress ranges in excess of 165 N/mm^2

(a) Constant daily pressure-cycling

Where the magnitude of daily pressure-cycling is constant, the fatigue life should be determined from:

$$S^3N = 2.93 \times 10^{10}$$

S = constant amplitude stress range ($N\ mm^{-2}$)
N = number of cycles.

(b) Variable pressure-cycling

Where the magnitude of daily pressure cycling is not constant, the fatigue life should be evaluated on the basis of (a) above, by totalling the usage of fatigue life from each stress range.

The following condition for the damage fraction should be satisfied to obtain an acceptable fatigue life.

$$D_F = \Sigma \frac{n_i}{N_i} \leq 1.0$$

n_i = the actual number of cycles accumulated at stress range S_i
D_F = damage fraction
S_i = stress range (see N_i and $n_{i)}$
N_i = number of stress cycles allowed at stress range S_i (clause 6.6.2.1(a)).

If the anticipated value of D_F exceeds 0.5, the actual cycles accumulated during operation should be determined using the Reservoir or Rainflow cycle counting method.

Detailed Fracture Mechanics Approach

In cases where i) the pipeline has not been subject to a high level hydrotest or ii) will experience maximum stress ranges in excess of 165 N/mm^2, or iii) it is required to assess the fatigue life or a defect detected during service, a detailed fatigue assessment is required. The procedure, given in T/SP/TR/19 (Ref 7), requires that a fracture mechanics calculation should be carried out in accordance with BS 7910 to calculate the fatigue life, and the actual cycles accumulated during operation should be determined using the Reservoir or Rainflow method.

Recommendation for Pipeline Fatigue Categorisation

Where the simple SN approach for the calculation of fatigue life can be applied to the pipeline, the following categorisation is recommended:

Total number of equivalent cycles of 125 N/mm^2 ≥ 5,000, HI = 3
Total number of equivalent cycles of 125 N/mm^2 ≥ 10,000, HI = 4
Total number of equivalent cycles of 125 N/mm^2 ≥ 15,000, HI = 5

Where the simple SN approach does not apply and a detailed fracture mechanics fatigue calculation has been carried out, it is recommended that the fatigue damage is calculated as follows:

$$D_t = \sum \frac{n_i}{N_i}$$

and the following categorisation is applied:

Total fatigue damage ≥ 0.33, HI = 3
Total fatigue damage ≥ 0.66, HI = 4
Total fatigue damage ≥ 1.0, HI = 5

Technical Note PIE/14/TN125

Models for Classifying the Health Indices of Block Valves, Sleeves and Above Ground Crossings

1 Summary

The proposed Health Index (HI) classification for the gas network assets is as follows:-

Category	Ofgem Description
HI1	New or as new
HI2	Good or serviceable condition
HI3	Deterioration: requires assessment or monitoring
HI4	Material deterioration: intervention requires consideration
HI5	End of serviceable life: intervention required

Table 1 – Health Index Category Definitions

The Health Index describes a change in condition which is related to the probability of failure (PoF) of the asset. An asset reaches its end of life (EoL) at Health Index 5.

To ensure the Health Index of an asset can be consistently predicted using engineering PoF models, the above definitions have been aligned to PoF and "percentage life used" levels by the Gas Distribution Networks (GDNs) as follows;

Health Index	POF	Life Used
HI1	≤ 0.01	< 20years and commissioned after 1999
HI2	>0.01, ≤ 0.2	between 20% and 75%
HI3	> 0.2, ≤ 0.3	between 76% to 83%
HI4	> 0.3, ≤ 0.5	between 83% to 86%
HI5	> 0.5	> 90%

Table 2 – Health Index PoF and Life Used Definitions

PoF models constructed to derive the Health Index for block valves, sleeves and above ground crossings on high pressure gas pipelines are described in this Technical Note.

2 Probability of Failure Models

2.1 Backgound

PoF relationships for equipment and components are generated through a detailed statistical analysis of the variation of condition or functionality of the item with time (age) or duty. In reality, such data and therefore relationships derived from it are scarce. This means that PoF relationships for specific applications must be developed. The method used depends upon the data availability, for example:

i) Where extensive data is available, statistical analysis is applied to obtain a probability of failure density function, which is then used to derive the probability of failure relationship.

ii) Where limited data exists, an assumed engineering relationship is selected and this is then calibrated using the data available.

iii) Where there is little or no data, a model is selected based on engineering judgement, and predictions obtained are checked against operational data and experience where possible.

Methods ii) and iii) above have been used to develop PoF models for block valves, sleeves and above ground crossings.

2.2 Description of PoF Models

The six standard probability of failure patterns observed in mechanical and electrical equipment [1] are shown in Figure 1.

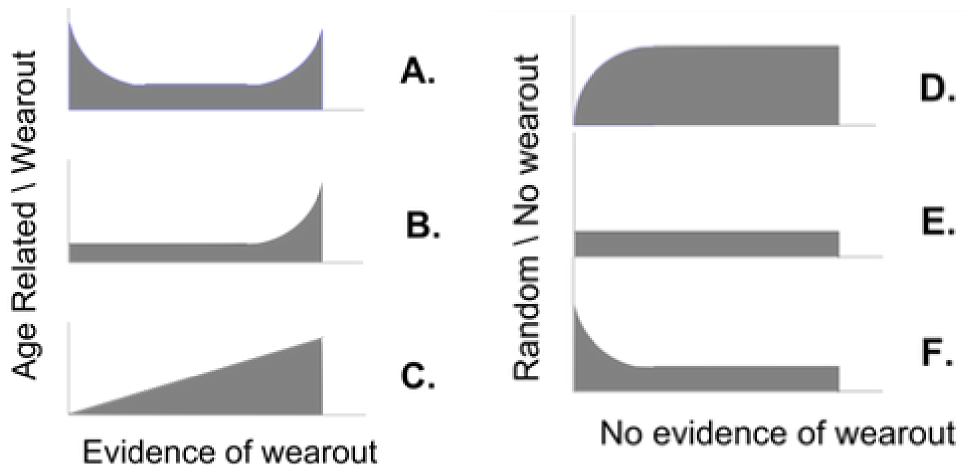

Figure 1 – Six Typical Probability of Failure Patterns

Curve A is the established bath tub curve, curve B shows a constant or slowly increasing failure rate followed by a wear out zone, pattern C shows a slowly increasing probability of failure with no identifiable wear out, pattern D shows a low as new probability of failure which increases quickly to a constant level, pattern E shows a constant probability at all ages (i.e. random failure rate) and pattern F shows a high early failure rate which falls to a constant or slowly increasing rate with age.

As part of the development or its Regulatory Business Plan, Wales and West Utilities (WWU) commissioned EA Technology to develop a Condition Based Risk Management process for quantifying the current and future condition, performance and risk of the company's transmission and distribution assets. The process uses a probability of failure model, which is described in [2]. This model relates the Health Index of the asset to PoF, as shown in Figure 2.

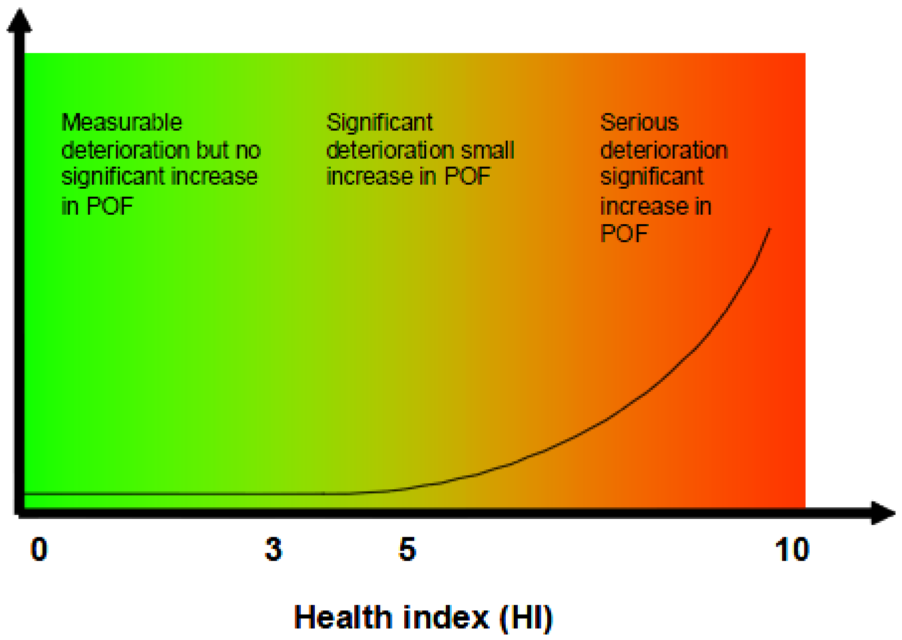

Figure 2 – Relationship between Health Index and Probability of Failure proposed by EA Technology

The relationship shown in Figure 2 is equivalent to pattern B shown in Figure 1. The EA Technology report states that once degradation becomes significant, the risk of failure increases according to a polynomial function, and that mathematical modelling suggests this relationship can be defined by a cubic relationship (ie 3rd order polynomial). The relationship proposed is:

$$PoF = k\left[1 + HI.c + \frac{(HI.c)^2}{2!} + \frac{(HI.c)^3}{3!}\right]$$

Where:

PoF = probability of failure per annum

HI = Health Index

K & c = constants, derived from statistical data

The EA Technology Report states that while practical experience has indicated that the cubic relationship is appropriate for assets with a higher Health Index, at the later stage life, a hybrid relationship is recommended for the full duration of service. In such a model, the PoF is set to a constant value until a limiting value of Health Index is reached, after this point the cubic relationship is applied.

The derivation of the constant c (the slope of the curve) requires measured condition and failure data, and the constant k requires the analysis of the failure rate (numbers of failure per annum).

2.3 PoF Models for Block Valves, Sleeves and Crossings

PoF models for block valves, sleeves and crossings assets have been developed using a simple, hybrid cubic model as proposed by EA Technology. The statistical condition, performance and failure data required to derive the model constants c and k is not available. Consequently, the following simple form of the hybrid – cubic model was proposed to predict the relationship between asset PoF and age:

PoF = 0 for age ≤ 20 years

PoF = $k[(age-20)^2 + (age-20)^3]$ for age > 20 years

The assumption of a constant PoF value for asset lives less than or equal to 20 years was based on the approach used by Northern Gas Networks (NGN). For the initial studies this value was set to zero.

The constant k is calculated by imposing the condition of a set PoF at a given age. For the purpose of the initial model development, this fixed point was set to be a PoF of 1.0 at an assumed EoL age of 60 years. This provided a working model which can be used to provide initial predictions of asset PoF vs. age and hence the Health Index.

When the predicted asset PoF value indicates a health category of HI4 or HI5, the asset health must be assessed and remedial/repair work carried out to reinstate the health index to HI2 (ie good or serviceable condition). The intervention processes required to carry out the asset condition assessment and reassignment of the health index to HI2 are given in Appendices 1 – 5.

The PoF calculation for the asset is then updated at the age at which the intervention process is carried out as follows:

PoF = 1.0 at age (date of completion of intervention process + 60 years)

$$k = \frac{1}{((Age+60)-(age\ at\ intervention))^2} + \frac{1}{((Age+60)-(age\ at\ intervention))^3}$$

PoF = $k[(current\ age - age\ at\ intervention)^2 + (current\ age - age\ at\ intervention)^3]$

3 PoF Model and Prediction of Health Index for Block Valves

3.1 PoF Model for Block Valves

The simple PoF model described in Section 2.3 was used to predict the PoF vs. age for block valves, assuming a fixed EoL of 60 years. This model was used to provide a base line PoF vs. age prediction.

Data for planned and unplanned maintenance for block valves was provided by NGN, this information was used to carry out sensitivity studies, in which the PoF was defined at the age at which either the last planned maintenance giving a satisfactory condition, or the age at which unplanned maintenance was completed.

Planned maintenance activity which resulted in no further action required was assumed to indicate a Health Index of HI2. The requirement for unplanned maintenance activities was assumed to indicate a Health Index of HI3. The data was therefore used to assess whether a relationship between HI and age was indicated. The results are shown in Figures 3 and 4. In addition, data was used to investigate whether the diameter had an influence on the age at which unplanned maintenance is required, i.e. HI3. The results, shown in Figure 5, indicate that the diameter does not influence the age at HI3. It is therefore assumed that the diameter does not influence the PoF vs. age relationship.

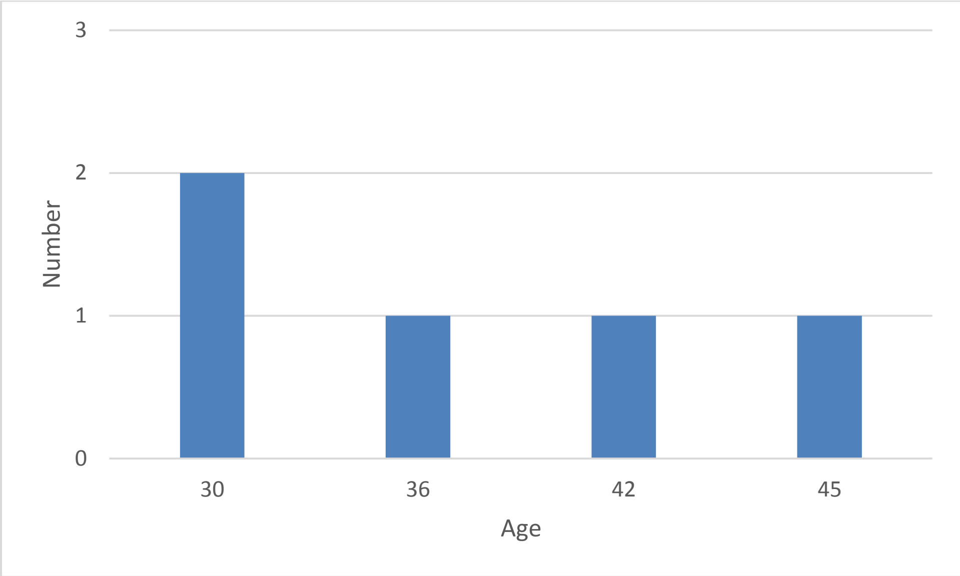

Figure 3 – Block Valve Age at which Planned Maintenance Confirmed Satisfactory Condition, Assumed to Indicate HI2.

Data in Figure 3 indicates that the average age at HI2 is 35 years.

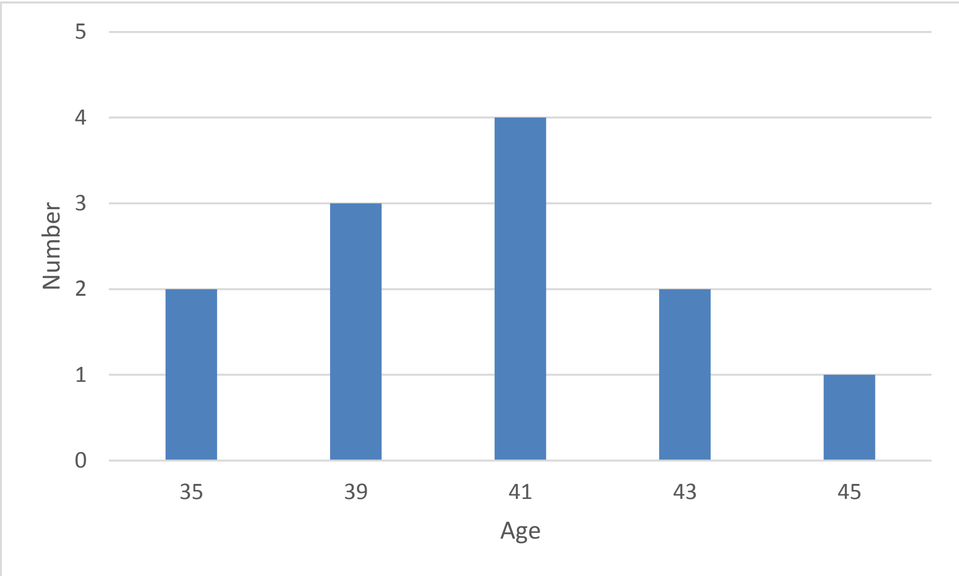

Figure 4 – Block Valve Age at which Unplanned Maintenance was Actioned, Assumed to Indicate HI3.

Data in Figure 4 indicates that the average age at HI3 is 41 years.

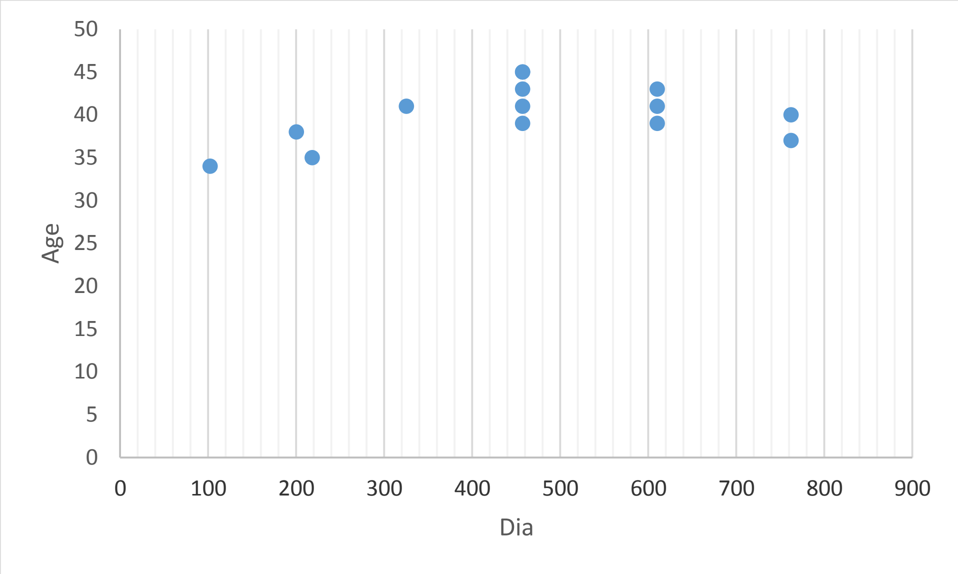

Figure 5 – Influence of Diameter on the Age at which Unplanned Maintenance is Required (HI3)

Using the above results, derivations of the model were developed using the following assumptions:

i) Age at HI2 = 35 years, PoF = 0.1

ii) Age at HI3 = 41 years, PoF = 0.25

iii) EoL = 60 years, PoF = 1.0

Predictions obtained using the different versions of the model are shown in Figure 6.

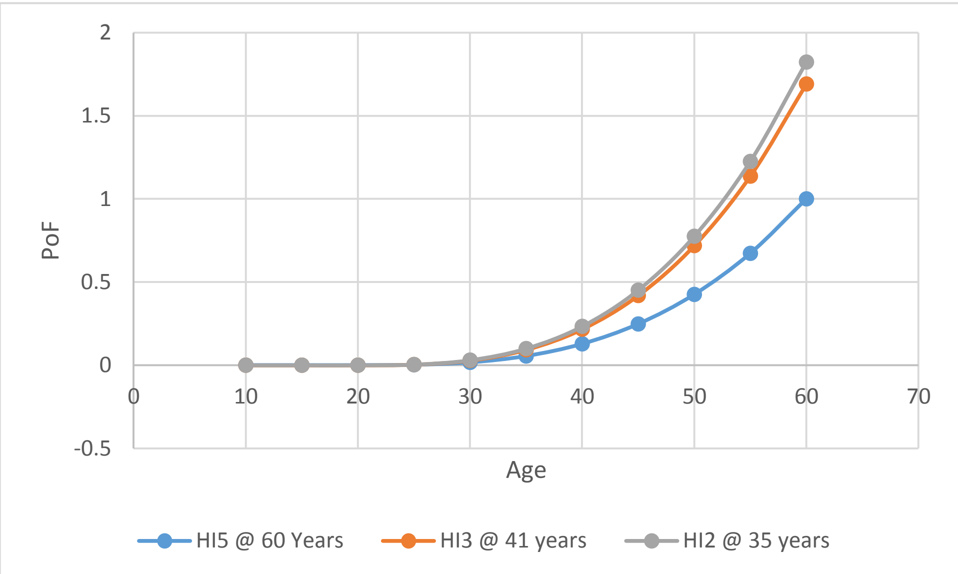

Figure 6 – Block Valve Model PoF vs. Age Predictions

Comparisons of the predictions obtained using models with different assumptions shows that the age at HI2 and HI3 curves are close, and these predict a faster increase in PoF with age. Predictions obtained using the HI3 at 41 years model and the EoL at 60 years model were considered by NGN, who confirmed that the model based on the EoL of 60 years provides a better fit to the NGN assessment. The model derived using an EoL of 60 years has therefore been selected for application by the GDNs.

3.2 Block Valve Health Index Predictions

The simple block valve PoF model requires the age of the block valve and assumes the EoL is 60 years. Predictions have been made using the isolation valves associated with pipelines obtained from the UKOPA database.

The results obtained for the GDNs are given in Table 3:

GDN	HI1	HI2	HI3	HI4	HI5
NGN	3%	26%	40%	31%	0
SGN	7%	17%	21%	38%	17%
UKD	12%	28%	22%	34%	5%
WWU	31%	32%	16%	19%	2%

Table 3 – Percentage of Block Valves in Health Index Categories

4 Prediction of Health Index for Sleeves

4.1 PoF Model for Non-Nitrogen Sleeves

The model for the prediction of PoF of sleeves is based on a development of the simple PoF model described in Section 2.3, incorporating a modification of the leakage factor included sleeve risk ranking model developed by GLND for UKOPA [3].

The UKOPA sleeve risk ranking model calculates a leakage factor based on factors for the coating, sleeve material, end seal type and annular fill material as follows:

Pipeline Coating factors:

Coating Type	UKOPA Sleeve Coating Factor
Coal tar	1.0
Bitumen	1.2
Polyethylene	1.1
Epoxy	0.5
Unknown/ unknown if pipeline coated	1.2
Bare	1.5

Table 4 – UKOPA Sleeve Model Coating Factors

Sleeve Material factors:

Sleeve Material	UKOPA Sleeve Material Factor
Concrete	1.0
Steel	1.2
Other/Unknown	1.5

Table 5 – UKOPA Sleeve Model Material Factors

Sleeve end seal factors:

Sleeve End-seal Type	UKOPA Sleeve End-seal Factor
Rigid	1.0
Flexible	1.1
Shuttering	1.3
Other/Unknown	1.3

Table 6 – UKOPA Sleeve Model End-seal Factors

Sleeve annular fill material factors:

Sleeve Annular Fill Material	UKOPA Sleeve Annular Fill Factor
Concrete/grout	0.8
Thixotropic	1.0
Air/PFA	2.0
Unknown	2.0

Table 7 – UKOPA Sleeve Model Annular Fill Factors

In addition to the coating, sleeve material, end-seal and annular fill factors the UKOPA leakage factor includes the length of the sleeve. Including the sleeve length as a multiple in the PoF model results in the application of very high multiplying factors in the leak factor. To address this, the following factors are used in the sleeve PoF model:

Sleeve Length (m)	Factor
≤10	1
>10≤50	1.1
>50≤100	1.2
>100≤200	1.5
>200≤500	1.75
>500≤1000	2
>1000	4
Unknown	1.2

Table 8 – Sleeve Length Factors used in PoF Model

The sleeve leakage factor is calculated by multiplying the relevant factors given in Tables 3 to 8. The sleeve leakage factor is then included as a multiplier in the simple PoF equation explained in Section 2.3.

The performance of the model was evaluated using a data set for 565 non-nitrogen sleeve provided by NGN. The use of the leakage factor as a multiplier was assessed by comparing the maximum, average and minimum values calculated for the sleeve population, and applied in the PoF calculation for sleeves. The PoF predictions for an assumed sleeve EoL of 60 years are shown in Figure 7. These results show that the range of the leakage factor has a significant effect on the PoF prediction.

The average age of the sleeves in the NGN population was 44 years. PoF predictions obtained using the model derived to represent HI3 at 44 years were compared with the predictions obtained using the model based on EoL of 60 years, in both cases the average leakage factor was applied. The results, shown in Figure 8, indicate that the predictions are close.

Based on the results of the above studies and consideration of the percentage split between each Health Index, as predicted by NGN, the model derived assuming the EoL at 60 years age and using the average leakage factor obtained for the NGN sleeve population was selected for application by all GDNs.

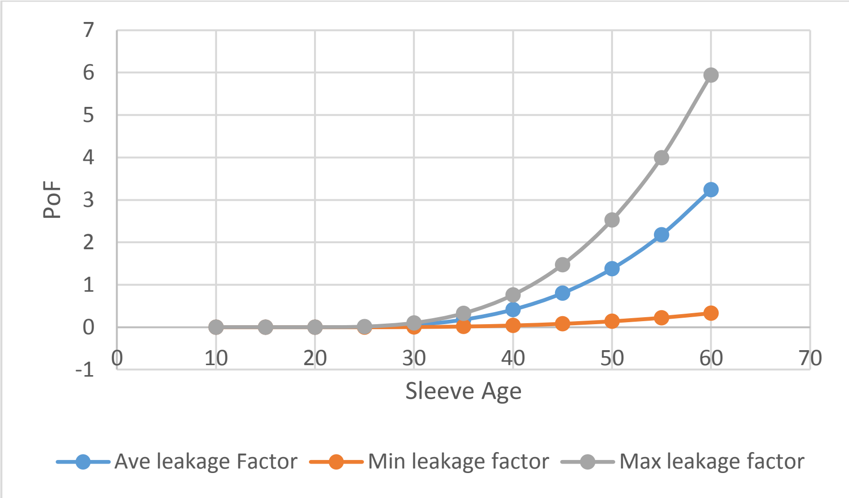

Figure 7 – Sleeve PoF Predictions Assuming EoL at Age 60 Years and Using Minimum, Average and Maximum Leakage Factors

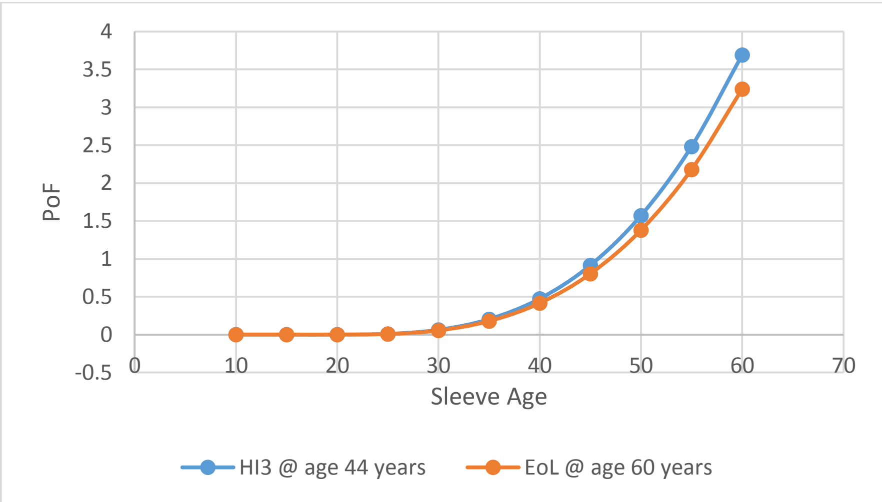

Figure 8 – Sleeve PoF Predictions Assuming HI3 at Age 44 Years and EoL at Age 60 Years, Using the Average Leakage Factor

4.2 PoF Model For Nitrogen Sleeves

The model for the prediction of PoF of nitrogen sleeves is based on a development of the simple PoF model described in Section 2.3.

The GLND report for UKOPA [3] states that maintenance of nitrogen filled sleeves focuses on the monitoring of nitrogen pressure in the sleeve, and that the capability of the sleeve to retain the pressure is dependent upon the end sleeves and the condition of the fill and vent connections. Discussions with the GDNs confirmed that nitrogen sleeves are considered to be high integrity assets, and that pressure monitoring, including sleeves where pressure loss is being monitored, is considered to represent a Health Index category of HI2.

Maintenance data for a population of 107 sleeves nitrogen sleeves provided by NGN was used to assess the impact of the age at HI2 for nitrogen sleeves (data for 7 of the sleeves was not used as the commissioning date is unknown). Data indicating sleeves with no issues and sleeves with reduced nitrogen pressure was used to determine the age of sleeves at the mid-point of the HI2 classification (i.e. PoF = 0.1).The data shown in Figure 9 indicates that the average age is 43 years.

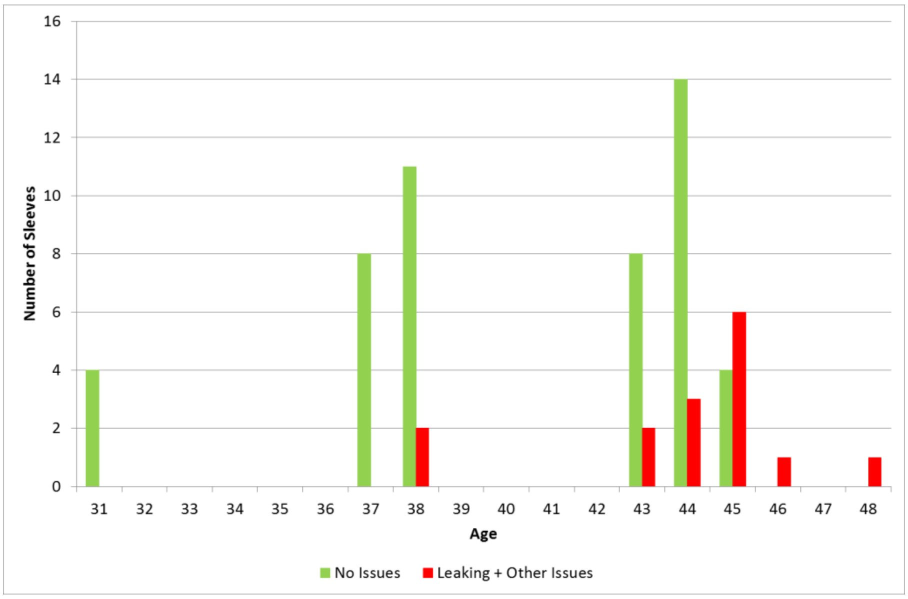

Figure 9 Assessment of Sleeve Maintenance Data to Estimate the Age at the Mid-Point of HI2 Health Index.

The PoF predictions using the model based on the above data are compared to predictions based on the EoL at age 60 years in Figure 10.

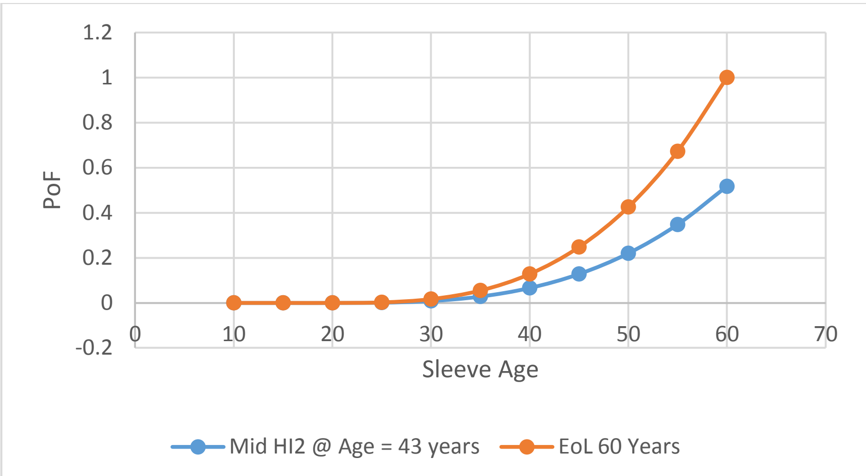

Figure 10 – N_2 Sleeve PoF Predictions Assuming Mid-Point of HI2 at Age 43 years and EoL at Age 60 Years

The results indicate that the PoF predicted based on the EoL of 60 years increases at a faster rate than the PoF predicted assuming a mid HI2 Health Index at 43 years.

Based on the above studies, the model based on the EoL of 60 years was selected for application. NGN have considered the predictions obtained using this model, and have commented that the percentages of HI3 and HI4 are higher than expected. Following further assessment, this model may be replaced with the model assuming a mid-point of HI2 Health Index at 43 years.

4.3 Non-N_2 Sleeves Health Index Predictions

The sleeve PoF model requires the age of the sleeve, the coating type, the sleeve material type, the end sleeve type, the annual fill material and the sleeve length. A leakage factor based on a simplification of the logic used in the UKOPA sleeve risk ranking model is calculated, and normalised against a typical average value, determined from a data for a population of 565 sleeves provided by NGN. The model assumes an EoL of 60 years. Predictions have been made using data from the UKOPA sleeve risk ranking model.

The results obtained for the GDNs are given in Table 9:

GDN	HI1	HI2	HI3	HI4	HI5
NGN	0	36%	31%	24%	9%
SGN	2%	34%	26%	23%	15%
UKD	1%	37%	18%	18%	26%
WWU	7%	41%	21%	25%	6%

Table 9 – Percentage of Non-N_2 Sleeves in Health Index Categories

4.4 N_2 Sleeves Health Index Predictions

The sleeve PoF model requires the age of the sleeve, the coating type, the sleeve material type, the end sleeve type, the annual fill material and the sleeve length. A leakage factor based on a simplification of the logic used in the UKOPA sleeve risk ranking model is calculated, and normalised against a typical average value, determined from a data for a population of 565 sleeves provided by NGN. The model assumes an EoL of 60 years. Predictions have been made using data from the UKOPA sleeve risk ranking model.

The results obtained for the GDNs are given in Table 10.

GDN	HI1	HI2	HI3	HI4	HI5
NGN	0	60%	33%	5%	5%
SGN	2%	35%	30%	26%	7%
UKD	0	23%	40%	23%	14%
WWU	8%	63%	20%	9%	0

Table 10 – Percentage of N_2 Sleeves in Health Index Categories

5 Prediction for Health Index for Crossings

5.1 PoF Model for Above Ground Crossings

The simple PoF model described in Section 2.3 was used to predict the PoF vs. age for above ground crossings, assuming a fixed EoL of 60 years. This model was used to provide a base line PoF vs. age prediction.

Little data is available for above ground crossings. GDNs were requested to indicate the number of above ground crossings on specific pipelines, and also the length of the crossings. The primary factor which is most likely to affect the condition of above ground crossings is at the soil/atmosphere interface. This will be affected by location rather than crossing length. Consequently, the length has not been incorporated in the model at this stage. The predicted PoF vs. age obtained using the simple basic model is shown in Figure 11.

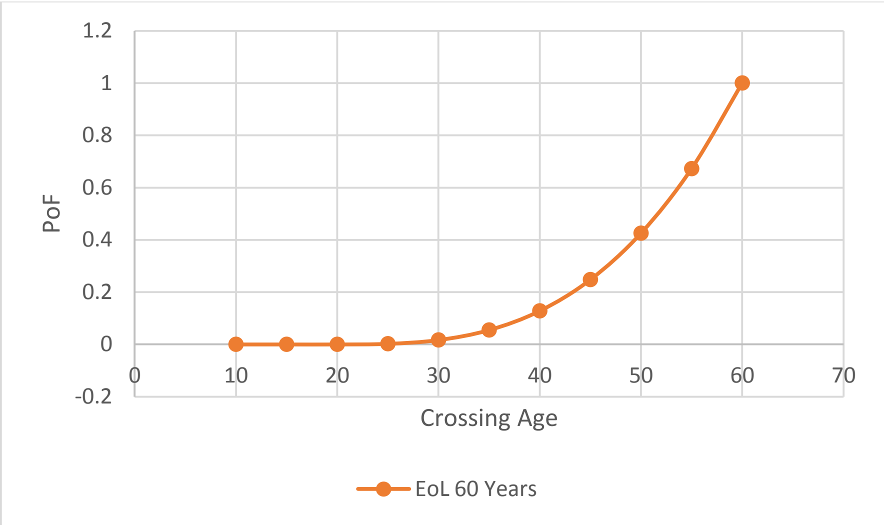

Figure 11 – Above Ground Crossing PoF vs. Age Predictions

5.2 Above Ground Crossings Health Index Predictions

The results obtained for the GDNs are given in Table 11.

GDN	HI1	HI2	HI3	HI4	HI5
NGN	3%	17%	41%	39%	0
SGN	%	%	%	%	%
UKD	%	8%	20%	60%	12%
WWU	7%	2%	20%	37%	34%

Table 11 – Percentage of Above Ground Crossings in Health Index Categories

5.3 PoF Model for River Crossings

The integrity and condition of a pipeline river crossings is equivalent to that of the pipeline on which it is located, providing the condition of the river bed and banks is fit for purpose. The condition of the river crossing and the river bed and banks is confirmed through regular underwater surveys, which are scheduled according to i) whether the water course is major or minor, and in the case of major water courses, whether these are tidal and/or navigable, and ii) the depth of cover of the crossing.

Where any remedial work identified by the underwater survey has been carried out, and/or the results of surveys and local inspections have confirmed that the condition of the river crossing is fit for purpose, the PoF of a river crossing is equivalent to that of the pipeline on which it is located.

A data checking exercise is required in order to identify river crossings on OLI1 and OLI4 pipelines, and to subsequently include these crossings in the OLI1 and OLI4 pipeline PoF models. Until this exercise is complete, the simple PoF model described in Section 2.3 is being used to predict the PoF vs. age for river crossings, assuming a fixed EoL of 60 years, as has been applied to above ground crossings. This model was used to provide a cautious base line PoF vs. age prediction for river crossings.

The primary factor which is most likely to affect the condition of river crossings is the water flowrate and the potential for river flooding. This will be affected by location rather than crossing length. Consequently, the length of the river crossing has not been incorporated in the model at this stage. The predicted PoF vs. age obtained using the simple basic model is as shown for above ground crossings in Figure 11.

5.4 River Crossings Health Index Predictions

The results obtained using the simple PoF for the GDNs are given in Table 12.

GDN	HI1	HI2	HI3	HI4	HI5
NGN	10%	44%	36%	10%	0
SGN	40%	12%	10%	25%	13%
UKD	8%	41%	18%	31%	2%
WWU	79%	9%	6%	6%	0

Table 12 – Percentage of River Crossings in Health Index Categories

6 Conclusions

A simple probability of failure vs. age model has been developed for block valves, non-nitrogen and nitrogen sleeves, and above ground crossings. The model combines a constant PoF up until the asset age of 20 years, followed by an increasing PoF with age calculated using a simple cubic relationship.

This model is a simplification of the relationship recommended by EA Technology in work carried out for WWU, but the form of the equation is derived by making simple assumptions regarding the PoF at a specific age or EoL of the asset.

The PoF of a river crossing which has been confirmed to be fit for purpose by underwater survey results is equivalent to that of the pipeline on which it is located. A data checking exercise is required in order to identify river crossings on OLI1 and OLI4 pipelines, and to subsequently include these crossings in the OLI1 and OLI4 pipeline PoF models. Until this exercise is complete, the simple PoF model has been used to predict the PoF vs. age for river crossings.

The predictions of PoF with age are translated into a Health Index value using the PoF vs. HI relationship agreed by the GDNs, given in Table 2.

The models developed allow to use condition data obtained through intervention actions which will allow the PoF for a specific age to be redefined.

The models have been populated where possible with asset data and forwarded to the GDNs. The results can be tuned or modified using relevant factors if required.

J V Haswell	**C Lyons**
Principal Consultant	**Senior Consultant**

7 References

1 Reliability Centred Maintenance. John Moubray. 1991. ISBN 0 7506 02309.

2 Condition Baaed Risk Management: Trial Project for District Governors. D Miller, D Hughes EA Technology Report No 76100 September 2010

3 Ranking Scheme for Prioritising the Inspection of Pipeline Sleeves. D G Walker Report Number 13065 August 2013.

Appendix 1 - Proposed Definition of Intervention Process required to Reassign Block Valve Health Index

The intervention process required to demonstrate that a block valve with a predicted HI4 or HI5 is in adequate condition to reassign the health index to HI2 is proposed as follows:

Stage 1 – Review Records

Review records (functional check records, maintenance records)

Identify any valves which do not have full functional check records and schedule checks within 12 months.

Identify any valves which have undergone major maintenance (see Stage 3 below) within the previous 10 years, confirm successful functional checks have been carried out within the previous 12 months, reassign valve health index to HI2 at the date at which major maintenance was completed.

Identify valves for Stage 2 additional checks and visual inspections.

Stage 2 – Carry Out Additional Checks and Visual Inspections

Carry out the following additional checks:

1. Seat leakage
2. Stem leakage
3. Valve operation
4. Operator stop setting
5. Condition of small bore vent and lubrication pipework
6. Sealant fitting leakage

Complete routine maintenance requirements.

Identify any requirements for major maintenance (Stage 3).

Clean and lubricate the valve.

Carry out visual inspection to identify corrosion on the valve body, sealant and lubrication lines, and the condition of the valve pit and civil works. Complete remedial works or schedule completion under Stage 3 if required.

If no additional maintenance under Stage 3 is required, reassign valve health index to HI2.

Stage 3 – Major Maintenance

Complete major maintenance required as identified in Stage 2.

1. Major maintenance includes the following activities:
2. Actuator repairs/replacement
3. Gear box repairs/replacement
4. Replacement of small bore vent and lubrication pipework
5. Stem extension repairs
6. Civil work repairs

On completion of major maintenance, reassign block valve health index to HI2.

Stage 4 – Document Results and Draw Conclusions

Document results to justify reassignment of health index HI2.

Review results to assess whether the end of life assumption (60 years) applied in the valve PoF model should be revised.

Appendix 2 - Proposed Definition of Intervention Process required to Reassign Non-Nitrogen Sleeve Health Index

The intervention process required to demonstrate that a non-nitrogen sleeve with a predicted HI4 or HI5 is in adequate condition to reassign the health index to HI2 is proposed as follows:

Stage 1 – Review Records

Review records (pipeline inspection and maintenance records, any non-nitrogen sleeve assessment records)

Identify any non-nitrogen sleeves which have not been subject to detailed review in accordance with the UKOPA sleeve model requirements, and identify any non-nitrogen sleeves with health indices of HI4/HI5 for review within 12 months.

Identify any sleeves which have undergone detailed assessment in accordance with the UKOPA sleeve model requirements (see Stage 3 below) within the previous 5 years. If the assessment has as confirmed the condition is acceptable, ensure data used in the non-nitrogen sleeve PoF model is correct and reassign the non-nitrogen sleeve health index to HI2 at the date at which the assessment was completed.

Identify sleeves for Stage 2 assessment. Note, assessment of a sample of sleeves with similar or worst case parameters on the same pipeline may be justified and documented.

Stage 2 – Non-Nitrogen Sleeve Assessment

Carry out the following assessment checks:

1. OLI1 pipelines - carrier pipeline ILI data
2. CIPS/Pearson/DCVG survey results, and for OLI4 pipelines, assessment of ILI data for equivalent sleeve/pipeline configuration
3. Assessment of coating degradation
4. Evidence of metal to metal contact
5. CP connections and readings
6. Assessment of potential for water or air in annulus – i) end seal design, ii) end seal degradation, iii) annular fill, iv) ground conditions

Complete routine maintenance requirements.

Based on the results of the assessment checks and routine maintenance, identify any requirements for remedial work (Stage 3).

Complete remedial works or schedule completion under Stage 3 if required.

If no additional remedial work under Stage 3 is required, reassign non-nitrogen sleeve health index to HI2.

Stage 3 – Remedial Work

Complete any remedial work required as identified in Stage 2. This may include:

1. Recoating of sleeve
2. Replacement of small bore connections if appropriate
3. Extracting a sample of the annual fill material to identify water or air ingress
4. Replacement of end seals and refilling of annulus
5. Removal of sleeve and completion of appropriate remedial work on the carrier pipe (ie recoating, relaying in heavy wall)

On completion of required remedial work, reassign the non-nitrogen sleeve health index to HI2.

Stage 4 – Document Results and Draw Conclusions

Document results to justify reassignment of health index HI2.

Review results to assess whether the end of life assumption (60 years) applied in the non-nitrogen sleeve PoF model should be revised.

Appendix 3 - Proposed Definition of Intervention Process required to Reassign Nitrogen Sleeve Health Index

The intervention process required to demonstrate that a nitrogen sleeve with a predicted HI4 or HI5 is in adequate condition to reassign the health index to HI2 is proposed as follows:

Stage 1 – Review Records

Review records (nitrogen sleeve pressure checks, pipeline inspection and maintenance records, any nitrogen sleeve assessment records)

Identify any nitrogen sleeves which have not been subject to detailed review in accordance with the UKOPA sleeve model requirements, and schedule any nitrogen sleeves with health indices of HI4/HI5 for review within 12 months.

Identify any nitrogen sleeves which have undergone detailed assessment in accordance with the UKOPA sleeve model requirements (see Stage 3 below) within the previous 5 years. If the assessment has as confirmed the condition is acceptable, ensure data used in the nitrogen sleeve PoF model is correct and reassign the nitrogen sleeve health index to HI2 at the date at which the assessment was completed.

Identify sleeves for Stage 2 assessment. Note, assessment of a sample of nitrogen sleeves with similar or worst case parameters on the same pipeline may be justified and documented.

Stage 2 – Nitrogen Sleeve Assessment

Carry out the following assessment checks:

1. OLI1 pipelines - carrier pipeline ILI data
2. CIPS/Pearson/DCVG survey results, and for OLI4 pipelines, assessment of ILI data for equivalent sleeve/pipeline configuration
3. CP connections sand readings
4. Assessment of nitrogen sleeve pressure records
5. Assessment of coating degradation
6. Assessment of fill/vent line condition

Complete routine maintenance requirements.

Based on the results of the assessment checks and routine maintenance, identify any requirements for remedial work (Stage 3).

Complete remedial works or schedule completion under Stage 3 if required.

If no additional remedial work under Stage 3 is required, reassign nitrogen sleeve health index to HI2.

Stage 3 – Remedial Work

Complete any remedial work required as identified in Stage 2. This may include:

1. Recoating of sleeve
2. Replacement of small bore fill/vent connections
3. Extracting a sample of gas from the annulus to identify the oxygen and water content
4. For nitrogen sleeves which do not have forged end seals, replacement of end seals

On completion of required remedial work, reassign the nitrogen sleeve health index to HI2.

Stage 4 – Document Results and Draw Conclusions

Document results to justify reassignment of health index HI2.

Review results to assess whether the end of life assumption (60 years) applied in the nitrogen sleeve PoF model should be revised.

Appendix 4 - Proposed Definition of Intervention Process required to Reassign Above Ground Crossing Health Index

The intervention process required to demonstrate that an above ground crossing with a predicted HI4 or HI5 is in adequate condition to reassign the health index to HI2 is proposed as follows:

Stage 1 – Review Records

Review records (visual inspection of crossing, pipeline inspection and maintenance records, any crossing maintenance records including assessment and repair of corrosion at supports and the soil/air interface).

Identify any above ground crossings which have not been subject to inspection and schedule any above ground crossings with health indices of HI4/HI5 for inspection within 12 months.

Identify any above ground crossings which have undergone detailed condition assessment (see Stage 3 below) within the previous 5 years. If the assessment has as confirmed the condition is acceptable, reassign the above ground crossing health index to HI2 at the date at which the assessment was completed.

Identify above ground crossings for Stage 2 assessment.

Stage 2 – Above Ground Crossing Condition Assessment

Carry out the following condition assessment checks:

1. Paint/coating condition and evidence of surface corrosion
2. Check for corrosion at supports
3. Check for corrosion at the soil/air interface
4. Evidence of vandalism or external interference damage
5. Condition of supports and access guards
6. Condition of expansion joints if appropriate

Based on the results of the condition assessment checks, identify any requirements for remedial work (Stage 3).

Complete remedial works or schedule completion under Stage 3 if required.

If no additional remedial work under Stage 3 is required, reassign above ground crossing health index to HI2.

Stage 3 – Remedial Work

Complete any remedial work required as identified in Stage 2. This may include:

5. Painting and/or coating repairs
6. Repair/replacement of supports and access guards
7. Repair of corrosion and coating at the soil/air interface
8. Repair of expansion joints if appropriate

On completion of required remedial work, reassign the above ground crossing health index to HI2.

Stage 4 – Document Results and Draw Conclusions

Document results to justify reassignment of health index HI2.

Review results to assess whether the end of life assumption (60 years) applied in the above ground crossing PoF model should be revised.

Appendix 5 - Proposed Definition of Intervention Process required to Reassign River Crossing Health Index

The intervention process required to demonstrate that a river crossing with a predicted HI4 or HI5 is in adequate condition to reassign the health index to HI2 is proposed as follows:

Stage 1 – Review Records

Review records (river crossing survey results, pipeline inspection and maintenance records).

Identify any river crossings with health indices of HI4/HI5. Reassign the river crossing health index to the pipeline health index (Stage 2).

Identify any river crossings which have undergone remedial/repair works, and reassign the river crossing health index to HI2 at the date at which the remedial/repair works were completed.

Identify river crossings for Stage 2 assessment.

Stage 2 – River Crossing Condition Assessment

Identify the health index of the pipeline on which the river crossing is located, and note the presence of the river crossing in the relevant OLI1 or OLI4 pipeline PoF model.

Based on the results of the underwater survey results, identify any requirements for remedial work (Stage 3).

Complete remedial works or schedule completion under Stage 3 if required.

If no additional remedial work under Stage 3 is required, the river crossing health index is equivalent to the relevant pipeline health index.

Stage 3 – Remedial Work

Complete any remedial work required as identified in Stage 2. This may include:

1. Increasing the depth of cover in the event of river bed erosion
2. Carrying out construction work to remediate/improve the condition of the river bed and banks

On completion of required remedial work, the river crossing health index is equivalent to the relevant pipeline health index.

Stage 4 – Document Results and Draw Conclusions

Document results to confirm the river crossing health index is equivalent to the pipeline health index.