Penspen Integrity
Units 7-8
St. Peter's Wharf
Newcastle upon Tyne
NE6 1TZ
United Kingdom

Telephone: +44 (0)191 238 2200
Fax: +44 (0)191 275 9786
Email: integrity.ncl@penspen.com
Website: www.penspenintegrity.com

Proceedings of the 2012 9th International Pipeline Conference
IPC2012
September 24-28, 2012, Calgary, Alberta, Canada

IPC2012-90280

USING QUANTITATIVE RISK ASSESSMENT TO JUSTIFY LOCATION CLASS CHANGES: CASE STUDY

Paul Rumney
Penspen Ltd.
Newcastle upon Tyne, UK
p.rumney@penspen.com

Graham Goodfellow
Penspen Ltd.
Newcastle upon Tyne, UK
g.goodfellow@penspen.com

ABSTRACT

Expansion of existing residential and commercial areas, or the construction of new developments in the vicinity of high pressure gas transmission pipelines can change a Location Class 1 into a Class 2 or Class 3 location. Operators are left with a pipeline that no longer meets the requirements of its design code.

Reducing the maximum allowable operating pressure of a pipeline, or re-routing it away from the population, can meet the requirements of a design code, such as CSA Z662 or ASME B31.8, but such options have both high costs and significant operational difficulties.

Quantitative risk assessment has been employed successfully for many years, by pipeline operators, to determine risk based land use planning zones, or to justify code infringements caused by new developments. By calculating the risk to a specific population from a pipeline, and comparing it with suitable acceptability criteria, a pipeline may be shown to contribute no more risk to a population than other pipelines operating entirely in accordance with the design codes.

Risks may be demonstrated to be ‘as low as reasonably practicable’, through the use of cost benefit analysis, without additional mitigation, allowing precious pipeline maintenance funds to be spent most effectively in areas where they will have the highest impact on risk.

This paper shows how quantitative risk assessment may be used to justify continued safe operation of a pipeline at its original operating stress following a change of class designation, illustrated with a case study from Western Europe.

INTRODUCTION

Wherever possible, major accident hazard pipelines (MAHP) are routed to avoid areas of dense population. Accordingly, most high pressure natural gas transmission pipelines are located in open countryside, far from any major cities or towns. These areas would generally be classified by design codes such as ASME B31.8 [1] or CSA Z662 [2] as Location Class 1, containing 10 or fewer habitable buildings per 1 mile (1.6 km) zone.

The construction of new housing developments or commercial and industrial centres, can lead to areas which had originally been designated as Class 1, being reclassified as Class 2 or Class 3 if the level of additional development exceeds that which is allowed for by the original design.

Codes and Standards

ASME B31.8 allows for an increase in the number of dwellings within each zone, beyond the limit defined by the initial design requirements, before the location must be reclassified. In the case of a pipeline originally designed for a Class 1 area, a maximum of 25 habitable buildings is permissible before the location must be reclassified as Class 2. More than 65 habitable buildings would then necessitate the change to a Class 3 location.

In such cases where the location has been reclassified, the only courses of action which are currently permissible are: to downrate the maximum operating pressure of the pipeline; replace the affected section with low stress pipe; or, re-route it away from the population. All of these options would incur significant cost to the pipeline operator, either through lost transportation revenue or additional construction.

Location classes defined by CSA Z662 follow similar boundary definitions and development level limits to ASME B31.8, except that an increase in the number of dwellings beyond the original limit as defined by the initial design requirements is not permitted. However, where a change of location class occurs, CSA Z662 allows for an engineering assessment of the location to be performed in order to determine whether the pipeline in its current state is acceptable for continued operation at the original maximum operating pressure (MOP). CSA Z662 allows reliability based design and assessment (RBDA) as a suitable method, as outlined in Annex O, but also provides guidance on risk assessment in Annex B.

In the UK, high pressure gas transmission pipelines are designed using IGEM/TD/1 [3], which defines locations as either Type R, Type S or Type T. For determining the number of habitable buildings surrounding the pipeline, IGEM/TD/1 defines a corridor width based on a building proximity distance which is defined according to the MOP and diameter of the pipeline. The density of people and prevalence of certain types of construction within this corridor then determines the associated location type. A density of less than or equal to 2.5 persons per hectare corresponds to a rural Type R area. Above 2.5 persons per hectare and with extensive developments including shops and schools would be considered to be Type S. Central areas of towns and cities with numerous multi-storey buildings and dense traffic would be classified as Type T; however, high pressure gas transmission pipelines are not permitted by IGEM/TD/1 in such locations.

The requirement in IGEM/TD/1 for four yearly MOP affirmation of pipelines, by way of pipeline route survey and data auditing, can lead to the discovery of numerous infringements in a densely populated country like the UK. These are generally in the form of increased population density beyond the area types allowable limit and also construction within the minimum building proximity distance for the pipeline (an additional proximity based restriction). In such cases, IGEM/TD/1 requires that these infringements are subject to a safety evaluation to assess the risks and to determine whether or not remedial action needs to be taken.

Quantitative risk assessment (QRA) of code infringements is a safety evaluation method accepted by the UK Health and Safety Executive. This allows the probability (frequency) of a hazardous event to be considered in combination with the potential consequences.

Following on from incidents such as that in San Bruno, California in September 2010 [4], there is increased drive in the industry for review of locations with extensive development in the vicinity of high pressure gas pipelines. The use of QRA to assess such locations can allow limited resources to be spent in the areas where they are needed most, and where they will provide the greatest benefit.

QUANTITATIVE RISK ASSESSMENT

The generally accepted methodology [5] [6] [7] for performing quantitative risk assessment of pipelines is outlined in Figure 1.

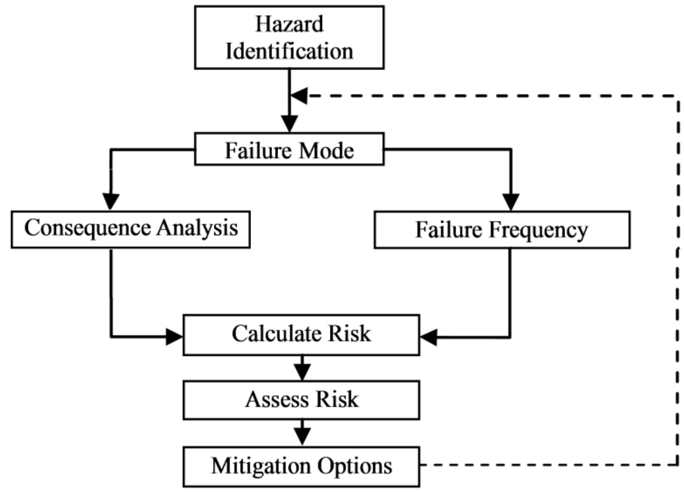

Figure 1: Quantitative Risk Assessment Methodology

The various steps involved have been analysed and defined on many occasions previously and are outlined briefly below.

Hazard Identification

Determining all the potential hazards to a pipeline is critical if a realistic determination of the potential failure frequency is to be made. The nine main causes of pipeline failure according to ASME B31.8S [8] are:

- External corrosion;
- Internal corrosion;
- Stress corrosion cracking (SCC);
- Manufacturing defects;
- Welding and fabrication defects;
- Equipment failure;
- External interference damage;
- Incorrect operations; and,
- Weather-related and outside forces.

Typically, only those hazards which cannot be fully controlled by the pipeline operator’s inspection, maintenance and repair policy are included in QRA; usually external interference and weather-related and outside forces (e.g. ground movement).

Other hazards, such as corrosion and manufacturing and fabrication defects, can be controlled to prevent failure with appropriate operating, inspection and maintenance procedures and are often not included in the analysis of failure frequency.

Pipeline Failure Frequency

Historical data on pipeline failures and in some cases incidents of damage not leading to failure, is collected by several groups around the world including the US Department of Transports Pipeline and Hazardous Materials Safety Administration (PHMSA) [9], the National Energy Board of Canada (NEB) [10], the European Gas pipeline Incidents data Group (EGIG) [11], the Conservation of Clean Air and Water in Europe (CONCAWE) [12] and the United Kingdom Onshore Pipeline Association (UKOPA) [13].

	EGIG	UKOPA
Period	1970 - 2010	1962 – 2010
Pipeline Length (km)	135,211	22,370
Exposure (km years)	3,550,000	785,385
No. of Incidents	1,249	184
Incident Frequency (per 1000 km year)	0.351	0.234

Table 1: EGIG and UKOPA Incident Statistics

Pipeline failures are rare [14] which makes selecting a suitable historical failure frequency for a particular pipeline from this data difficult, and therefore it is more usual to predict failure frequencies for a set of specific pipeline parameters. Pipeline hit rates[1] have been determined from historical data [15] and can be combined with distributions of defect shape and industry standard defect failure equations [16] [17] [18] [19] to predict leak and rupture failure frequencies due to external interference.

Consequence Assessment

Consequence assessment includes analysis of the gas outflow and dispersion, ignition probability, thermal radiation and the radiation effects on people and property. This has been covered previously in many papers [20] [21] [22] [23] [24] [25].

Guidance supplements to the UK codes, eg IGEM/TD/2 [5], suggest several complex modeling scenarios which should be taken into consideration when performing a consequence assessment. This includes accurate modeling of the boundary conditions for the pipeline system, such as the location and operability of valves and compressors.

Transient outflow from pipelines as the inventory blows down is required, resulting in a variation in the thermal radiation levels with time after failure. Inclusion of the effect of available shelter must also be considered along with the ability of any population present to try and escape. This includes allowing population to move between shelters as they become unavailable.

Individual Risk

Though more applicable to point like sources of risk such as refineries or other chemical plant, the individual risk for a pipeline is often still presented as an indication of the general risk level presented by the pipeline. Individual risk criteria presented by the UK HSE defines an acceptable level of risk as a one in a million chance of fatality per year to a member of the public. Above a one in ten thousand chance is unacceptable, with the region between being the tolerable if as low as reasonably practicable, or 'ALARP' region, Figure 2. Risk levels within this region must be demonstrated to be ALARP.

[1] The number of times a pipeline might expect to be impacted per km year.

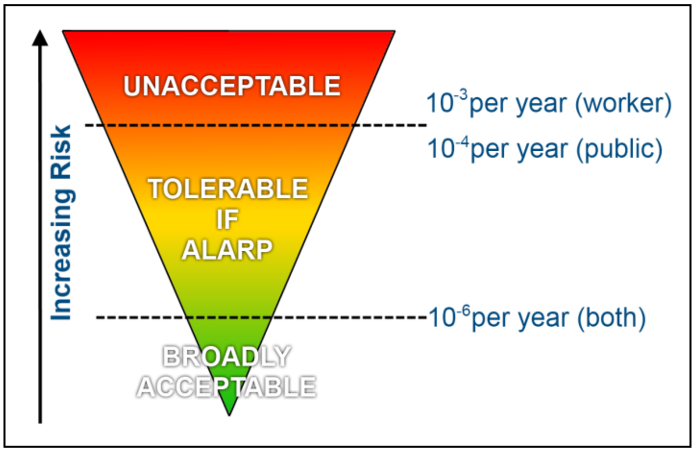

Figure 2: UK HSE Individual Risk Criteria

Societal Risk

Due to the potentially larger number of people who could be affected by a pipeline failure, societal risk is considered a more appropriate measure for the risk presented by a pipeline. IGEM/TD/1 includes societal risk acceptability criteria presented on an FN chart, (showing the frequency F, of N or more casualties versus the number of casualties, N), the criteria being based on an assessment of many pipelines designed and operated to previous editions of IGEM/TD/1. The region inside the envelope is defined as the broadly acceptable region, with the area outside the envelope being the tolerable if ALARP region.

Mitigation and Cost Benefit Analysis

Where assessment of societal risk indicates that risk levels lie above the IGEM/TD/1 acceptability criteria in the tolerable if ALARP region, it is necessary to demonstrate that the risks are acceptable by determining the reduction in risk which could be achieved with the implementation of risk mitigation measures and comparing this with the cost involved.

Common forms of risk mitigation for pipelines include the installation of concrete slabs and warning tape above the pipeline, or relaying the pipeline in thicker wall pipe. These measures reduce the risk primarily by decreasing the failure frequency due to third party interaction.

CASE STUDY – WESTERN EUROPE

A recent application of quantitative risk assessment at a location in Western Europe involved a nursing home which had been newly constructed on open land, in close proximity to a high pressure natural gas pipeline. The pipeline at this location had previously been classified as Type R with a design factor exceeding 0.3, approximately equivalent to Location Class 1 or 2 [26] in ASME B31.8 or CSA Z662. Following construction of the nursing home, approximately 460 m of the pipeline was reclassified as Type S, generally equivalent to Location Class 3. Pipelines in a Type S area are required to have a design factor not exceeding 0.3, or 0.5 where the pipe wall thickness is greater than or equal to 19.05 mm, according to the design code IGEM/TD/1.

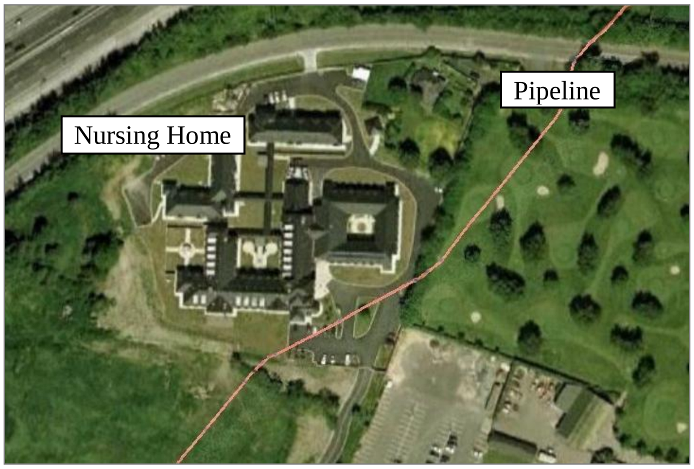

Figure 3: Aerial Image of Assessment Location

The infringement of the design code required that a QRA be performed to determine whether the risk levels were ALARP and whether the pipeline was suitable to continue operating at its MOP, in its current state or the pipeline relaid with suitable wall thickness.

Location

The pipeline is a high pressure natural gas transmission line commissioned more than 20 years prior to the construction of the nursing home. The pipeline parameters are summarised in Table 2.

Parameter	Value
Site	Nursing Home
Diameter (mm)	457.2
Material Grade	API 5L X60
SMYS (N/mm^2)	415
Maximum Operating Pressure (barg)	70
Standard Pipe (mm)	9.5
Design Factor	0.46
Depth of Cover (m)	1.83 – 2.2

Table 2: Summary of Pipeline Parameters

The nursing/convalescence home is a 2 storey building of brick construction with a further retirement home apartment block located on the same site at the northern end of the complex. In total, the entire complex contained a maximum of 124 residents, all of whom were considered as vulnerable[2] population for the purposes of the assessment. In addition there were a further 64 staff and visitors present during the day, with 44 present at night. All additional persons were taken as standard[3] population.

At its nearest point, the nursing home building lay within approximately 7 m of the pipeline.

Hazard Identification

The operators of the pipeline had a formal pipeline integrity management plan in place to reduce the likelihood of external corrosion, control fatigue and minimize the consequence of ground movement.

The presence of good quality, factory-applied external coatings, impressed current cathodic protection systems and regular inspection all minimise the chance of external corrosion.

Results data from previous in-line inspections (ILI) indicated no ongoing corrosion: any identified defects determined to be unacceptable would be investigated and repaired.

The pipeline route followed stable, level ground which was known to have no history of susceptibility to ground movement.

All the available information, including material data and the operational duty of the pipeline, supported the conclusion that external interference was the only applicable uncontrolled hazard for this pipeline.

Pipeline Failure Frequency

The only applicable hazard to this pipeline was failure due to third party interference. Therefore, the failure frequency was determined using Penspen's in-house predictive model, PI-FAIL. PI-FAIL uses direct numerical integration of the probability functions to predict the leak[4] and rupture[5] failure frequency from third party damage for a given set of pipeline operating parameters, with modification factors for the effect of depth of cover, location class and protective measures. [27]. The predicted baseline failure frequencies for 1.1 m depth of cover in a Type S area are given in Table 3.

Failure Mode	Failure Frequency per million km years
Leak	92.27
Rupture	34.24

Table 3: Predicted Pipeline Failure Frequencies

Gas Outflow

Based on the layout of the pipeline system, it was determined that pressure could be maintained from a point approximately

[2] Vulnerable or sensitive, refers to anyone who is expected to become a fatality after receiving a dose equal to or greater than 1050 thermal dose units (tdu), sometimes referred to as the 1% lethality dose, such as children, the sick or elderly.

[3] Standard refers to anyone who would be expected to become a fatality after receiving a dose equal to or greater than 1800 tdu.

[4] A puncture or hole with a diameter equivalent to the maximum stable through wall defect [28] [29].

[5] A full bore rupture of the pipeline where the hole diameter is equal to or greater than the diameter of the pipeline.

20 km upstream of the assessment location. Due to the absence of any remotely operable valves, it was also conservatively determined that the entire inventory from the remaining downstream section of the pipeline system would be available to blowdown. The resulting release from a full bore rupture and a 20 mm diameter leak, was calculated using the University College London (UCL) PipeTech [30] computational fluid dynamic simulator. PipeTech is in use by many major oil and gas companies around the world and is also used by the UK Health & Safety Executive (HSE) in determining its advice to local planning authorities on control of land-use in the vicinity of major accident hazard pipelines.

The variation of mass release rate with time after failure is shown in Figure 4 for a full bore rupture[5] of the pipeline. The release is the total of the mass released from both the upstream and downstream ends of the pipeline.

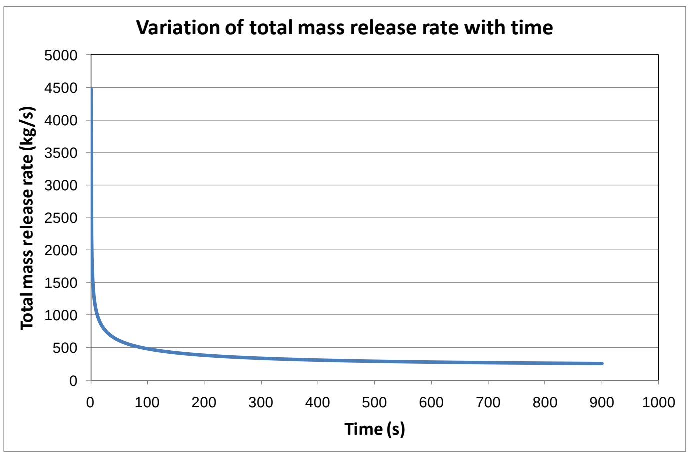

Figure 4: Variation of Mass Release Rate with Time Following Full Bore Rupture

The transient outflow was calculated assuming that the pipeline was shut in at the MOP prior to failure. Although unlikely for most operational gas transmission pipelines, this represents a standard assumption in QRAs in the UK which represents the worst case and allows comparison of the calculated risk levels with published UK risk criteria. The time limit for all incidents is assumed to be 900 seconds from the release of gas, after which the fire is likely to have stabilised to a pseudo steady state as the pipeline unpacks. Any persons who do not receive a fatal dose of thermal radiation in 900 seconds are assumed to have survived the incident by finding safe shelter or reaching a point where the thermal radiation level is equivalent to strong sunlight.

The outflow from the 20 mm diameter leak was calculated to be just above 3 kg/s and remained approximately steady for the duration of the assessment.

No consideration was given to the effect of any valve closures since typically, the safety consequences of a release will have been realised by the time adjacent valves can be closed. Obviously, valve spacing and closure time will affect the time taken to bring the pipeline fire under control and this will affect public perception of any incident [31].

Ignition Probability

The ignition probabilities for a full bore rupture and a 20 mm diameter leak were calculated using the IGEM/TD/2 recommended model and are summarised in Table 4.

Failure Mode	Ignition Probability (%)
Leak (20 mm diameter)	6
Rupture	26

Table 4: Summary of Calculated Ignition Probabilities

As recommended by guidelines [5], it was assumed that half of all releases which ignited did so immediately and half were delayed by 30 seconds.

Thermal Radiation

Using the gas jet fire model in Shell FRED [32], the incident thermal radiation values over a range of distances from the pipeline and for a range of gas release rates, corresponding approximately to the release curve shown in Figure 4, were calculated and are displayed graphically in Figure 5.

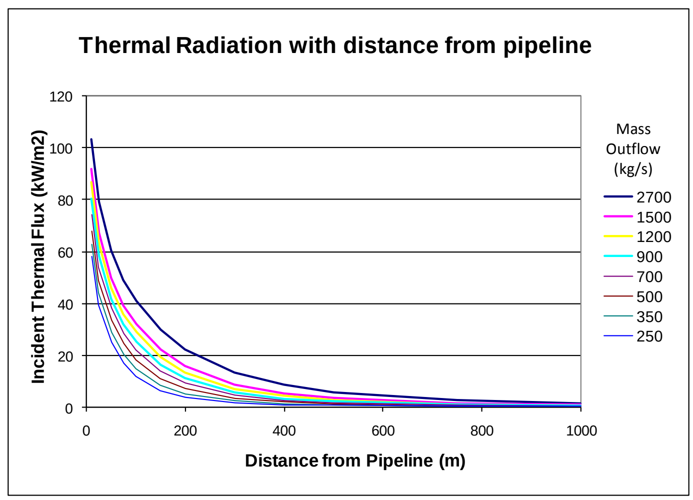

Figure 5: Variation of Incident Thermal Radiation with Outflow and Distance from Pipeline

Risk Assessment Model

The determination of risk levels was performed using Penspen's in-house risk assessment software package PI-RISK. All outflow and thermal radiation data added to the model enable the calculation of the hazard distances though integration of thermal dose through time and distance from the pipeline for escaping population and the calculation of thermal radiation effects.

PI-RISK contains a coordinate-enabled graphical function to allow a map or aerial image of the assessment location to be built into the model. The precise location, depth and specification of the pipeline and all the population can then be added along with any shelter which may be present.

The daily movement of population is modeled to account for people who may only be present during certain times of the day and the percentage of time spent outdoors can be specified. Each population point can be assigned as standard or vulnerable, altering the speed at which each person is expected to try and escape along with the maximum thermal radiation dose that can be tolerated.

The risk from all incidents, i.e. immediate and delayed ignited ruptures and leaks, that may affect the populated areas as modeled are combined to calculate both the societal risk for the populated areas and the risk to a permanently resident individual, along a specific transect.

Hazard Distances

The time at which the piloted ignition of wood occurs was calculated using PI-RISK. Any buildings beyond the distance to the piloted ignition of wood after 900 seconds are assumed not to burn down, defining a building burning distance. Escape distances for standard and vulnerable populations were calculated, defining the minimum distance a person outdoors must be from an ignited full bore rupture of the pipeline if they are to survive without shelter. These are not safe distances but are distances beyond which a person would be expected to survive if they were to start moving away from the failure location, at a speed of 2.5 m/s for standard populations, or 1 m/s for vulnerable populations.

For the nursing home case, it was additionally assumed that 10% of the inhabitants would not be able to be evacuated. The results are summarised in Table 5.

Hazard Distance	Ignition Type	
	Immediate	Delayed
Building Burning (m)	115	99
Escape (Standard) (m)	190	170
Escape (Vulnerable) (m)	340	330

Table 5: Summary of Predicted Hazard Distances

Please note that the building burning distance can be considered to be analogous with the ASME B31.8S potential impact radius.

Individual Risk

The risk to an individual of becoming a fatality per year is calculated for a transect at 90° to the pipeline and is for a theoretical person resident 100% of the time at varying distances away from the pipeline. It is assumed that 10% of the time is spent outside. Peak individual risk levels for standard populations were calculated to be 1.0×10^{-7} and for vulnerable populations were 1.3×10^{-7}. The individual risk transects are shown in Figure 6 and include the UK HSE [5] individual risk criteria which defines the boundary between broadly acceptable risk and the ALARP region.

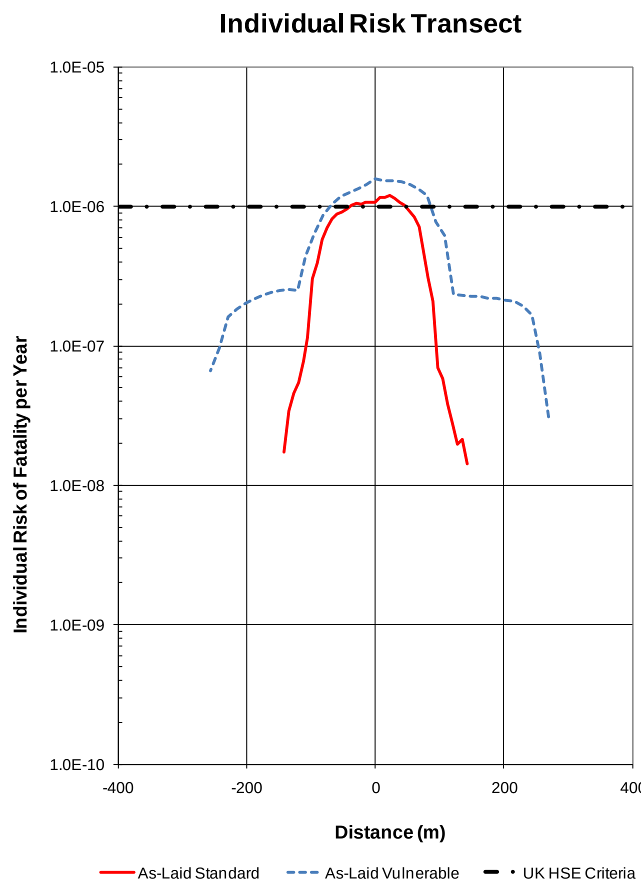

Figure 6: Individual Risk Transects for the Nursing Home

Societal Risk

Societal risk calculations were performed using an interaction length[6] of 540 m. The FN curve is shown in Figure 7 along with the IGEM/TD/1 Societal Risk Criteria. The curve can be seen to extend just outside the IGEM/TD/1 envelope, and therefore cost benefit analysis has been performed to determine whether the risks associated with the pipeline are as low as reasonably practicable.

Please note that the IGEM/TD/1 societal risk criteria has been derived from the analysis of many years of successful operation to IGEM/TD/1 in the UK and as such describes the boundary between the broadly acceptable and tolerable if ALARP regions. The upper limit of the ALARP region has not been defined by IGEM, however a sensible initial assumption would be a straight line with a slope of -1 and a y-intercept of 1×10^{-2} per annum.

Mitigation

In order to determine whether risk levels were ALARP, the models were re-run with two different mitigation options; the installation of concrete slabbing with warning tape and relaying

[6] The length of pipeline which could cause harm to an individual or development.

of the pipeline in thicker walled pipe. In both cases, the mitigation was assumed to run for the entire 460 m length of the Type S area at the location, as defined by the pipeline design code.

The resulting FN curves are shown in Figure 7.

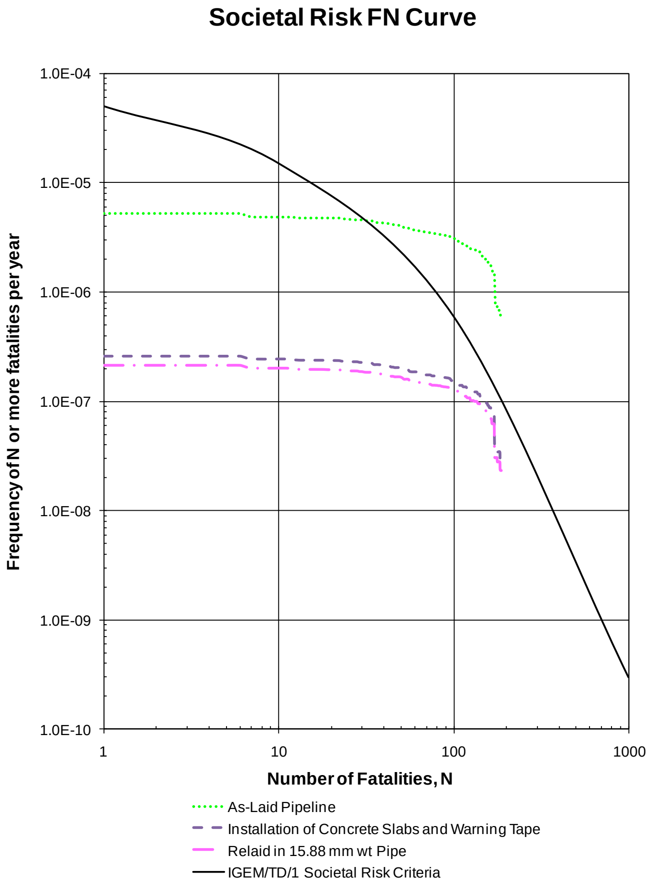

Figure 7: Societal Risk FN Curves for the Nursing Home

Both mitigation options can be seen to reduce the societal risk levels to within the broadly acceptable region of the IGEM/TD/1 envelope. The cost of performing these mitigation measures would be a minimum of US$330,000 for laying concrete slabbing with warning tape and US$1,380,000 for relaying the pipeline in thicker walled pipe.

Cost Benefit Analysis

Cost benefit analyses can be performed by determining a cost per casualty[7] averted (CCA) value, or cost per fatality prevented, as a result of applying some form of mitigation.

$$CCA = \frac{\$}{(\Delta EV) \cdot RL} \qquad (1.)$$

Where:

CCA = Cost per casualty averted

$\$$ = Total cost of applying some form of mitigation

ΔEV = Change in expectation value following application of mitigation

RL = Remaining operational life of the pipeline, assumed as 40 yrs.

[7] In this context, a casualty refers to a fatality.

Expectation value is a statistical expression of the predicted average number of fatalities per year.

The expectation values, calculated before and after the installation of mitigation measures, are shown in Table 6, along with the associated cost per casualty averted.

Mitigation	Original Expectation Value	Mitigated Expectation Value	Estimated Cost of Mitigation	Cost Per Casualty Averted
Slabbing	9.8×10^{-5}	4.9×10^{-6}	US$330,000	US$89 million
Relaying		4.0×10^{-6}	US$1,380,000	US$367 million

Table 6: Cost per Casualty Averted for the Nursing Home

Cost of Life

Assigning a value to human life is a controversial topic; however, in cases where compensation has been paid, such as for road traffic accidents, values in the region of several million dollars per life are quoted.

In the absence of any formal or regulatory definition of a financial value for human life, it is left to the risk assessor to assign a value based on their own judgement and experience. To deal with the uncertainties associated with frequency and consequence modeling as well as the negative public reaction to incidents, multiplying the typical compensation cost of several million dollars by a factor of ten to give a value of around US$50 million per casualty averted is a reasonable measure which has been taken.

If the CCA determined by the cost benefit analyses was below this level then it would indicate that risk levels were not as low as reasonably practicable, and mitigation measures should be employed. If the CCA is significantly above this level it indicates that the cost of installing mitigation measures is unreasonably high compared with the benefit in risk reduction produced.

ALARP Demonstration

In the example illustrated here, the cost of installing mitigation to meet the requirements of the design code has been shown to be disproportionate to the level of risk reduction which would be achieved. Therefore, risk levels for the assessed location at the current MOP and in its current state are found to be ALARP, and continued operation can be justified without any further mitigation of risk.

CONCLUSIONS

A quantitative risk assessment of a location class change on a gas pipeline in Western Europe has shown that although the location does not meet the requirements of the design code, the risk levels associated with the pipeline are as low as reasonably practicable, and the pipeline remains suitable for continued operation at its current MOP.

The benefit of using QRA for pipelines is the ability to determine the absolute level of risk posed to the public in any location by a pipeline, without relying on opinions or subjective decision making. Using the principals of cost benefit analysis and ALARP, it is possible to conclude if a pipeline is acceptable for continued operation in its current state or whether any level of mitigation is required. In this way, the resources allocated by pipeline operators to maintaining and improving their systems will be directed to the areas where they improve safety, rather than simplistically follow a code.

The methodology and tools required for performing a QRA are well-established and readily available; however, there is a need to develop and agree risk levels and values for human life. The absence of internationally recognised levels and values mean that the current QRA's will be subjective and rely on the expertise of the assessor.

ACKNOWLEDGMENTS

The authors would like to thank colleagues, past and present, for their continued contribution to the field and ongoing development of the methods involved.

The authors would also like to thank the management of Penspen Ltd. for permission to include results from in-house models PI-FAIL and PI-RISK.

REFERENCES

[1] ASME B31.8-2010, "Gas Transmission and Distribution Pipeline Systems", American Society of Mechanical Engineers, 2010.

[2] CSA Z662-11, "Oil and gas pipeline systems", Canadian Standards Association, 2011.

[3] IGEM/TD/1 Edition 5, "Steel pipelines and associated installations for high pressure gas transmission", Communication 1735, Institution of Gas Engineers & Managers, 2008.

[4] Anon, "Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010", NTSB/PAR-11/01 PB2011-916501 Accident Report, National Transportation Safety Board, August 2011.

[5] IGEM/TD/2, "Application of pipeline risk assessment to proposed developments in the vicinity of high pressure Natural Gas pipelines", Communication 1737, Institution of Gas Engineers & Managers, 2008.

[6] Muhlbauer, W. K., 2004, Pipeline Risk Management Manual. Ideas, Techniques, and Resources, Third Edition, Elsevier, USA.

[7] Acton, M.R., Baldwin, P.J., Baldwin, T.R., and Jager, E.E.R., 1998, "The Development of the PIPESAFE Risk Assessment Package for Gas Transmission Pipelines," ASME International, Proceedings of the International Pipeline Conference (IPC98), Calgary.

[8] ASME B31.8S-2010, Managing System Integrity of Gas Pipelines, American Society of Mechanical Engineers, 2010.

[9] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, (2012) *Accident Statistics,* available at http://www.phmsa.dot.gov/hazmat/library/data-stats/incidents.

[10] National Energy Board (2012), http://www.neb.gc.ca.

[11] "8th Report of the European Gas Pipeline Incident Group", EGIG 11.R.0402, December 2011.

[12] CONCAWE (2012), *Oil Pipelines, http://www.concawe.be*

[13] 8th Report of the UKOPA Fault Database Management Group, Pipeline Product Loss Incidents (1962 – 2010), UKOPA/11/0076, November 2011.

[14] Bilo, M. and Kinsman, P., 1997, "MISHAP – HSE's pipeline risk assessment methodology", Pipes & Pipelines International, pp 5-12.

[15] Lyons, C, Haswell, J.V., Hopkins, P., Ellis, R. and Jackson, N.W., 2008, "A methodology for the prediction of pipeline failure frequency due to external interference", Proceedings of IPC2008, 7th International Pipeline Conference, Calgary, Alberta, Canada.

[16] JF Kiefner et al, "Failure Stress Levels of Flaws in Pressurised Cylinders", ASTM STP 536, 1973.

[17] "Manual for Determining the Remaining Strength of Corroded Pipelines", ASME B31.G-1991, 1991.

[18] "Corroded Pipelines", DNV Recommended Practice DNV-RP-F101, Det Norske Veritas, October 2004.

[19] P Roovers et al, "EPRG methods for assessing the tolerance and resistance of pipelines to external damage", in Pipeline Technology, Volume II, edited by R Denys, 2000.

[20] MR Acton, PJ Baldwin, "Ignition Probability for High Pressure Gas Transmission Pipelines", IPC2008-64173, 7th International Pipeline Conference, Calgary, Alberta, Canada, September 29 – October 3, 2008.

[21] Cleaver, R.P., Acton, M.R. and Halford, A.R., 2006, "Modelling the Effects of Pipeline Fires and the Response of People in Large Buildings", IPC2006-10158, Proceedings of IPC2006, 6th International Pipeline Conference, September 25-29, 2006, Calgary, Alberta, Canada.

[22] Acton, M.R., Baldwin, P.J., Baldwin, T.R., and Jager, E.E.R., 1998, "The Development of the PIPESAFE Risk Assessment Package for Gas Transmission Pipelines," ASME International, Proceedings of the International Pipeline Conference (IPC98), Calgary.

[23] Cleaver, R.P., Cumber, P.S. and Genillon, P., 2001, "A model to predict the characteristics of fires following the rupture of Natural Gas transmission pipelines", Trans IChemE, 79, Part B, pp 3-12.

[24] Acton, M.R., Baldwin, T.R., and Jager, E.E.R., 2002, "Recent Developments in the Design and Application of the Pipesafe Risk Assessment Package for Gas Transmission Pipelines," IPC2002-27196, ASME

International, Proceedings of IPC'02 4th International Pipeline Conference, Calgary, Alberta, Canada.
[25] M Bilo & P Kinsmann, "Thermal radiation criteria used in pipeline risk assessment", Pipes & Pipelines International, Vol. 42, Issue 5, 1997.
[26] Goodfellow, G. and Haswell, J., 2006, "A Comparison of Inherent Risk Levels in ASME B31.8 and UK Gas Pipeline Design Codes", IPC2006-10507, Proceedings of IPC2006, 6th International Pipeline Conference, September 25-29, 2006, Calgary, Alberta, Canada.
[27] Anon, "An assessment of the measures in use for gas pipelines to mitigate against damage caused by third party activity", HSE Contract Research Report 372/2001, prepared by WS Atkins Consultants Ltd. on behalf of the Health & Safety Executive, HMSO, London, 2001.
[28] Kiefner, J.F., Maxey, W.A., Eiber, R.J. and Duffy, A.R., 1973, "Failure stress levels of flaws in pressurized cylinders", American Society for Testing and Materials STP 536, pp 461-481.
[29] Miller, A.G., 1984, "Review of Limit Loads of Structures Containing Defects", CEGB Report TPRD/B/0093/N82 Rev 1.
[30] PipeTech v35, Interglobe Ltd., 2011.
[31] Eiber, R.J., et al, "Valve Spacing Basis for Gas Transmission Pipelines", PRCI Report L51817, Pipeline Research Council International, January 2000.
[32] Shell FRED 5.1: Fire, Release, Explosion and Dispersion Hazard Consequence Modelling Package, Shell Global Solutions, 2008.