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COMMENTARY:

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Corrosion aspects of non-conventional gases in the natural gas pipeline Network

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Executive Summary

Non-conventional gases produced from biological or other non-geological sources may present new corrosion issues for the UK gas industry. The gases may contain a wider range of contaminants than conventional gases. The main contaminant which would affect the corrosion risk is oxygen (O_2).

Experience in high pressure upstream and transmission operations has shown that the presence of oxygen can lead to localised corrosion or increased corrosion rates in the presence of carbon dioxide (CO_2) or hydrogen sulphide (H_2S) and liquid water. However, most of the experience has been with occasional O_2 contamination due to faulty seals or inert gas systems and the O_2 levels are relatively low compared to biogas. Thus additional studies are needed to quantify or assess the corrosion risk due to the presence of O_2 at percent levels.

This report details a theoretical corrosion risk assessment with calculation of indicative corrosion rates intended to estimate the corrosion risk to steel pipe in distribution networks.

This report covers the following areas

- Collation of data on composition for a range of non-conventional source (NCS) gas compositions.
- Review of studies on the effect of O_2 on oxide films and corrosion products.
- Indicative corrosion rate calculations showing the effect of O_2 percent levels.
- Indicative corrosion rate calculations showing the effect of O_2 partial pressures on various system pressures.
- Identification of failure modes due to usage of biogas in distribution pipeline network.
- Data analysis of historical failures of UK pipeline distribution network.
- Overall corrosion risk assessment.

The collation of compositional data showed that there are significant differences between NCS gas from different sources. Landfill gas contains high concentration of H_2S. Biogas from waste water, farms and energy crops contain high concentration of CO_2 and O_2

Review of studies on the effect of O_2 on oxide films and corrosion products clearly show that O_2 changes the surface corrosion products and O_2 destabilises the protective films.

Results from corrosion rate calculations for the three worst possible conditions at maximum temperatures, using the oil field corrosion model has shown that increase in O_2 percent levels has no effect on low pressure distribution system (75mbar). Corrosion rates increase with increase in O_2 % levels for medium and intermediate distribution systems.

Increase in partial pressures of O_2 increases the corrosion rates for all types of distribution systems.

Historical failure analysis of UK distribution pipeline network show that corrosion and fracture are two principal causes associated with the most of iron and steel pipes in distribution network.

No credible damage failure modes were identified in iron and steel pipes due to the injection of NCS gas in the UK distribution network; this is attributed to the relatively low concentrations of many of the compounds present in NCS gas and is dependent on the presence of water.

Risk assessment results show that, overall risk is low to the integrity of iron and steel pipeline distribution system due to the injection of NCS gas.

Conclusions

1. The overall internal corrosion risk associated with the iron and steel pipe due to the injection of biogas is low. No credible damage mechanism was identified that can cause threat to the integrity of the steel pipes used in the distribution network system.

2. The probability of failure due to the internal corrosion of the iron and steel pipes used in the distribution system is low; this is attributed to the relatively low concentrations of many compounds present in both NCS gas and current natural gas.

3. The effect of increasing oxygen concentration is strongly related to the system pressure. It has little effect on corrosion rates for low pressure (75mbar) distribution systems, whereas in medium and intermediate distribution pressure systems it causes corrosion rates to increase. This is since the increase in corrosion rates is driven by the oxygen partial pressure rather than the oxygen concentration. However, since the higher pressure systems are dehydrated then corrosion will be prevented by the absence of liquid water. Water ingress into medium and high pressure gas systems from adjacent water infrastructure is also extremely unlikely as the majority of water systems operate at pressures below that of the gas systems.

4. The overall risk is estimated to be low regardless of the pipe location. This is since the volume of gas released from a corrosion hole in a low pressure system will be insufficient to result in an incident. The consequence of failure will thus, be a public report of gas and a call out to investigate.

5. The injection of treated and purified biogas into the gas distribution network does not seem to present any additional risk to customers-provided that biogas originated from the four sources such as:
   - Biogas from the anaerobic digestion of sewage sludge, farm waste, energy crops, food waste and bio methane after clean-up
   - Landfill gas – raw and processed
   - Coal mine, coal bed and shale gas – raw and processed
   - Synthetic natural gas (SNG) from the gasification of biogas, biomass or coal

Contents

1 Introduction

Non-conventional gases produced from biological or other non-geological sources may present new corrosion issues for the UK gas industry. With regard to the gas from non-conventional sources (NCS), the network entry and gas safety management regulations (GS(M)R) requirements must be met before the gas can be accepted into the network to safeguard the gas users on the network. The gases from NCS may contain a wider range of contaminants than conventional gases. The main contaminant which would affect the corrosion risk is O_2.

Experience in high pressure upstream and transmission operations has shown that the presence of oxygen can lead to localised corrosion or increased corrosion rates in the presence of CO_2 or H_2S and liquid water. However, most of the experience has been with occasional oxygen contamination due to faulty seals or inert gas systems and the oxygen levels are relatively low compared to biogas. The introduction of NCS gas into the gas distribution network has the potential of introducing a higher concentration of oxygen into the network than 0.2 mol%, the GS(M)R limit. Although this is only likely to occur in upset conditions, it is prudent to examine the impact of O_2 on iron and steel pipes in distribution network. For these reasons additional studies were conducted to quantify or assess the corrosion risk due to the presence of O_2 at percent levels.

1.1 Scope of work

The main aims of the report were:

- To conduct a corrosion risk assessment (CRA) by identifying the modes of corrosion that could occur in a particular system exposed to higher O_2 levels, estimating the probability that they will occur and evaluating the consequences of failure.

- The most probable internal corrosion mechanisms for steel pipe exposed to biogas were identified by considering the stable corrosion products in the presence and absence of O_2.

- Once the most probable corrosion modes were identified then the qualitative probability that they will occur in steel pipes was estimated. The estimate was based upon the likelihood that liquid water could be present.

- Some indicative corrosion rates were then calculated using a combination of standard oilfield corrosion models and atmospheric corrosion models to allow the rates of internal and external corrosion to be compared. The current models are not optimised for high O_2 environments but may indicate the relative scale of rates to be expected.

- The outcome of this study was intended to be the identification of the most probable corrosion modes for biogas, an estimate of the probability of internal corrosion and comparison of the internal and external corrosion risk in steel pipe.

1.2 Definition of key terminology

Hazard is that which has the potential to cause harm or damage, loss, injury or death or environmental degradation.

Failure is the termination of the ability to perform a required function. In the case of corrosion of plant equipment this means failure to contain the relevant fluid (e.g. natural gas etc.).

Risk (criticality) is the combination of the probability of an event and its undesirable consequence. We may be prepared to accept high consequences if the probability of them happening is very low and conversely high probabilities if the consequence is low.

A **consequence** is the outcome from an event, i.e. a particular set of circumstances – in this case loss of containment. This may be measured in various terms, such as of numbers, injury or deaths, environmental impact, financial cost, etc.

Risk analysis is the systematic use of information to identify sources and to estimate the risk. Risk analysis provides a basis for risk evaluation, risk mitigation and risk acceptance. Information can include historical data, theoretical analysis, informed opinions and concerns of stakeholders.

Failure mode is the manner and mechanism of failure. Examples of corrosion failure modes are CO_2 corrosion, H_2S corrosion, Pitting corrosion, Weld corrosion, etc.

Probability is the extent to which an event is likely to occur within the time frame under consideration.

2 Gas Compositions

This section discusses the current GS(M)R specification and compares against the gas composition from non-conventional gas (NCS) sources such as biogas.

2.1 Current Natural Gas composition

Gas transported within the NTS should necessarily comply with GS(M)R [1] which places limits on the concentration of H2S, total sulphur, hydrogen (H2), CO2, and O2 in the gas as well as the dewpoint, wobbe number etc. The contents and characteristics of the natural gas should comply GS(M)R specified under dry normal conditions as specified in Table 1 below,

Table 1 Schedule 3 GS (M) R requirements of dry Natural Gas

Content or Characteristic	Range or Limit
Hydrogen Sulphide	Less than or equal to 5 mg/m³
Total Sulphur	Less than or equal to 50 mg/m³
Hydrogen	Less than or equal to 0.1% molar
Oxygen	Less than or equal to 0.2 % molar
Impurities	Shall not contain solid or liquid material which may interfere with the integrity of operation of pipes or any gas appliance (within the meaning of regulation 2(1) of the 1994 Regulations) which a customer might reasonably be expected to operate;
Hydrocarbon dew point and Water dew point	Shall be at such levels that they do not interfere with the integrity or operation of pipes or any gas appliance (within the meaning of regulation 2(1) of the

	1994 Regulations) which a customer might reasonably be expected to operate;
Wobbe Number (WN)	Shall be between 47.20 to 51.41 MJ/m³
Incomplete combustion Factor (ICF)	Not more than 0.48
Soot Index (SI)	Not more than 0.60

Table 2 The molar composition of UK gas in 2011[2]

	Mean	Maximum
N_2	1.641155	7.510461
CO_2	1.051426	3.117438
Methane	89.7776	98.93579
Ethane	6.026635	10.19198
Propane	1.085926	3.706513
i-butane	0.13439	0.589111
n-butane	0.178981	0.973511
Neo -pentane	0.00126	0.057932
I -pentane	0.035684	0.157832
n- pentane	0.030481	0.133221
Hexane + higher	0.036459	0.137813

The mean and maximum values of the molar composition of the constituents in the UK natural gas in 2011 are given in Table 2. In addition to these components there will be some sulphur-containing compounds - H_2S up to a max of 5mg/m3 and total sulphur of <50mg/m3. Gas may enter distribution pipes from local gas producers as well as from the National Transmission system (NTS). Biologically derived renewable gas, also known as bio-gas is now flowing to consumers [2].

2.2 Gas compositions from Non-conventional sources

The majority of materials degradation risks associated with the introduction of NCS gases into the metal pipelines of the gas distribution network are dependent on the presence of water. It is thus crucial to maintain sufficient dehydration of NCS gases before adding to the natural gas network.

Four classes of raw and processed (cleaned-up) non-conventionally sourced gas were selected for inclusion in this report:

- Biogas from the anaerobic digestion of sewage sludge, farm waste, energy crops, food waste and bio methane after clean-up
- Landfill gas – raw and processed
- Coal mine, coal bed and shale gas – raw and processed
- SNG from the gasification of biogas, biomass or coal

The contents and characteristics of the bio gas that might be used in future gas supply are given in Appendix A-1 [3].

The difference in the current gas entry specification to the future possible gas sources (processed) with respect to CO_2, H_2S, and O_2 levels is summarised in Table 3.

The following conclusions can be drawn:

- The processed biogas can contain 12.5 times greater concentration of CO_2 compared to natural gas.
- The processed landfill gas can contain up to three times more H_2S
- The processed bio gas can contain nearly 10 times more O_2 compared to that in allowed in natural gas.

Table 3 Summary of concentration ranges of key constituents from various NCS gases

Gas Source	CO_2	H_2S	O_2
Natural gas Specification	Less than 2.0 % molar	Less than 5 mg/m³	Less than 0.2 % molar
Biogas from waste water, farms and energy crops.	0.2 – 25% mol%	0 – 10 mg/m³	0 – 2 mol %
Landfill gas	1 – 4.7 % mol %	0 – 15 mg/m³	0 – 2 mol%
SNG from gasification of biogas, biomass and coal	0.47 – 8.9 mol%	No data	No data
Coal mines, coal bed, and shale gas	No data	No data	No data

2.3 Biogas contaminants

NCS gases from biogas contain numerous gas components that can cause integrity threats, but the principal constituents that will be considered in the study are presented in Figure 1.
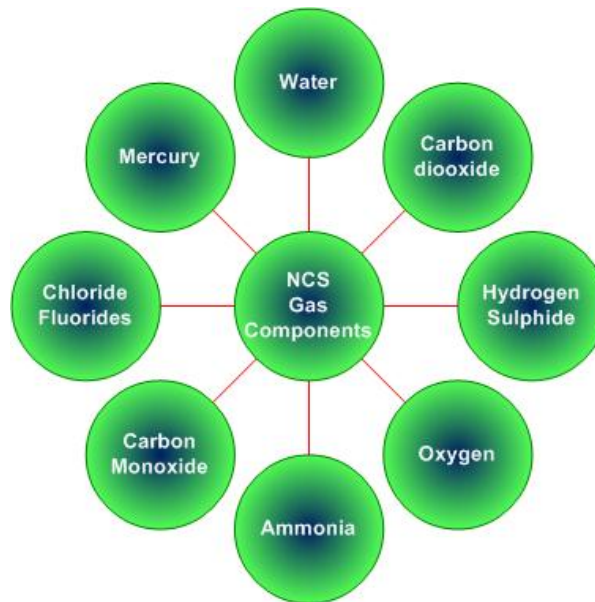
Figure 1 Gas Quality - Non conventional source gas components [3]

Apart from the constituents that are presented above there are other trace elements that exist in the NCS biogas.

3   Oil Field Corrosion Models

Corrosion rates in gas pipelines are calculated using the de Waard & Milliams model, as this is the most commonly used in the oil & gas industry[5]. Many different   models for CO_2 corrosion are used nowadays by engineers in the oil and gas industry. Some are described in the open literature, others are proprietary models. Some of the models are based on mechanistic modelling of the different processes involved in CO_2 corrosion of carbon steel, while other models are mainly based on empirical correlations with laboratory or field data. The models differ considerably in how they predict the effect of protective corrosion films and the effect of oil wetting on CO_2 corrosion, and these two factors account for the most pronounced differences between the various models. Table 4 is a summary of the models that consider protective film effect on corrosion rate.

Table 4 Models considered film effects

Weak film effects considered	Moderate film effects considered	Strong film effects considered
Dewaard & Milliams	Norsok	Tulsa
Cassandra	Corpos	Ohio
Hydrocorr	Lipucor	Predict Model
SweetCor	KSC models	
Electronic corrosion Engineer		

The main inputs for most of the models are

- Partial pressures of CO_2 (pCO_2)
- Temperature
- pH
- Total Pressure

- Glycol Concentration
- Water type
- Liquid velocity
- Water cut

None of the above mentioned models incorporate the O_2 effects in order to predict the corrosion rates.

3.1   Scale formation

The most common type of scale encountered in CO_2 corrosion is iron carbonate ($FeCO_3$). When iron carbonate precipitates at the steel surface it can slow down the corrosion process by

- Presenting a diffusion barrier for the species involved in the corrosion process
- Covering (inhibiting) a portion of the steel surface.

Iron carbonate scale growth and its protectiveness depend primarily (not exclusively) on the precipitation rate. Out of many factors that affect the formation of iron carbonate scales, the most important one is water chemistry. At room temperature the process of precipitation is very slow and unprotective scales are usually obtained, even at very high super saturations. Conversely, at high temperatures >60^0C precipitation proceeds rapidly and dense and very protective scales can be formed even at low super saturation.

Sour corrosion is a series of corrosion mechanisms that are defined by the formation of a type of iron sulphide. Three types of iron sulphide are commonly found in oilfield corrosion; pyrite, pyrrhotite and mackinawite as shown in Figure 2. Pyrite, an ordered solid solution of iron sulphide and elemental sulphur, is found only when elemental sulphur is present. Pyrrhotite is a non-stoichiometric form of iron sulphide that forms in most sour environments. Mackinawite is a form of iron sulphide that forms when H_2S activity is low.
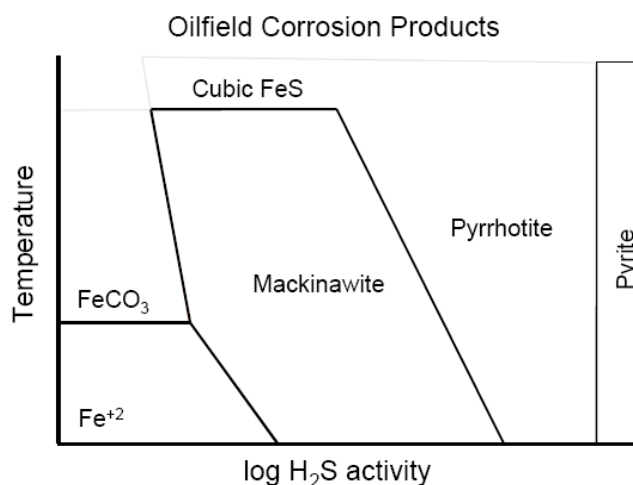

Figure 2 Sulphide corrosion product relationships

Iron sulphide occurs as one amorphous form and up to eight crystalline forms (mackinawite, pyrrhotite, pyrite, marcasite [FeS2], troilite [FeS], greigite, smythite, and cubic FeS). Mackinawite is an iron excess form that forms when FeS is below its saturation concentration in the liquid. Its chemical formula is Fe1+xS, the corresponding iron deficient pyrrhotite is Fe1-xS. Thus mackinawite would be expected to form in low H2S environments while pyrrhotite would be expected in high H2S environments.

3.2   Effect of Oxygen

The introduction of NCS gas into the gas distribution network has the potential of introducing a higher concentration of oxygen into the network than 0.2 mol%, the current GS (M) R limit. Very few studies were conducted to study the effect of O_2 on CO_2 corrosion.

As O_2 is a strong oxidizer when present in a CO_2 system, the following reactions happen

$$O_2 + 2H_2O\,(l) + 4\,e^- \rightarrow 4OH^-$$
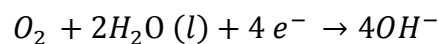
The electrons needed for the above reaction are provided by the oxidation of iron

$$Fe\,(s) \rightarrow Fe^{2+}(aq) + 2e^-$$
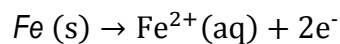
The following reactions also occur in the presence of oxygen and are crucial to the formation of rust:

$$4Fe^{2+} + 4H^+ + O_2 \rightarrow 4Fe^{3+} + 2H_2O$$
$$Fe^{2+} + 2H_2O \rightarrow Fe\,(OH)_2 + 2H^+$$
$$Fe^{3+} + 3H_2O \rightarrow Fe\,(OH)_3 + 3H^+$$
$$2Fe(OH)_2 \leftrightarrow 2FeO + 2H_2O$$
$$Fe(OH)_3 \leftrightarrow FeO(OH) + H_2O$$
$$2FeO(OH) \leftrightarrow Fe_2O_3 + H_2O$$
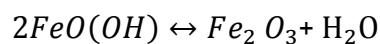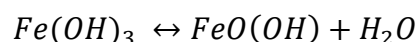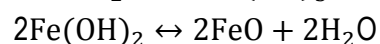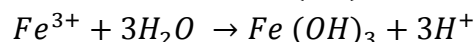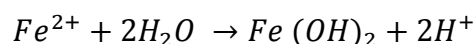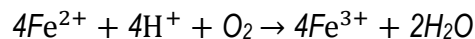
The presence of natural gas and CO_2 was combined with O_2 in a corrosion study by Durr and Beavers [6]. It was found that with the presence of O_2 in natural gas, the highest corrosion rates were noticed at the vapour/liquid interface, followed by liquid and then the gas phase. O_2 is the most corrosive of the gases. Generally the presence of O_2 results in an increase in corrosion potential, which is attributable to the additional cathodic reactions of O_2. The higher corrosion associated with partially immersed components is due to the greater availability of O_2 in the vapour/liquid interface.

Tjepkema et al [6] found that pipelines could survive at least 50 years in the presence of up to 10% CO_2 and moisture if O_2 is excluded, however the corrosion was severe when 5000 ppm O_2 was added. Both laboratory and field studies agreed that inhibition of corrosion becomes more difficult when even small amounts of O_2 enter a sweet brine [7].

A research programme that includes long term laboratory testing conducted to investigate the effects of oxygen under wet gas pipelines conditions has produced a CO_2 corrosion rate prediction model which includes oxygen levels [8]. The model shows 100ppmv of oxygen is enough to cause significant damage to the pipeline integrity of the wet gas pipeline. Increasing oxygen content from 0.2 to 1% doubles the carbonic

acid corrosion rate due to destabilisation of protective films. Increasing the oxygen levels from 0.2 to 3% increases the corrosion rate by a factor of four to five.

The effect of percentage O_2 levels on O_2 partial pressures and corrosion rates were calculated and discussed in detail in later sections.

In order to calculate the indicative corrosion rates for the worst case scenarios experienced by the distribution pipeline network the corrosion model proposed by [8] is used in the current study.

$$CR = 8.7 + 9.86 \times 10^{-3} (O_2) - 1.48 \times 10^{-7} (O_2)^2 - 1.31 (pH) + 4.93 \times 10^{-2} (CO_2) (H_2S) - 4.82 \times 10^{-5} (CO_2) (O_2) - 2.37 \times 10^{-3} (H_2S) (O_2) - 1.1 \times 10^{-3} (O_2) (pH)$$

CR = general corrosion rate, in mpy (mils per year, 1 mil is 0.001 inches)

O_2 is the oxygen concentration of the gas, in ppmv

CO_2 is the carbon dioxide partial pressure in the gas in psi

H_2S is the hydrogen sulphide partial pressure in the gas, in psi and

pH is the initial pH

The model is applicable to all iron based alloys including cast and ductile iron and conventional pipeline steels. Since O_2 is one of the bio gas constituents that is largely different from the natural gas, it is important to study the effect of O_2 on corrosion rates for distribution pipeline network system.

3.2.1 Effect of increased oxygen levels on Oxide films

Studies were undertaken by Martin [7] covering both field and laboratory tests where the corrosion system was carbon steel exposed to oil field brines containing dissolved CO_2, dissolved H_2S and contaminated with O_2. The results showed that intrusion of O_2 into the oil field brines changes the surface iron carbonate films to make the reduction of H_2CO_3 more efficient in sweet systems. The same study also showed that O_2 changes the surface corrosion product, which influences interaction with inhibitor molecules, making corrosion inhibition more difficult in O_2 contaminated systems than in pure CO_2/H_2S environments. However distribution systems are uninhibited and thus the effect of O_2 on inhibition is irrelevant to the current study, nevertheless it is important to understand the effect of O_2 on CO_2/H_2S environments from a practical perspective.

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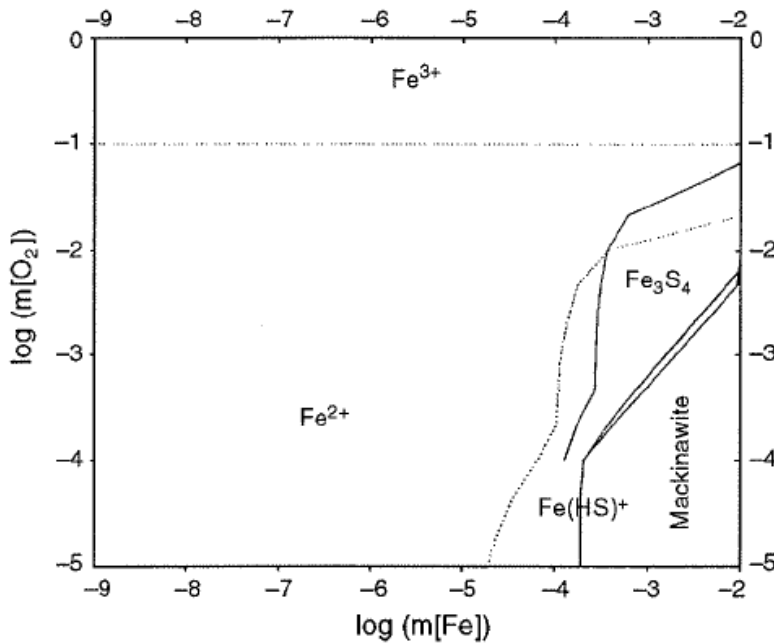
Figure 3 Stability diagram for a system containing 0.5 psi H_2S as a function of iron and O_2 concentrations
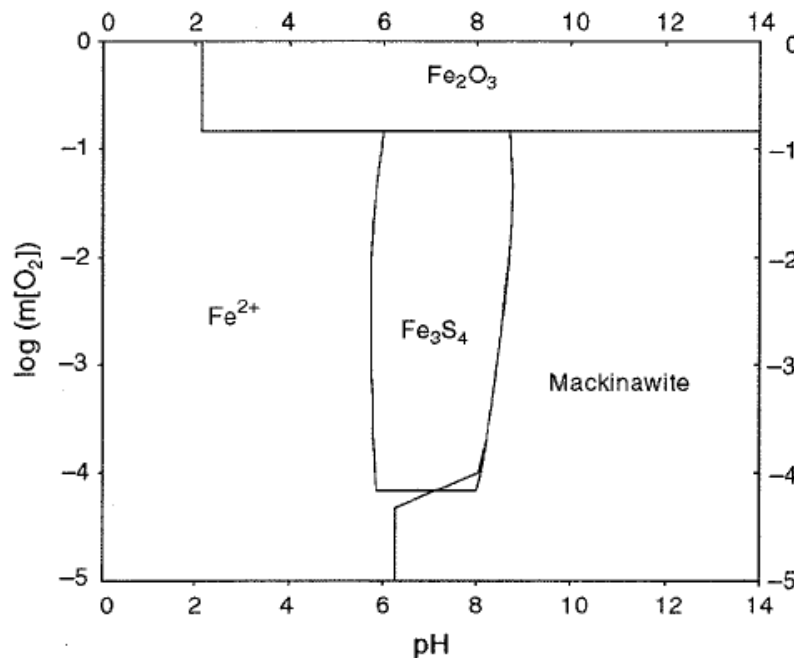
Figure 4 Stability diagram for a system containing 10^{-4} moles/kg dissolved iron and 10 psi CO_2 as a function of pH and H_2S concentration.

Sridhar et al [9] constructed the stability diagram as shown in Figure 3, for a system containing 0.5psia H_2S as a function of the amount of dissolved iron and O_2 added to the vapour phase. For gas Phase containing 100 moles of neutral gas, 10^{-1} moles/Kg O_2 on the vertical axis corresponds to 1000ppmv O_2, 10^{-2} moles/kg corresponds to 100 ppmv. As shown in Figure 4, the increase in the amount of oxygen results first in the conversion of mackinawite into Fe_3S_4 at 1ppmv O_2 (10^{-4} moles/kg on the vertical scale). However these oxygen levels are very high compared to the distribution pipeline system where the H_2S levels are around 0.000145 psi in low pressure system.

The boundary between mackinawite and Fe_3S_4 depends on the amount of dissolved iron, further increases in the amount of O_2 results in the dissolution of Fe_3S_4 and shift of the state of the system to the active dissolution range.

Lyle and Shutt [8] reported the effect of slowly flowing solution on the corrosion rate in O_2 containing systems. Under slow flowing conditions, build-up of corrosion products is minimised in the vessels. Based on these results Sridhar et al constructed the stability diagram assuming the pH and O_2 as independent variables and the amount of dissolved iron as a parameter as shown in Figure . The Fe_3S_4 and mackinawite precipitation lines are observed at a pH slightly greater than 6. Change in crystal structure from mackinawite to Fe_3S_4 promotes disruption of the protective sulphide and increased localized corrosion.

4 Pipelines Considered

The pipelines considered for this study are mainly distribution pipelines. The low-pressure distribution pipeline network takes gas from the national transmission systems (NTS) and delivers it to homes and businesses.

The materials used in the construction of the distribution pipeline are both metallic (steel, cast iron) and non-metallic materials (polyethylene). The pressure experienced by the distribution pipelines are in the range of 0.3 to 250 psi, however they mainly operate at lower pressures than the transmission pipelines. The three classes of distribution pipelines can be defined as low pressure (LP) less than 75 mbar, medium pressure (MP) 75 mbar to 2 bar, Intermediate pressure (IP) 2 bar to 7 bar.

Distribution pipelines can measure as large as 24 inches in diameter, however, most are much smaller, ranging in size from 24 inches to 2 inches. The current study is focussed on assessing the impacts of failure modes due to bio gas contaminants on steel materials.

The effect of increased O_2 levels on the copper pipework used in domestic premises has not been considered as part of this study.

4.1 Corrosion of Distribution Pipelines

This section briefly describe the two main types of corrosion that can occur in distribution pipelines during their service life, they are

1. Internal corrosion
2. External corrosion

4.1.1 Internal Corrosion of Pipelines

The most common forms of internal corrosion due to acid gas contamination in hydrocarbon production systems are CO_2 corrosion (sweet corrosion), and H_2S corrosion (sour corrosion).

Internal corrosion is not uniformly distributed along a pipeline as it depends on several factors and it is the result of:

- Water slippage in gas lines
- Changes in pH, Temperature
- Topography
- Deposits, bacterial build up, microbiological activity
- Erosion corrosion at elbows bends and protective films are particularly susceptible to localised erosion corrosion under highly turbulent conditions.
- Through wall cracks due to sulphide stress corrosion cracking
- Pipe wall delamination due to hydrogen damage, hydrogen induced cracking.

Often corrosion is more severe in low spots where water is collected. Internal corrosion direct assessment (ICDA) can be used for determining integrity for the internal corrosion threat on pipeline segments that normally carry dry gas but may suffer from short-term upsets of wet gas or free water (or other electrolytes).

4.1.2   External Corrosion of Pipelines

External corrosion of pipelines typically occurs where coating defects allow contact of the steel with the wet soil. The common features associated are:

- Soil aggressivity (parameters like pH, sulphate content, and chemical contamination) can lead to general corrosion and pitting/leakage.
- Bacterial activity (sulphate reducing bacteria can lead to rapid localised pitting/leakage)
- Environmental cracking (slow change in local pH next to metal in presence of O_2 causes carbonate/bi-carbonate cracking/pipe rupture).
- Coating disbondment (contact with corrosive species and no cathodic protection can cause localised pitting and cracking with leakage/rupture). Also cathodic disbondment is caused by cathodic protection, when you have overprotection.
- Poor cathodic protection management (inadequate or no protection in local areas can cause localised corrosion and pitting with leakage). But cathodic protection is not very common on distribution systems.

4.2   Likely failure modes from Bio Gas constituents

Failure mode – anticipated operational conditions used to identify most probable failure modes, the damage mechanism and likely locations. Table 5 details the failure modes associated with biogas contaminants.

Table 5 Summary of possible failure modes and description of failure modes

Biogas Contaminant	Failure Mode
Hydrogen sulphide (H_2S)	Hydrogen sulphide corrosion occurs If there is H_2S slippage and water is present. Pitting can occur typically at 6 o' clock position. The degradation morphology can include sulphide stress cracking (SSC) and hydrogen induced crack (HIC), which occurs especially at higher applied or residual stress locations. (e.g welds, bends, welded on turn-ons. The stresses experienced by the low pressure distribution systems are significantly low to

	cause SSC. Transmission systems can have up to 85% SMYS, so SSC is credible but it is unlikely in distribution. HIC comprises cracks and blisters generally associated with non-metallic inclusions particularly elongated manganese sulphide, HIC is not related to stress The materials are susceptible if not meeting ISO 15156 criteria.
Carbon Dioxide (CO_2)	In the presence of water, CO_2 dissolves to form carbonic acid which then corrodes iron based alloys. CO_2 corrosion can occur in pipework straights (6 o'clock)/bends/tees/reducers. Welds, heat affected zone (HAZ) and downstream of welds are susceptible to CO_2 corrosion.
Oxygen (O_2)	O_2 Corrosion mainly occurs for a limited period during conditions when water may enter the pipes from external sources or from leaking joints in low pressure mains. The main causes O_2 corrosion can occur in all aerated water wetted locations, pipework with straight lengths, bends, and welds.
Ammonia	NCS gasses from biogas or landfill gas can contain ammonia. Anhydrous ammonia can cause stress corrosion cracking in carbon steel. Stress corrosion cracking is accelerated by cold work, welding applied stress and by use of high strength steels. The concentration found in the NCS gas is insignificant to cause stress corrosion cracking due to ammonia in distribution pipeline network
Carbon Monoxide	NCS gases, especially from SNG, may contain carbon monoxide and there is potential for stress corrosion cracking, but only if water is present. SCC can occur in gas pipelines when the internal surface of the pipe wall is exposed to an environment of water, carbon monoxide and carbon dioxide. Accumulation of condensate and CO levels above 10% appears to have been contributing factors with SCC occurring at the girth welds.
Chlorides/ Fluorides	Chloride, fluorides can cause the SCC of stainless steels. The minimum temperature required to cause SCC for austenitic stainless steels is 60^0C. If oxygen is not present cracking of austenitic stainless steels can occur if chloride levels are greater than 200ppm. In the presence of oxygen cracking can occur at 4ppm chloride levels. Since distribution pipelines operate below 60^0C, the risk of SCC in distribution pipelines is low. However in the presence of small concentrations of chlorides corrosion rates slightly increases due to the breakdown of the corrosion product/passive film formed on distribution pipelines and promote localised pitting.
Mercury	Mercury can present a severe integrity threat to aluminium alloys as it can form an amalgam and consequent corrosion (amalgam corrosion) and can also lead to liquid metal cracking or liquid metal embrittlement (LME) which is a form of EAC. But distribution systems are not made of aluminium. Mercury in NCS gas could cause problems when the gas is burnt. At high temperatures amalgams can be formed. Stainless steels have been found to be susceptible to amalgam corrosion under the conditions of the presence of water and a break in the protective oxide film. Stainless steels have been found to not be susceptible to LME from mercury exposure. Carbon steels have been found to be non-susceptible to LME from mercury exposure.

5   Indicative Corrosion Rate Calculations

Corrosion rate calculations were performed using CORRMOD excel file based on the model generated by Lyle and Schutt [8]. One thousand iterations were run on the excel sheet for each case and the corrosion rate is recorded. The pH values are calculated using the CORPHU pH software for each case. Screen shots of the models used are given in the Appendix, see Figure 18 and Table A 7.

For the purpose of this study the corrosion calculations will be simplified to consider the following cases. Three main cases were considered that relate to the extreme conditions that a distribution pipeline might experience in its service life due to the injection of processed biogas into the distribution pipeline.

The cases considered for corrosion calculations were presented in Table 6, in all the cases the maximum temperature of 38^0C was considered in calculations, as this is the current GS(M)R maximum limit for distribution pipeline network.

The parameters considered in the corrosion rate calculations are summarised below:

- Four different total line pressures (0.075, 2, 7 &14bar) representing the range found in distribution pipeline networks were considered for each case to calculate the corrosion rates.

- The maximum H_2S level considered to be 15 mg/m^3, as processed landfill gas can contain this level of H_2S.

- The maximum CO_2 level considered to be 25 mol%, as processed biogas from waste water, farms and energy crops might contain this level of CO_2.

- The effect of O_2 on all the cases presented was studied in detail for four types of total line pressures, starting from 0.25% with increments of 0.25% to a maximum of 5%.

Table 6 Cases considered for corrosion rate calculations

Case Type	Input Parameters			
	Pipeline Pressure	*Mol % C0$_2$*	*H$_2$S mg/m^3*	*Temperature ^{0} C*
Case 1	75 (mbar)	25	15	38
	2 (bar)	25	15	38
	7 (bar)	25	15	38
	14 (bar)	25	15	38

Case 2	75 (mbar)	2	5	38
	2 (bar)	2	5	38
	7 (bar)	2	5	38
	14 (bar)	2	5	38
Case 3	75 (mbar)	25	5	38
	2 (bar)	25	5	38
	7 (bar)	25	5	38
	14 (bar)	25	5	38

Details of the O_2 levels considered for corrosion rate calculations are presented in the appendix.

5.1 Effect of Oxygen on Corrosion rates

The effect of increased O_2 levels was investigated using the CO_2 model described in the previous section. This section presents results on the effect of percentage O_2 levels for different distribution pressure systems for the three extreme cases presented above.

5.1.1 Effect of percentage O_2 levels

Figure 5, Figure 6, & Figure 7 shows that with an increase in O_2 concentration the corrosion rate increases for the three cases considered. The results clearly demonstrate that

- An increase in the percentage levels of O_2 has minimum effect on corrosion rates for low pressure (75mbar) systems in all the three cases.
- An increase in the percentage levels of O_2 has increased the corrosion rates for the pressure systems above 75mbar.
- For a fixed percentage of O_2 level (3%) the corrosion rates increases by tenfold from low pressure systems (75mbar) to 14 bar pressure system in all the three cases,
- The maximum corrosion rate noticed for 14 bar pressure system is 0.73mm/year at 3.5% O_2 level in case 2.

Above 75mbar system pressure, increases in O_2 levels increase the corrosion rate indicating the total system pressure is important for O_2 levels to have a significant impact on distribution system.
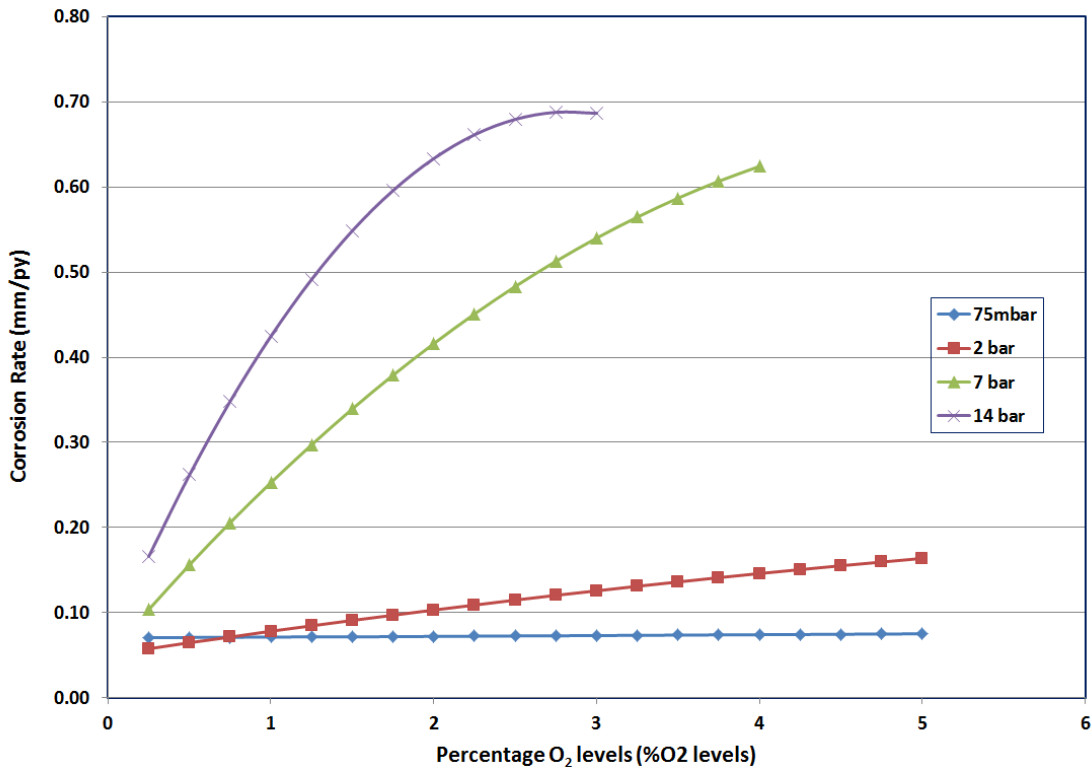
Figure 5 Effect of O_2 concentration on corrosion rates for case 1.
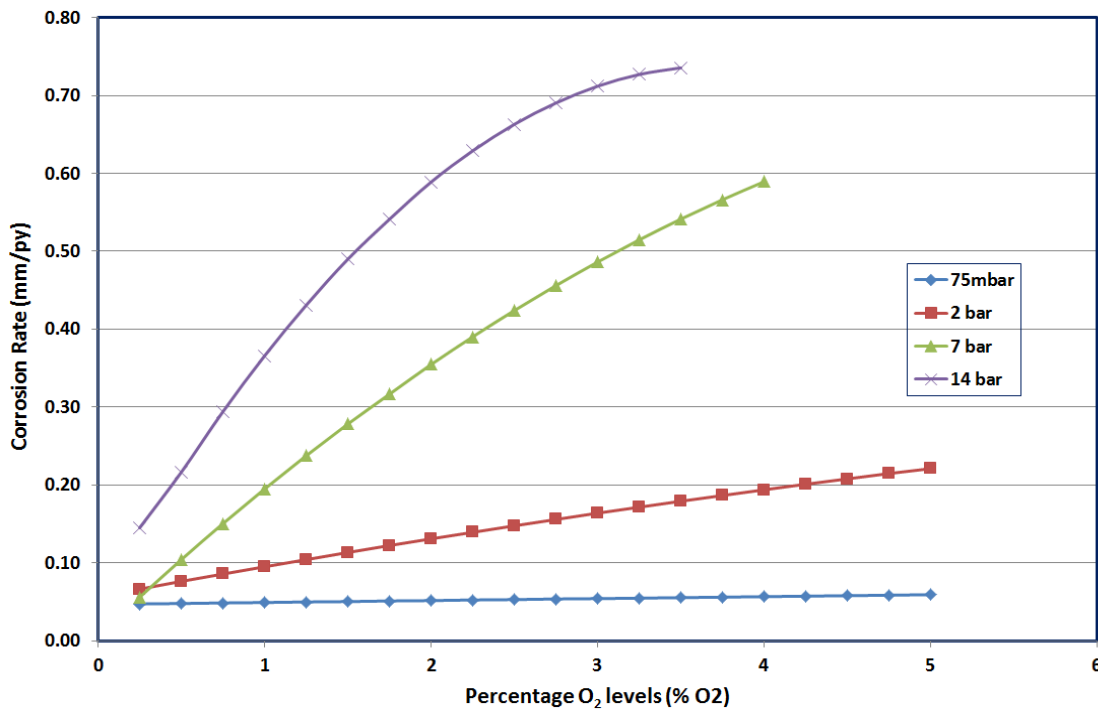
Figure 6 Effect of percentage O$_2$ levels on corrosion rate for case 2
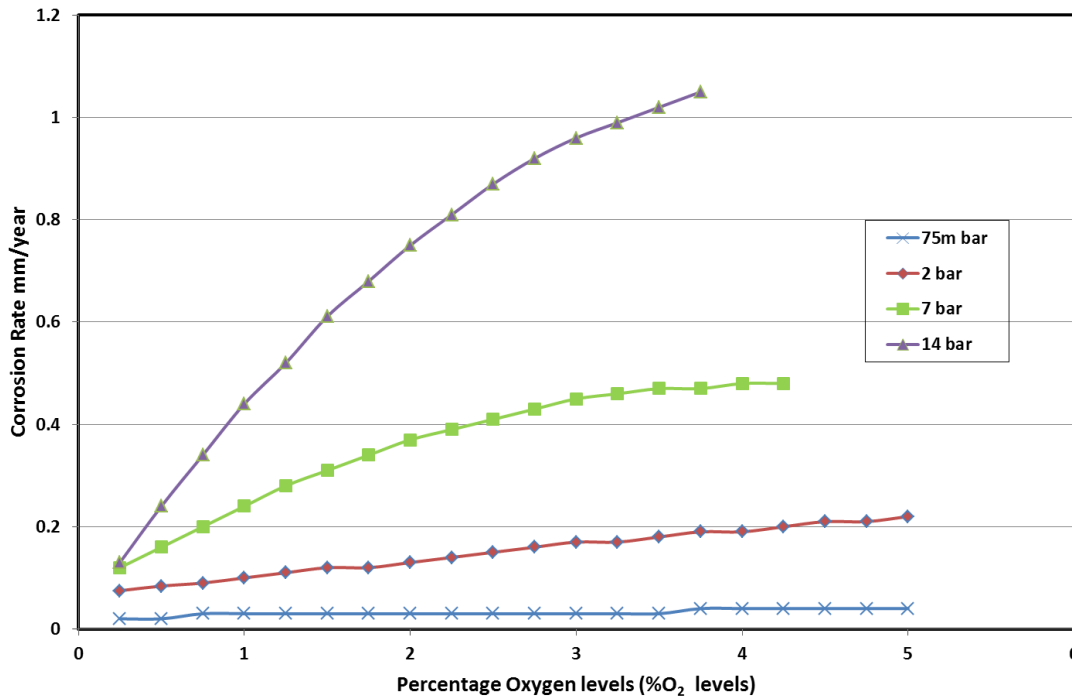
Figure 7 Effect of percentage O$_2$ levels on corrosion rates for case 3

5.1.2   Effect of O$_2$ partial pressures:

The effect of O$_2$ partial pressures for two different cases (case 1 & 2) on corrosion rates is shown in Figure 8 & Figure 9.

Figure 8 Effect of partial pressure of O₂ on corrosion rate for case 1

Figure 9 Effect of partial pressure of O₂ on corrosion rate for case 2

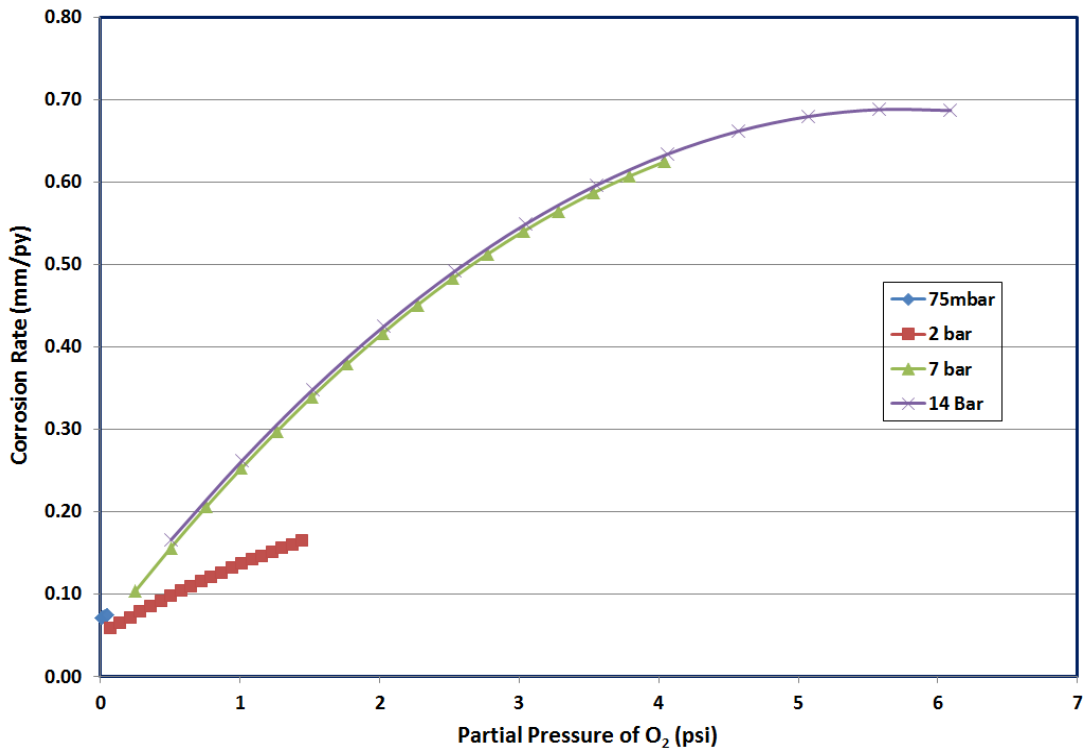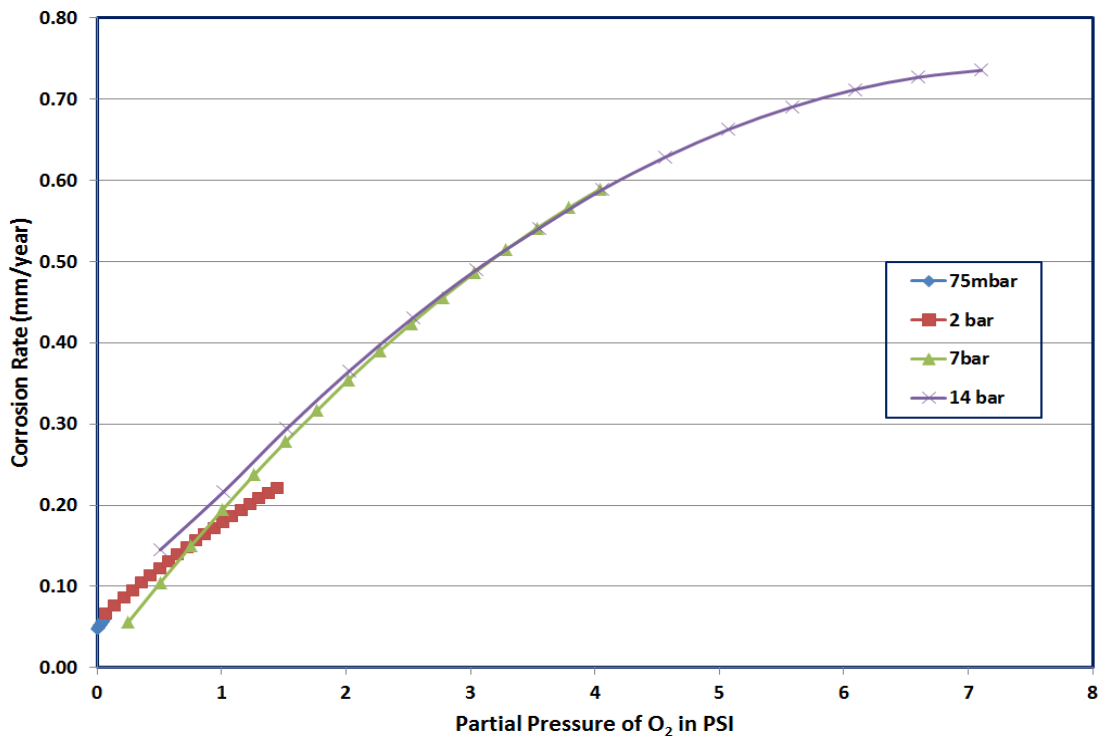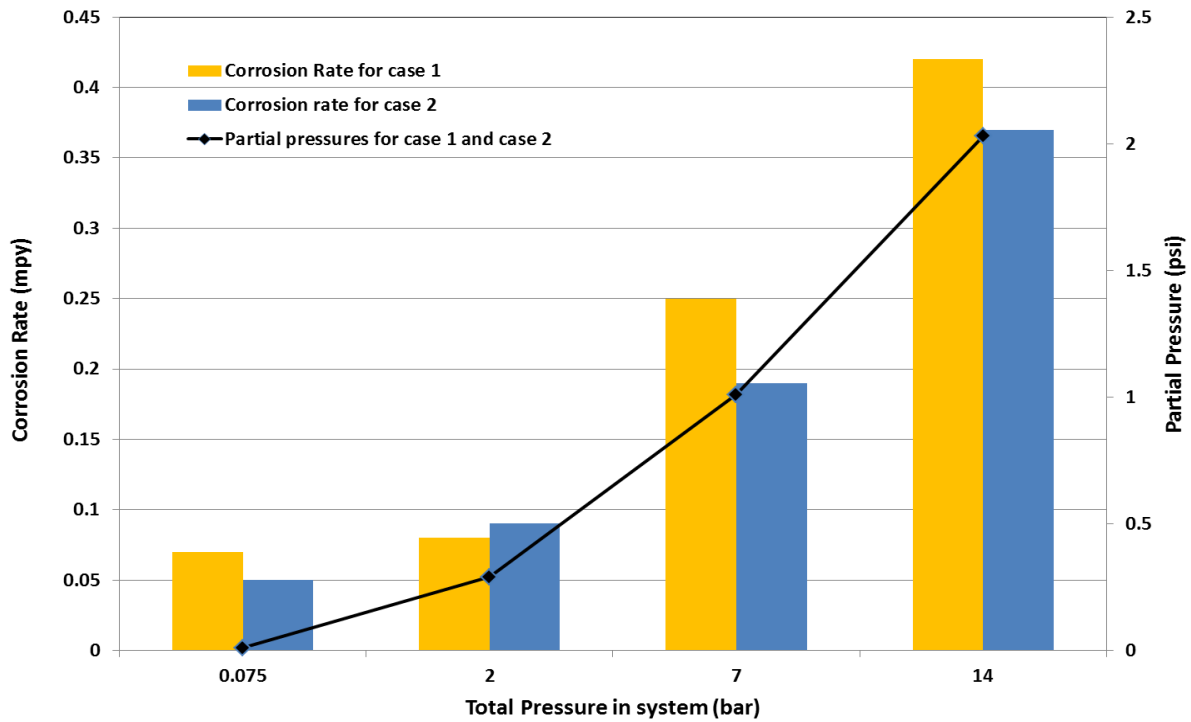Figure 10 Effect of fixed O_2 level (1%) on corrosion rate and partial pressure for cases 1& 2
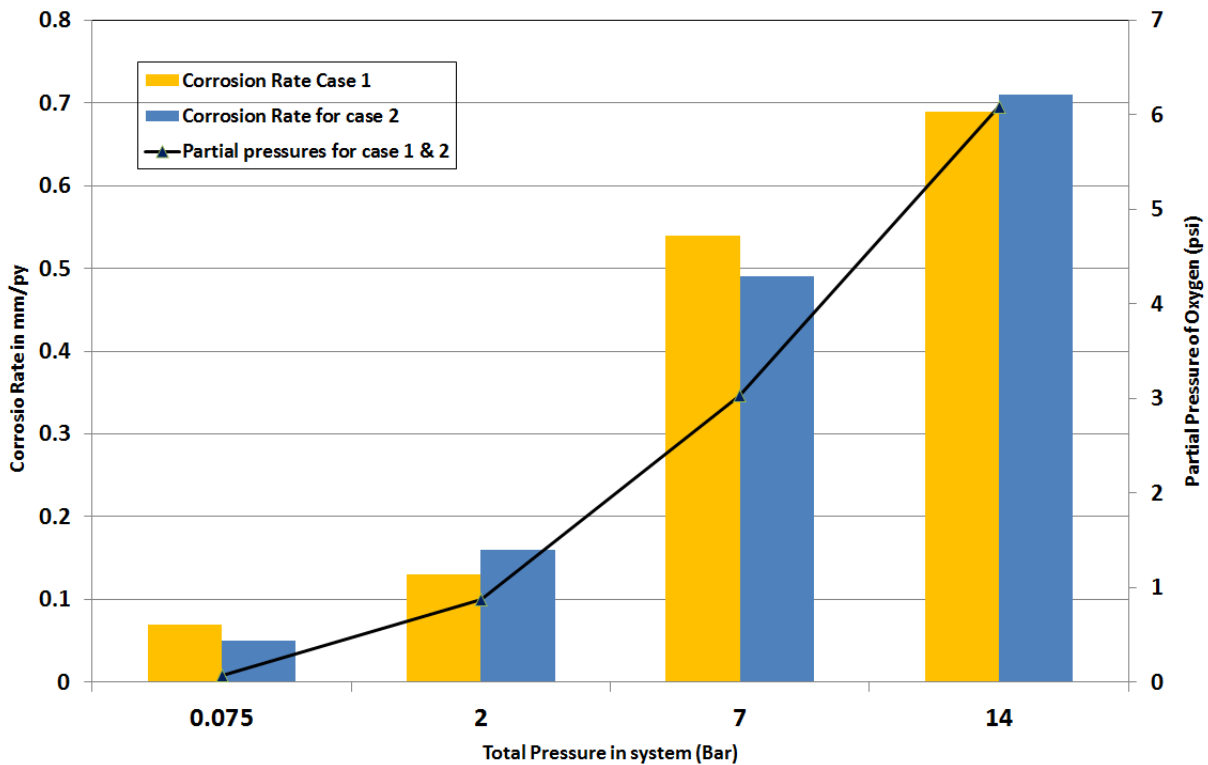
Figure 11 Effect of fixed O_2 level (3%) on corrosion rate and partial pressure for cases 1 & 2

The results from Figure 8, Figure 9, Figure 10 & Figure 11 are summarised below:

- An increase in O_2 partial pressures for different total pressure system has accelerated the corrosion rates in all the cases studied.

- Corrosion rates are similar for 7 and 14 bar systems for different O_2 partial pressures.

- For fixed oxygen percentage levels (3% is considered in this case), the O_2 partial pressure increases the corrosion rates for different system pressures.

- The O_2 partial pressure (activity) drives the corrosion process; a given concentration of O_2 will be more corrosive in a high system pressure than a low system pressure. However, since the higher pressure systems are dehydrated then corrosion will be prevented by the absence of liquid water.

A number of incidents of water ingress into low pressure mains have occurred. Many of these incidents are due to a burst water main causing a flow of high velocity water containing debris which scours through the wall of the iron gas main [15] and water pressure is then sufficient to allow water ingress. This is a much less likely scenario for medium and high pressure gas mains as they are generally constructed of steel which has superior erosion resistance. In the event that the gas mains were perforated water ingress would only occur if the water pressure were higher than the gas pressure. The majority of water infrastructure operates at pressures less than 4 bar and thus would not cause water ingress to medium and high pressure gas mains. The only water infrastructure with high enough pressures to allow ingress into medium and high pressure gas mains would be the large diameter water trunk lines. Thus if a medium or high pressure gas main were in the immediate vicinity of a failed large diameter water trunk main it is theoretically possible that water could enter the gas system. However, no such incident has been recorded in either the gas or water industries and it is regarded as a very low probability event.

An alternative source of water is entry of ground water through a corrosion hole in the gas main. This is only possible for low pressure mains as for a 7 bar medium pressure system a water depth of ~80 m would be required to overcome the gas pressure and allow water entry. It is highly unlikely that this depth of water would ever be encountered in a UK distribution system.

In the low probability scenario where water ingress into a medium or high pressure system occurs the actual wall loss will be dependent upon the time of wetness. Corrosion would only be an issue if the water entry was not detected and thus an extended period of corrosion occurred. As stated above the only scenario for water ingress into a medium or high pressure gas system would be failure of a high pressure water trunk line which is a major incident that would definitely be detected and remedial measures taken to remove water from the gas infrastructure.

The results from this study indicate that internal corrosion is a low probability failure mode for distribution systems. This is since in low pressure systems which can suffer water ingress, the partial pressures of oxygen and other corrosive gases are too low to cause a significant corrosion rate. In higher pressure systems the partial pressures of oxygen and other corrosive gases allow significant corrosion rates; but the combination of dehydrated gas and pressures high enough to prevent water ingress prevent corrosion from starting.

5.2   Comparison with external corrosion rates

Considerable research has been performed to identify the factors which influence the external corrosion rate of buried iron and steel pipes. Commonly used models consider the resistivity, pH, redox potential, sulphide content and moisture level of the soil [12]. The American Water works Association model uses a point scoring system to assess the corrosivity of soils. The points are assigned according to the soil characteristics as shown in Table 7. A score of 10 or more indicates that corrosion protection methods such as coating or cathodic protection are required.

Corrosion rates of bare steel in soil vary widely depending upon the type of soil. Table 8 shows some typical rates quoted in ASME B31.8S [13]. Comparing the external rate from Table 8 to the internal rates from Figure 10 and Figure 11 shows that for pressures up to 2 bar the external rate is more than the internal rate. At pressures ≥7 bar the internal rate exceeds the external rate but since gas at these pressures is dehydrated then the effective corrosion rate is zero (as liquid water is required for corrosion) and again the external rate dominates.

Soil Parameter	Assigned Points
Resistivity (ohm cm)	
<700	10
700 - 1000	8
1000 - 1200	5
1200 - 1500	2
1500 - 2000	1
> 2000	0
pH	
0-2	5
02-Apr	3
4-6.5	0
6.5-7.5	0
7.5-8.5	0
>8.5	3
Redox Potential (mV)	
>100	0
50-100	3.5
0-50	4
<0	5
Sulphides	
Positive	3.5
Trace	2
Negative	0
Moisture	
Poor drainage continuously wet	2
Fair drainage generally moist	1
Good drainage generally dry	0

Table 7. AWWA soil corrosion assessment model

Corrosion Rate (mm/y)	Soil Resistivity (Ohm cm)
0.075	>15,000 and no active corrosion seen
0.15	1000 – 15,000 and/or active corrosion
0.3	<1000 (worse case)

Table 8. Soil corrosion rates (from ref [13])

6 Pipeline Risk Assessment Process

For a formal pipeline risk assessment, as part of an integrity management programme, each pipeline is first divided into individual segments for which different risk considerations apply in terms of threats and hazards, the probability that each hazard may occur and the consequences if it does.

The divisions are chosen to cover the pipelines in segments which are of convenient size, are geographically distinct or have differing risk components. The segments also provide for scoping inspection work in manageable parts. The threats which apply to each section are listed and the associated risks developed. The assessments are firstly made using qualitative methods and judgements of the particular conditions.

Suitable inspection and control measures are then set out for each of the threats anticipated for each segment and the resulting residual risk is estimated qualitatively. The objective is to manage the risks, reducing each to a residual level which is as low as is reasonably practicable. However, in the current study the pipeline is treated as one single unit and is not divided into segments and is qualitatively assessed. This is because this study addresses the risk due to a change in gas composition on an entire system rather than at the individual pipeline level.

The qualitative corrosion risk assessment is a formal review that identifies the probability of a corrosion related failure and its consequences relating to the loss of containment and the consequential hazards should a failure occur. The details of the methodology for the qualitative corrosion risk assessment are described in detail elsewhere [11].

Corrosion risk is normally expressed as follows:

Corrosion Risk = Probability of Corrosion Related Failure x Consequences of Such a Failure

Where:
- Probability of failure is estimated based upon the types of corrosion damage expected to occur on a component, and the deterioration mechanisms, rates and susceptibilities are the primary inputs into the probability of failure evaluation.
- Consequence of failure is measured against the impact of such a failure evaluated against a number of criteria, which as a minimum would include safety, environmental and operational impacts, which would result should a failure occur.

The various consequences of any incident arising from loss of integrity are generally complex and have to be considered individually. It is usually only practicable to divide consequences into 3 broad areas: Safety Environmental and Commercial. Aspects such as the reputation of the operator, for instance, may be considered as part of commercial consequences. In this assessment, only one consequence rating is given to each threat analysed.

Qualitative probability of failure and consequence analysis:

A qualitative method involves identification of the units, systems or equipment, the materials of construction and the corrosive components of the processes. On the basis of knowledge of the operating history, future inspection, and possible materials deterioration, probability of failure can be assessed separately for each unit, system, equipment grouping or individual equipment item. Engineering judgement is the basis for this assessment. A probability of failure category can then be assigned for each unit, system, grouping or equipment. The categories are described with words (such as high, medium, or low).

For a qualitative method, a consequences category (such as "A" to "C", or high, medium, or low) is typically assigned for each unit, system, grouping or equipment item.
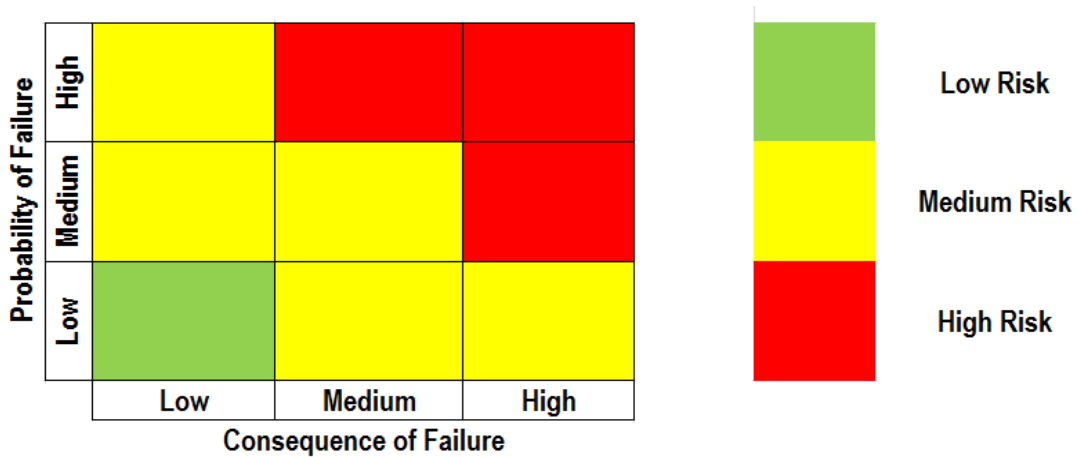
Figure 12 3X3 Risk assessment matrix used in the assessment

Figure 12 shows an example of the 3X3 risk assessment matrix. In each case to determine the probability of failure the pipeline should be assessed on the basis of:

- Internal corrosion threat
- External corrosion threat

In the current study external corrosion is not assessed in detail, historical information collected between 2006 and 2010 for the distribution pipelines will be used to quantify the percentage of external corrosion failures in distribution pipelines. However, the comparison of internal and external corrosion rates in section 5.2 indicates that the probability of a failure due to external corrosion in a low pressure system is equal or

higher to that for internal corrosion. Higher pressure systems are dehydrated and thus the only credible corrosion failure mode is external corrosion.

The indicative internal corrosion rates due to bio gas constituents were calculated using the available oil field corrosion models. The effect of oxygen on internal corrosion rates for different types of distribution pipelines is already presented in the previous sections.

Consequences of failure risks are assessed based on:

- Safety/hazard threat
- Environmental threat
- Operations threat

Figure 13 shows schematically the factors that are considered in main risk prioritisation scheme (MRP) model in order to calculate the corrosion risk of distribution pipelines iron and steel pipes. [3]
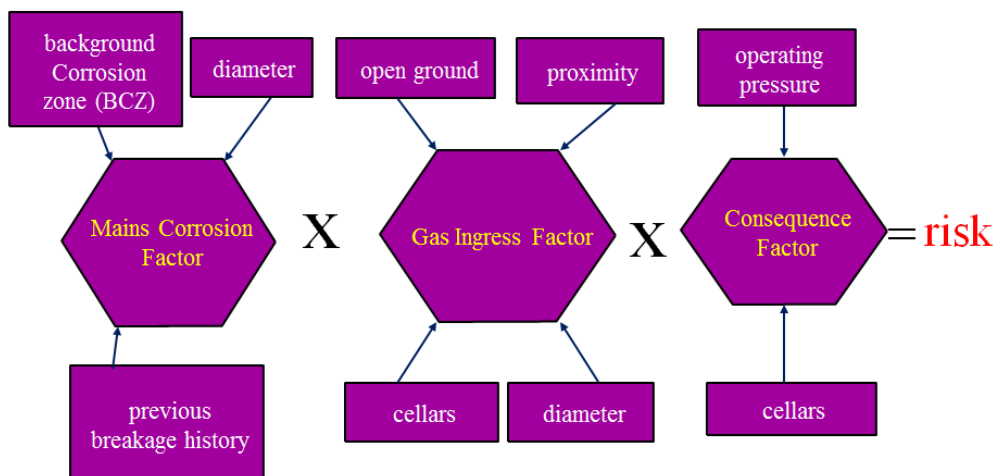
Figure 13 Risk Model for corrosion failures in distribution pipelines [4]

The model presented in Figure 13 is based on three main stages:

- Through wall corrosion (MCF)
- Gas in Building (GIF)
- Consequence of Ignition (CF)

6.1 Probability of Failure analysis

A probability of failure analysis has been undertaken on steel pipe for the constituents of the biogas. Table 9, summarises the overall probability of failure associated with using steel pipe in the gas distribution system.

Table 9 Probability of failure analysis of steel pipe subject to a biogas environment

Material/System	Principal Threat	Failure mode	Overall Probability of Failure
Steel Pipe	Hydrogen sulphide (H_2S)	• Pitting • Stress Cracking — Sulphide stress cracking (SSC) — Hydrogen Induced Cracking (HIC) — Blistering	**Low** If dehydration is effective, also SSC risk is low as stresses in distribution pipeline are not sufficient to cause crack initiation.
Steel Pipe	Carbon dioxide (CO_2)	• General Corrosion (flow induced) • Localised Corrosion (Low flow) • Preferential weld corrosion	**Low** If dehydration is effective.
Steel pipe	Oxygen	• General oxygen corrosion • Oxygen corrosion at welds • Oxygen corrosion at the inlets/leaks	**Low** If dehydration is effective. Also the calculated corrosion rates are quite low for most of the distribution systems for various O_2 percent levels.
Steel pipe	Ammonia	• Stress corrosion cracking	**Low** No water required for carbon steels. Ammonia concentrations are too small to cause SCC.
Steel Pipe	Carbon monoxide	• Stress corrosion cracking	**Low** If dehydration is effective.
Steel Pipe	Chloride/fluorides	• Localised corrosion • Stress corrosion cracking	**Low** As little stainless steel present at the vulnerable temperatures in gas and transportation distribution systems.
Steel Pipe	Mercury	• Liquid metal embrittlement	**Low** Carbon steels found to be non-susceptible to LME.

6.2 Consequence of failure analysis

A qualitative failure analysis method involves identification of the units, systems or equipment's, and the hazards present as a result of operating conditions and process fluids. On the basis of expert knowledge and experience the consequences of failure are estimated. One way to rank the consequences category assigned for each unit, system, grouping or equipment item is typically "high", "medium" and "low". Table 10 summarises the scenarios considered in the qualitative consequences assessment. Each scenario listed in the table consists of many sub-events that account for different failure modes under different operating conditions.

The three main issues related to the distribution pipelines are

- Cast Iron is subject to fracture – can be sudden release of gas into nearby property
- Ductile Iron can corrode through wall
- Steel can corrode through wall

Historical data related to the location of failures, reasons for the failures, and type of distribution pipeline involved in failure are presented in Figure 14, Figure 15, Figure 16, & Figure 17.
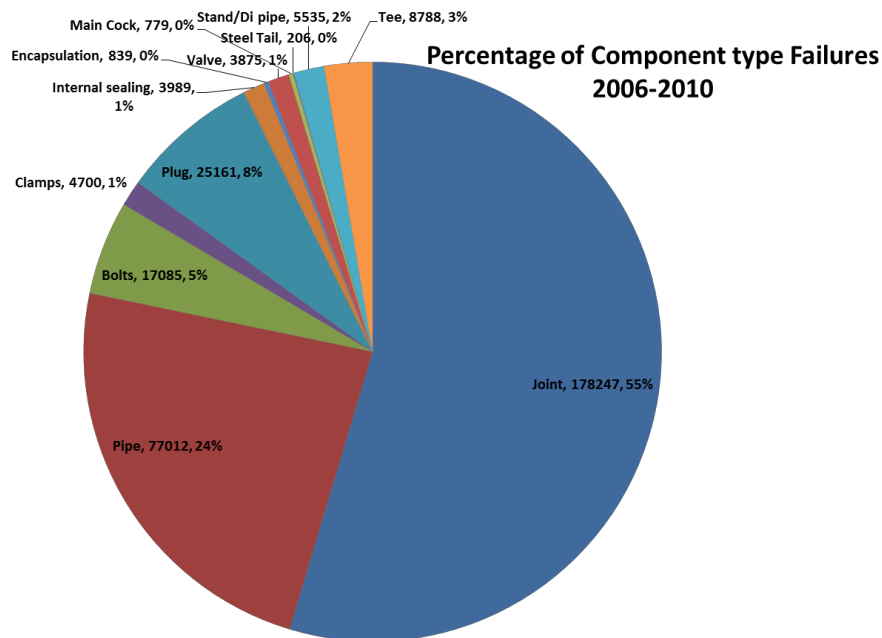
Figure 14 Percentage of component type failures noticed during the period 2006 to 2010

Data in Figure 14 shows that most of the failures are associated with pipe joints and pipes in the distribution mains.
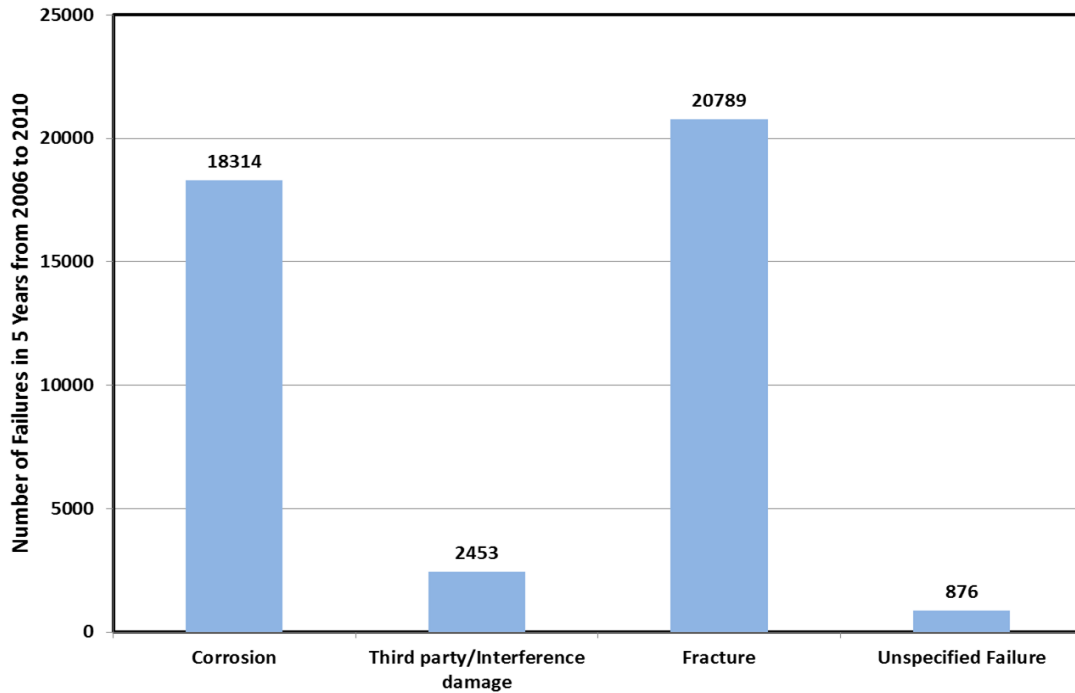
Figure 15 Number and type of failures recorded during the period 2006 to 2010 in iron and steel pipes in UK
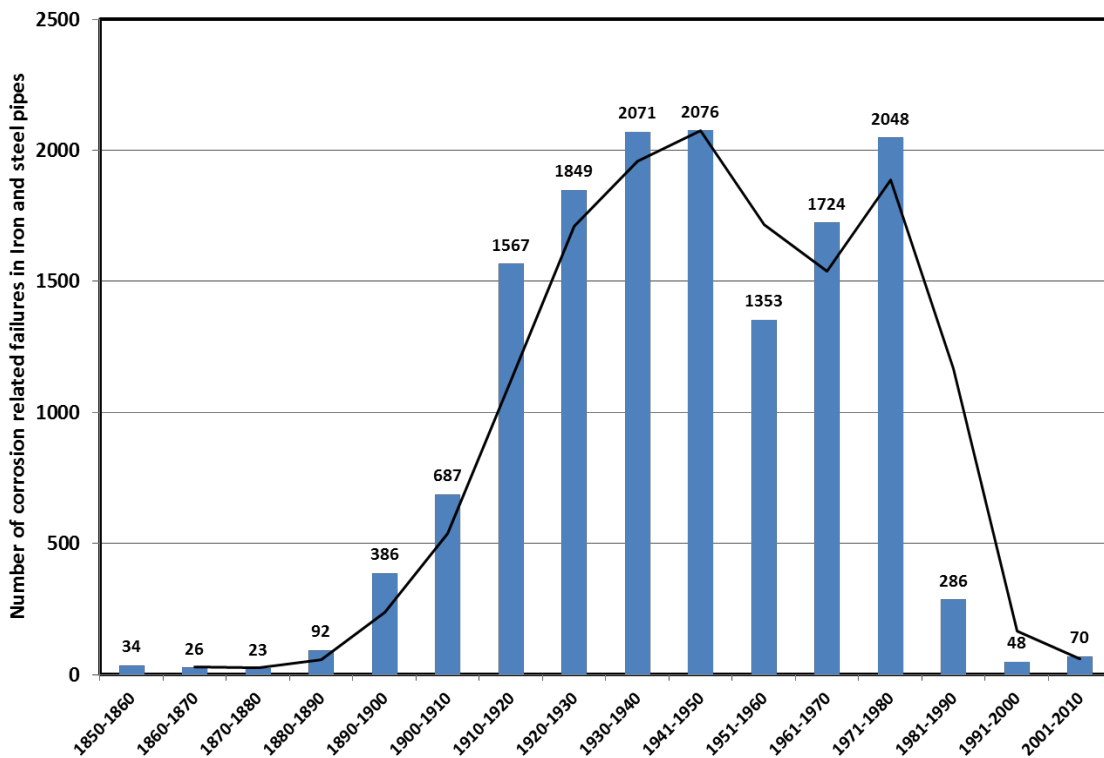
Figure 16 Number of external corrosion related failures noticed in the period 2006 to 2010 vs. the actual age of the pipes (both iron and steel).
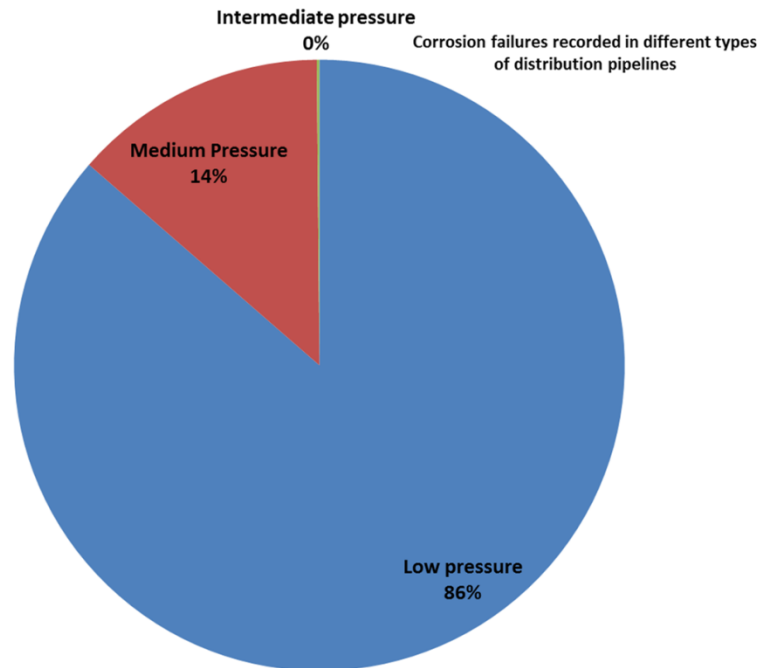
Figure 17 Type of distribution pipelines involved in external corrosion failures during the period 1850 - 2010

The main conclusions from the data presented in Figure 14, Figure 15, Figure 16, & Figure 17 are

- Pipe and pipe joints are the most susceptible area for failures in distribution pipeline network.
- External corrosion and fracture are the two principal causes for most of the failures experienced by distribution pipeline network.

6.2.1   Pipeline failure scenarios

The external corrosion failures are mostly associated with low pressure (<2bar) of the distribution pipeline network. Based on historical data presented in Figure 15, failures of the distribution pipe occur principally due to

- Corrosion (External)
- Fracture

Failure scenarios due to fracture are not considered in the current study. Current distribution risk models use the location and distance of the pipe from the nearby property to analyse the consequences due to corrosion and fracture. The distance from the nearby property is critical as the potential of gas leak due to corrosion of distribution pipelines into the building and potential impacts of immediate ignition are recorded as incidents.

The probability of ignition of gas is determined from analysis of historical data, selected as appropriate for the operating pressure and size of the pipeline. Generally the historical probability of ignition of gas released from distribution pipeline is low (of the order of 0.1 or less) [10]. For more details of quantification of

explosion risk, quantification of fire risk and details of Hazards posed by distribution pipelines refer elsewhere [10].

6.2.2 Scenarios considered in the assessment

The impact of 0.25% to 5% O_2 in high concentration of CO_2 and H_2S at maximum temperature of 38^0C has been considered in the corrosion rate calculations and it was found that indicative corrosion rates are very low. Corrosion might occur only for limited period during conditions when water may enter the pipes from external sources or from leakage joints in low pressure mains. The results clearly shows increasing oxygen content increases the corrosion rate by a factor of four or five for medium to high pressure systems.

Table 10 summarises the scenarios considered in the assessment and is primarily focussed on the internal corrosion of pipelines due to the injection of bio gas into the gas distribution system.

Consequence of failure was estimated, assuming a pipeline corrodes internally and causes a gas leak. The same risk applies to the external corrosion failures and scenarios due to external corrosion are not included in the assessment. The main criteria considered in the assessment of the scenarios are the distance of the pipeline from nearby occupied property, the presence of cellars or other voids and whether open ground allows gas to escape before ignition. Analysis of historical failures indicates that gas explosions are associated with fractured pipes that allow a large release of gas wheras corrosion holes release relatively small amounts of gas that result in a public report of the smell of gas and a call out to investigate.

Thus, the consequence of failure due to internal corrosion of distribution pipe will be low regardless of its location since it is unlikely to cause an explosion.

Table 10 Scenarios considered in the risk assessment

Scenarios	Location of the main		Consequences	Consequence of Failure
	Pipe within 10 metres of nearby property	**Pipe more than 10 metres from property**		
Corrosion (Internal) of Iron and steel pipes	Yes	No	Likely to be reported smell of gas requiring call out. Repair will be required as below. No injuries or fatalities.	**Low**
Corrosion (Internal) of Iron and steel pipes	No	Yes	Can lead to increase in cost of repairs, inspection, may close roads, traffic disruption, business disruption, loss of supply while repairing. No injuries or fatalities.	**Low**

7 Risk assessment Result

The overall risk assessment results for the distribution steel pipe are presented in Table 11.

Table 11 Risk assessment Result

Component material	Probability of Failure	Consequence of Failure	Overall Risk
Iron or steel Pipe within 10 metres from nearby property	**Low**	**Low**	**Low**
Iron or steel pipe not nearby property more than 10 metres from nearby property	**Low**	**Low**	**Low**

The overall risk is estimated to be low regardless of the location of the pipe since the volumes of gas released from a corrosion hole will be small and thus the failure will be detected before an incident occurs particularly if the pipe is in the vicinity of an occupied property. This conclusion is supported by recent HSE sponsored research into the effects of corrosion on buried domestic LPG pipework [14]. The research concluded that:

"The most important characteristics of such corrosion leaks for this study are that they are generally small in size, and that they develop progressively; there is no experience of sudden large leaks arising from this cause. " and that:

"the nature of corrosion leaks, which develop progressively, mean that there should be a high likelihood of detecting any developing accumulation of LPG in a building by smell long before a flammable concentration is reached. "

Most of the European countries already use oxygen levels of up to 1%, see Appendix Table A 5 and so far no reported failures in public domain. The calculated corrosion rate from the current study at 1% O_2 level for low pressure distribution system (75mbar) at maximum GS(M)R limit conditions is less than 0.1mm/y. Results show that increase in O_2 % levels due to injection of NCS gas is not expected to present significant increased risks to the distribution pipeline network system.

8 Conclusions

1. The overall internal corrosion risk associated with the iron and steel pipe due to the injection of biogas is low. No credible damage mechanism was identified that can cause threat to the integrity of the steel pipes used in the distribution network system.

2. The probability of failure due to the internal corrosion of the iron and steel pipes used in the distribution system is low; this is attributed to the relatively low concentrations of many compounds present in both NCS gas and current natural gas.

3. The effect of increasing oxygen concentration is strongly related to the system pressure. It has little effect on corrosion rates for low pressure (75mbar) distribution systems, whereas in medium and intermediate distribution pressure systems it causes corrosion rates to increase. This is since the increase in corrosion rates is driven by the oxygen partial pressure rather than the oxygen concentration. However, since the higher pressure systems are dehydrated then corrosion will be prevented by the absence of liquid water. Water ingress into medium and high pressure gas systems from adjacent water infrastructure is also extremely unlikely as the majority of water systems operate at pressures below that of the gas systems.

4. The overall risk is estimated to be low regardless of the pipe location. This is since the volume of gas released from a corrosion hole in a low pressure system will be insufficient to result in an incident. The consequence of failure will thus, be a public report of gas and a call out to investigate.

5. The injection of treated and purified biogas into the gas distribution network does not seem to present any additional risk to customers-provided that biogas originated from the four sources such as:

    *   Biogas from the anaerobic digestion of sewage sludge, farm waste, energy crops, food waste and bio methane after clean-up
    *   Landfill gas – raw and processed
    *   Coal mine, coal bed and shale gas – raw and processed
    *   Synthetic natural gas (SNG) from the gasification of biogas, biomass or coal

9   Reference Documents

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Appendix A   NCS gas constituents

A.1   NCS GAS Quality Data

Table A 1 Concentration ranges for contaminants in raw and processed biogas from waste water, farms and energy crops

Contaminant	Concentration Range Raw biogas	Processed biogas
Methane	40 -- 55 mol%	75 – 99 mol%
CO_2	15 – 55 mol%	0.2 – 25 mol%
H_2S	0 – 45600 mg/m^3	0 – 10mg/m^3
Total Sulphur	Dominated by H_2S	
O_2	0 – 6 mol%	0 – 2 mol%
Moisture	saturated	32 mg/m^3
Siloxanes	0 – 400 mg/m^3	<1 – 48 mg/m^3
Organic Halides	0 – 11.5 mg/m^3	0 – 7.4 mg/m^3
Micro-Organisms	0 – 280 cfu/m^3	0 – 1.37 x 10^5 cfu/m^3
Terpenes	0 – 230 mg/m^3	
Aldehydes & Keytones	0 – 1.22 mg/m^3	
Ammonia NH_3	0.6 – 50 mg/m^3	
Arsenic	0 – 0.5 µg/m^3	
Total pesticides & Pharmaceuticals	0 – 0.001 mg/m^3	Not detected

Table A 2 Concentration ranges for contaminants in raw and processed landfill gas from all waste types

Contaminant	Concentration Range Raw biogas	Processed biogas
Methane	22.5 -- 70 mol%	88.3 – 99 mol%
CO_2	9.2 – 60 mol%	1 – 4.7 mol%
H_2S	0 – 15200 mg/m^3	0 – 15 mg/m^3
Total Sulphur	0 – 200 mg/m^3	No data
O_2	0 – 10 mol%	0 – 2 mol%
Moisture	0 -- saturated	No data
Total Siloxanes	0 – 8000 mg/m^3	< 20 mg/m^3
Total Organic Halides	0 – 842 mg/m^3	0.03 – 3 mg/m^3
Micro-Organisms	No data	
Mercury	0.13 – 9.5 µg/m^3	
Arsenic	0.04 – 430 µg/m^3	No data

Carbonyls	Upto 42 mg/m^3	
Furans	<10 – 6200 µg/m^3	
Terpenes	Upto 272 mg/m^3	
Benzene	70ppb – 21.2 ppm	30ppb

Table A 3 Concentration ranges for contaminants in raw and processed SNG from gasification of biogas, biomass and coal

Contamination	Concentration range Raw Gas	Processed gas
CH_4	0 – 81.9 mol%	10 – 96 mol%
CO_2	8.3 – 49.4 mol%	0.47 – 8.9 mol%
N_2	7-8 mol%	0.5 – 3 mol%
H_2S	Not detected	No data
Total Sulphur	Not detected	No data
H_2	4 -13.2 mol%	0.5 – 8 mol%
Carbon monoxide (CO)	0 -- 0.5 mol%	0.01 – 0.06 mol%
Moisture	All data us on a dry basis	0 – 1268 mg/m^3
Hydrogen chloride (HCl) Hydrogen Fluoride	Not detected	No data
Total tar	17mg/m^3	No data

Table A 4 Concentration ranges for contaminants in raw coal mine, coal bed and shale gas

Contamination	Concentration range Raw Gas
CH_4	25 – 99.2 mol%
CO_2	0.6 – 27.5 mol%
N_2	0.05 -- 59 mol%
H_2S	5 – 8 mg/m^3
Total Sulphur	Only H_2S data
O_2	0 -- 17 mol%
Moisture	All data us on a dry basis
Organic Halides	Not detected
HCL/HF	Not detected
Micro organisms	No data

A.2 Technical specification in European countries

Table A 5 Technical specification applied in european countries

	Unit	France		Germany (1)		Switzerland		Sweden	Austria	Netherlands
		H gas	L gas	H gas	L gas	Unlimited Injection	Limited Injection			
Wobbe Index	kWh/Nm³	13.64-15.7	12.01-13.06	12.8-15.7	10.5-13.0	13.3-15.7		-	13.3-15.7	-
	MJ/Nm³	48.24-56.52 (higher)	42.48-46.80 (higher)	46.1-56.5 (higher)	37.8-46.8 (higher)	47.9-56.5	-	Type A (2): 44.7-46.4 (lower) Type B (2): 43.9-47.3 (lower)	47.7-56.5 (higher)	43.46-44.41 (higher)
Gross calorific value	kWh/Nm³	10.7-12.8	9.5-10.5	8.4-13.1		10.6-13.1		-	10.7-12.8	8.8-10.8
	MJ/Nm³	38.52-46.08 (higher)	34.2-37.8 (higher)	30.2-47.2		38.5-47.2	-	-	38.5-46.0	31.6-38.7
Methane	vol %	-		-		> 96	> 50	> 97 (2)	96	-
CO₂		< 2.5 mol % (Flexibilities exist for specific conditions e.g. in Lille: <11%)		< 6 vol %		< 6 vol %		< 4 vol % (3)	< 3 vol %	< 6 mol % < 10-10.3 % for regional grid
CO	mol %	< 2		-		< 0.5		-	-	< 1
O₂	vol %	< 100 ppmv (flexibilities exist for specific conditions e.g. in Lille: <3%)		< 0.5 (<3 if dry gas)		< 0.5		< 1	< 0.5	< 0.5
H₂	vol %	< 6		< 5		< 4		-	< 4	< 12
H₂S	mg/Nm³	< 5 (H₂S + COS)		< 5		< 5		< 10 ppm (4)	< 5	<|5
Mercaptans (RSH)	mg/Nm³	< 6		< 16		< 5 ppmv		-	< 6	< 10
Total sulphur	mgS/Nm³	< 30		< 30		< 30		< 23	< 10	< 45

A.3 Input data for corrosion Rate Calculations

Table A 6 Parameters considered in the corrosion rate calculations

	Total Pressure (psi),	P_{co2} (psi), 25 mol% CO_2	P_{H2S} (psi), 15 mg/m3	% O_2 levels	P_{O2} (psi)	deg C	pH	pH used in CR calculations	Corrosion Rate, mills/py	Corrosion Rate, mm/py
Case1, 15mg/m3 H2S 25 mol% CO2, 75mbar total pressure, Temperature 38C	1.08	0.27	0.0000162	0.25	0.0027	38	7.1	6	2.78	0.07
	1.08	0.27	0.0000162	0.5	0.0054	38	7.1	6	2.79	0.07
	1.08	0.27	0.0000162	0.75	0.0081	38	7.1	6	2.80	0.07
	1.08	0.27	0.0000162	1	0.0108	38	7.1	6	2.81	0.07
	1.08	0.27	0.0000162	1.25	0.0135	38	7.1	6	2.82	0.07
	1.08	0.27	0.0000162	1.5	0.0162	38	7.1	6	2.82	0.07
	1.08	0.27	0.0000162	1.75	0.0189	38	7.1	6	2.83	0.07
	1.08	0.27	0.0000162	2	0.0216	38	7.1	6	2.84	0.07
	1.08	0.27	0.0000162	2.25	0.0243	38	7.1	6	2.85	0.07
	1.08	0.27	0.0000162	2.5	0.027	38	7.1	6	2.86	0.07
	1.08	0.27	0.0000162	2.75	0.0297	38	7.1	6	2.87	0.07
	1.08	0.27	0.0000162	3	0.0324	38	7.1	6	2.88	0.07
	1.08	0.27	0.0000162	3.25	0.0351	38	7.1	6	2.89	0.07
	1.08	0.27	0.0000162	3.5	0.0378	38	7.1	6	2.90	0.07
	1.08	0.27	0.0000162	3.75	0.0405	38	7.1	6	2.91	0.07
	1.08	0.27	0.0000162	4	0.0432	38	7.1	6	2.92	0.07
	1.08	0.27	0.0000162	4.25	0.0459	38	7.1	6	2.93	0.07
	1.08	0.27	0.0000162	4.5	0.0486	38	7.1	6	2.94	0.07
	1.08	0.27	0.0000162	4.75	0.0513	38	7.1	6	2.95	0.07
	1.08	0.27	0.0000162	5	0.054	38	7.1	6	2.96	0.08

GL Noble Denton

	29	7.25	0.000435	0.25	0.0725	38	5.7	5.7	2.27	0.06
	29	7.25	0.000435	0.5	0.145	38	5.7	5.7	2.55	0.06
	29	7.25	0.000435	0.75	0.2175	38	5.7	5.7	2.81	0.07
	29	7.25	0.000435	1	0.29	38	5.7	5.7	3.08	0.08
	29	7.25	0.000435	1.25	0.3625	38	5.7	5.7	3.33	0.08
	29	7.25	0.000435	1.5	0.435	38	5.7	5.7	3.58	0.09
	29	7.25	0.000435	1.75	0.5075	38	5.7	5.7	3.82	0.10
	29	7.25	0.000435	2	0.58	38	5.7	5.7	4.06	0.10
	29	7.25	0.000435	2.25	0.6525	38	5.7	5.7	4.29	0.11
2 bar	29	7.25	0.000435	2.5	0.725	38	5.7	5.7	4.52	0.11
	29	7.25	0.000435	2.75	0.7975	38	5.7	5.7	4.74	0.12
	29	7.25	0.000435	3	0.87	38	5.7	5.7	4.95	0.13
	29	7.25	0.000435	3.25	0.9425	38	5.7	5.7	5.16	0.13
	29	7.25	0.000435	3.5	1.015	38	5.7	5.7	5.36	0.14
	29	7.25	0.000435	3.75	1.0875	38	5.7	5.7	5.56	0.14
	29	7.25	0.000435	4	1.16	38	5.7	5.7	5.75	0.15
	29	7.25	0.000435	4.25	1.2325	38	5.7	5.7	5.93	0.15
	29	7.25	0.000435	4.5	1.305	38	5.7	5.7	6.11	0.16
	29	7.25	0.000435	4.75	1.3775	38	5.7	5.7	6.28	0.16
	29	7.25	0.000435	5	1.45	38	5.7	5.7	6.45	0.16
	101	25.25	0.001515	0.25	0.25	38	5.1	5.1	4.08	0.10
7 bar	101	25.25	0.001515	0.5	0.505	38	5.1	5.1	6.15	0.16
	101	25.25	0.001515	0.75	0.7575	38	5.1	5.1	8.10	0.21
	101	25.25	0.001515	1	1.01	38	5.1	5.1	9.95	0.25

	101	25.25	0.001515	1.25	1.2625	38	5.1	5.1	11.70	0.30
	101	25.25	0.001515	1.5	1.515	38	5.1	5.1	13.36	0.34
	101	25.25	0.001515	1.75	1.7675	38	5.1	5.1	14.92	0.38
	101	25.25	0.001515	2	2.02	38	5.1	5.1	16.38	0.42
	101	25.25	0.001515	2.25	2.2725	38	5.1	5.1	17.75	0.45
	101	25.25	0.001515	2.5	2.525	38	5.1	5.1	19.02	0.48
	101	25.25	0.001515	2.75	2.7775	38	5.1	5.1	20.19	0.51
	101	25.25	0.001515	3	3.03	38	5.1	5.1	21.26	0.54
	101	25.25	0.001515	3.25	3.2825	38	5.1	5.1	22.23	0.56
	101	25.25	0.001515	3.5	3.535	38	5.1	5.1	23.11	0.59
	101	25.25	0.001515	3.75	3.7875	38	5.1	5.1	23.89	0.61
	101	25.25	0.001515	4	4.04	38	5.1	5.1	24.58	0.62
	101	25.25	0.001515	4.25		38	5.1	5.1		
	203	50.75	0.003045	0.25	0.5075	38	4.8	4.8	6.54	0.17
	203	50.75	0.003045	0.5	1.015	38	4.8	4.8	10.31	0.26
	203	50.75	0.003045	0.75	1.5225	38	4.8	4.8	13.71	0.35
	203	50.75	0.003045	1	2.03	38	4.8	4.8	16.72	0.42
	203	50.75	0.003045	1.25	2.5375	38	4.8	4.8	19.35	0.49
14 bar	203	50.75	0.003045	1.5	3.045	38	4.8	4.8	21.60	0.55
	203	50.75	0.003045	1.75	3.5525	38	4.8	4.8	23.46	0.60
	203	50.75	0.003045	2	4.06	38	4.8	4.8	24.94	0.63
	203	50.75	0.003045	2.25	4.5675	38	4.8	4.8	26.04	0.66
	203	50.75	0.003045	2.5	5.075	38	4.8	4.8	26.75	0.68
	203	50.75	0.003045	2.75	5.5825	38	4.8	4.8	27.08	0.69
	203	50.75	0.003045	3	6.09	38	4.8	4.8	27.03	0.69

	203	50.75	0.003045	3.25	6.5975	38	4.8	4.8		
	203	50.75	0.003045	3.5	7.105	38	4.8	4.8		
	203	50.75	0.003045	3.75	7.6125	38	4.8	4.8		

	Total Pressure (psi),	P_{co2} (psi), 2 mol% CO_2	P_{H2S} (psi), 5 mg/m3	% O_2 levels	P_{O2} (psi)	deg C	pH	pH used in CR calculations	Corrosion Rate, mills/py	Corrosion Rate, mm/py
Case 2, 5mg/m3 H2S 2 mol% CO2, 75mbar total pressure, Temperature 38C	1.08	0.0216	0.0000054	0.25	0.0027	38	7	6	1.86	0.05
	1.08	0.0216	0.0000054	0.5	0.0054	38	7	6	1.88	0.05
	1.08	0.0216	0.0000054	0.75	0.0081	38	7	6	1.91	0.05
	1.08	0.0216	0.0000054	1	0.0108	38	7	6	1.93	0.05
	1.08	0.0216	0.0000054	1.25	0.0135	38	7	6	1.96	0.05
	1.08	0.0216	0.0000054	1.5	0.0162	38	7	6	1.98	0.05
	1.08	0.0216	0.0000054	1.75	0.0189	38	7	6	2.01	0.05
	1.08	0.0216	0.0000054	2	0.0216	38	7	6	2.03	0.05
	1.08	0.0216	0.0000054	2.25	0.0243	38	7	6	2.06	0.05
	1.08	0.0216	0.0000054	2.5	0.027	38	7	6	2.08	0.05
	1.08	0.0216	0.0000054	2.75	0.0297	38	7	6	2.11	0.05
	1.08	0.0216	0.0000054	3	0.0324	38	7	6	2.13	0.05
	1.08	0.0216	0.0000054	3.25	0.0351	38	7	6	2.15	0.05
	1.08	0.0216	0.0000054	3.5	0.0378	38	7	6	2.18	0.06
	1.08	0.0216	0.0000054	3.75	0.0405	38	7	6	2.20	0.06
	1.08	0.0216	0.0000054	4	0.0432	38	7	6	2.23	0.06
	1.08	0.0216	0.0000054	4.25	0.0459	38	7	6	2.25	0.06

	1.08	0.0216	0.0000054		0.0486	38	7	6	**2.28**	**0.06**
	1.08	0.0216	0.0000054		0.0513	38	7	6	**2.3**	**0.06**
	1.08	0.0216	0.0000054		0.054	38	7	6	**2.33**	**0.06**
2 bar	29	0.58	0.000145	0.25	0.0725	38	6.8	6	**2.61**	**0.07**
	29	0.58	0.000145	0.5	0.145	38	6.8	6	**3**	**0.08**
	29	0.58	0.000145	0.75	0.2175	38	6.8	6	**3.37**	**0.09**
	29	0.58	0.000145	1	0.29	38	6.8	6	**3.74**	**0.09**
	29	0.58	0.000145	1.25	0.3625	38	6.8	6	**4.1**	**0.10**
	29	0.58	0.000145	1.5	0.435	38	6.8	6	**4.46**	**0.11**
	29	0.58	0.000145	1.75	0.5075	38	6.8	6	**4.81**	**0.12**
	29	0.58	0.000145	2	0.58	38	6.8	6	**5.15**	**0.13**
	29	0.58	0.000145	2.25	0.6525	38	6.8	6	**5.48**	**0.14**
	29	0.58	0.000145	2.5	0.725	38	6.8	6	**5.81**	**0.15**
	29	0.58	0.000145	2.75	0.7975	38	6.8	6	**6.13**	**0.16**
	29	0.58	0.000145	3	0.87	38	6.8	6	**6.45**	**0.16**
	29	0.58	0.000145	3.25	0.9425	38	6.8	6	**6.75**	**0.17**
	29	0.58	0.000145	3.5	1.015	38	6.8	6	**7.05**	**0.18**
	29	0.58	0.000145	3.75	1.0875	38	6.8	6	**7.34**	**0.19**
	29	0.58	0.000145	4	1.16	38	6.8	6	**7.63**	**0.19**
	29	0.58	0.000145	4.25	1.2325	38	6.8	6	**7.91**	**0.20**
	29	0.58	0.000145	4.5	1.305	38	6.8	6	**8.18**	**0.21**
	29	0.58	0.000145	4.75	1.3775	38	6.8	6	**8.45**	**0.21**
	29	0.58	0.000145	5	1.45	38	6.8	6	**8.7**	**0.22**
7 bar	101	2.02	0.000505	0.25	0.25	38	6.2	6	**2.20**	**0.06**

	101	2.02	0.000505	0.5	0.505	38	6.2	6	4.10	0.10
	101	2.02	0.000505	0.75	0.7575	38	6.2	6	5.92	0.15
	101	2.02	0.000505	1	1.01	38	6.2	6	7.67	0.19
	101	2.02	0.000505	1.25	1.2625	38	6.2	6	9.35	0.24
	101	2.02	0.000505	1.5	1.515	38	6.2	6	10.95	0.28
	101	2.02	0.000505	1.75	1.7675	38	6.2	6	12.46	0.32
	101	2.02	0.000505	2	2.02	38	6.2	6	13.96	0.35
	101	2.02	0.000505	2.25	2.2725	38	6.2	6	15.36	0.39
	101	2.02	0.000505	2.5	2.525	38	6.2	6	16.69	0.42
	101	2.02	0.000505	2.75	2.7775	38	6.2	6	17.95	0.46
	101	2.02	0.000505	3	3.03	38	6.2	6	19.14	0.49
	101	2.02	0.000505	3.25	3.2825	38	6.2	6	20.26	0.51
	101	2.02	0.000505	3.5	3.535	38	6.2	6	21.31	0.54
	101	2.02	0.000505	3.75	3.7875	38	6.2	6	22.29	0.57
	101	2.02	0.000505	4	4.04	38	6.2	6	23.20	0.59
	101	2.02	0.000505	4.25		38	6.2	6	23.91	0.61
14 bar	203	4.06	0.001015	0.25	0.5075	38	5.9	5.9	5.71	0.15
	203	4.06	0.001015	0.5	1.015	38	5.9	5.9	8.52	0.22
	203	4.06	0.001015	0.75	1.5225	38	5.9	5.9	11.58	0.29
	203	4.06	0.001015	1	2.03	38	5.9	5.9	14.40	0.37
	203	4.06	0.001015	1.25	2.5375	38	5.9	5.9	16.96	0.43
	203	4.06	0.001015	1.5	3.045	38	5.9	5.9	19.28	0.49
	203	4.06	0.001015	1.75	3.5525	38	5.9	5.9	21.30	0.54
	203	4.06	0.001015	2	4.06	38	5.9	5.9	23.18	0.59
	203	4.06	0.001015	2.25	4.5675	38	5.9	5.9	24.76	0.63

	Total Pressure (psi)	CO2 (psi)	H2S (psi)	% O2 levels	O2 (psi)	deg C	pH	pH	Corrosion Rate mills/py	Corrosion Rate
	203	4.06	0.001015	2.5	5.075	38	5.9	5.9	26.10	0.66
	203	4.06	0.001015	2.75	5.5825	38	5.9	5.9	27.18	0.69
	203	4.06	0.001015	3	6.09	38	5.9	5.9	28.03	0.71
	203	4.06	0.001015	3.25	6.5975	38	5.9	5.9	28.62	0.73
	203	4.06	0.001015	3.5	7.105	38	5.9	5.9	28.96	0.74
	203	4.06	0.001015	3.75	7.6125	38	5.9	5.9		

	Total Pressure (psi)	CO2 (psi)	H2S (psi)	% O2 levels	O2 (psi)	deg C	pH	Corrosion Rate mills/py	Corrosion Rate
Case3, 5mg/m3 H2S 25 mol% CO2, 7bar total pressure	101	25.25	0.00005	0.25	0.25	38	5.1	4.80	0.12
	101	25.25	0.00005	0.5	0.505	38	5.1	6.60	0.16
	101	25.25	0.00005	0.75	0.7575	38	5.1	8.26	0.20
	101	25.25	0.00005	1	1.01	38	5.1	9.80	0.24
	101	25.25	0.00005	1.25	1.2625	38	5.1	11.22	0.28
	101	25.25	0.00005	1.5	1.515	38	5.1	12.52	0.31
	101	25.25	0.00005	1.75	1.7675	38	5.1	13.70	0.34
	101	25.25	0.00005	2	2.02	38	5.1	14.76	0.37
	101	25.25	0.00005	2.25	2.2725	38	5.1	15.71	0.39
	101	25.25	0.00005	2.5	2.525	38	5.1	16.53	0.41
	101	25.25	0.00005	2.75	2.7775	38	5.1	17.23	0.43
	101	25.25	0.00005	3	3.03	38	5.1	17.82	0.45
	101	25.25	0.00005	3.25	3.2825	38	5.1	18.29	0.46
	101	25.25	0.00005	3.5	3.535	38	5.1	18.63	0.47

	101	25.25	0.00005	3.75	3.7875	38	5.1	**18.86**	**0.47**
	101	25.25	0.00005	4	4.04	38	5.1	**18.97**	**0.48**
	101	25.25	0.00005	4.25		38	5.1		**0.48**
14bar total pressure	203	50.75	0.001015	0.25	0.5075	38	4.8	**5.49**	**0.13**
	203	50.75	0.001015	0.5	1.015	38	4.8	**9.72**	**0.24**
	203	50.75	0.001015	0.75	1.5225	38	4.8	**13.69**	**0.34**
	203	50.75	0.001015	1	2.03	38	4.8	**17.41**	**0.44**
	203	50.75	0.001015	1.25	2.5375	38	4.8	**20.82**	**0.52**
	203	50.75	0.001015	1.5	3.045	38	4.8	**24.07**	**0.61**
	203	50.75	0.001015	1.75	3.5525	38	4.8	**27.07**	**0.68**
	203	50.75	0.001015	2	4.06	38	4.8	**29.71**	**0.75**
	203	50.75	0.001015	2.25	4.5675	38	4.8	**32.11**	**0.81**
	203	50.75	0.001015	2.5	5.075	38	4.8	**34.32**	**0.87**
	203	50.75	0.001015	2.75	5.5825	38	4.8	**36.24**	**0.92**
	203	50.75	0.001015	3	6.09	38	4.8	**37.91**	**0.96**
	203	50.75	0.001015	3.25	6.5975	38	4.8	**39.32**	**0.99**
	203	50.75	0.001015	3.5	7.105	38	4.8	**40.47**	**1.02**
	203	50.75	0.001015	3.75	7.6125	38	4.8	**41.37**	**1.05**
2 bar	29	7.25	0.000145	0.25	0.0725	38	5.7	**2.96**	**0.075**
	29	7.25	0.000145	0.5	0.145	38	5.7	**3.34**	**0.084**
	29	7.25	0.000145	0.75	0.2175	38	5.7	**3.71**	**0.09**
	29	7.25	0.000145	1	0.29	38	5.7	**4.07**	**0.1**
	29	7.25	0.000145	1.25	0.3625	38	5.7	**4.429**	**0.11**
	29	7.25	0.000145	1.5	0.435	38	5.7	**4.77**	**0.12**

29	7.25	0.000145	1.75	0.5075	38	5.7	**5.11**	**0.12**
29	7.25	0.000145	2	0.58	38	5.7	**5.45**	**0.13**
29	7.25	0.000145	2.25	0.6525	38	5.7	**5.77**	**0.14**
29	7.25	0.000145	2.5	0.725	38	5.7	**6.09**	**0.15**
29	7.25	0.000145	2.75	0.7975	38	5.7	**6.41**	**0.16**
29	7.25	0.000145	3	0.87	38	5.7	**6.71**	**0.17**
29	7.25	0.000145	3.25	0.9425	38	5.7	**7.01**	**0.17**
29	7.25	0.000145	3.5	1.015	38	5.7	**7.3**	**0.18**
29	7.25	0.000145	3.75	1.0875	38	5.7	**7.59**	**0.19**
29	7.25	0.000145	4	1.16	38	5.7	**7.87**	**0.19**
29	7.25	0.000145	4.25	1.2325	38	5.7	**8.14**	**0.2**
29	7.25	0.000145	4.5	1.305	38	5.7	**8.4**	**0.21**
29	7.25	0.000145	4.75	1.3775	38	5.7	**8.66**	**0.21**
29	7.25	0.000145	5	1.45	38	5.7	**8.91**	**0.22**
75mbar	1.08	0.27	0.0000054	0.25	0.0027	38	6	1.14	**0.02**
	1.08	0.27	0.0000054	0.5	0.0054	38	6	1.17	**0.02**
	1.08	0.27	0.0000054	0.75	0.0081	38	6	1.21	**0.03**
	1.08	0.27	0.0000054	1	0.0108	38	6	1.24	**0.03**
	1.08	0.27	0.0000054	1.25	0.0135	38	6	1.27	**0.03**
	1.08	0.27	0.0000054	1.5	0.0162	38	6	1.3	**0.03**
	1.08	0.27	0.0000054	1.75	0.0189	38	6	1.33	**0.03**
	1.08	0.27	0.0000054	2	0.0216	38	6	1.36	**0.03**
	1.08	0.27	0.0000054	2.25	0.0243	38	6	1.39	**0.03**
	1.08	0.27	0.0000054	2.5	0.027	38	6	1.42	**0.03**
	1.08	0.27	0.0000054	2.75	0.0297	38	6	1.46	**0.03**

	1.08	0.27	0.0000054	3	0.0324	38	6	1.49	0.03
	1.08	0.27	0.0000054	3.25	0.0351	38	6	1.52	0.03
	1.08	0.27	0.0000054	3.5	0.0378	38	6	1.55	0.03
	1.08	0.27	0.0000054	3.75	0.0405	38	6	1.58	0.04
	1.08	0.27	0.0000054	4	0.0432	38	6	1.61	0.04
	1.08	0.27	0.0000054	4.25	0.0459	38	6	1.64	0.04
	1.08	0.27	0.0000054	4.5	0.0486	38	6	1.67	0.04
	1.08	0.27	0.0000054	4.75	0.0513	38	6	1.7	0.04
	1.08	0.27	0.0000054	5	0.054	38	6	1.74	0.04

A.4 Screen shots of corrosion rate calculations

Figure 18 Scree shot of corrosion calculations using CORMOD excel file.

Probability of Pipeline Segment Leak

		Segment ID	Corrosion Rate Calculations for distribution Pipelines							☐ Select Pitting Model		
Coefficients	Mean Value for Uniform Corrosion	Standard Deviation for Uniform Corrosion	Random Variable for Uniform Corrosion	Mean Value for Pitting Corrosion	Standard Deviation for Pitting Corrosion	Random Variable for Pitting Corrosion	Species	Amounts of Species	Units	Year	Penetration Index	Cumulative Probability of Wall Penetration
Intercept	8.69876	0.93238	8.54221	107.67867	18.97649	0.00000	O_2	4.5675	psi	2012	0	0.000000%
$[O_2]$	19.71200	2.61018	21.93707	0.00000	0.00000	0.00000	pH	4.8	pH	2013	0	0.000000%
$[O_2]^2$	-0.59200	0.20000	-0.74348	0.00000	0.00000	0.00000	CO_2	50.75	psi	2014	0	0.000000%
pH	-1.30865	0.16690	-1.28499	-14.30555	3.06025	0.00000	H_2S	0.003045	psi	2015	0	0.000000%
$[CO_2]*[H_2S]$	0.04934	0.01308	0.03877	0.00000	0.00000	0.00000	CL	0.0607	%	2016	1	0.000000%
$[CO_2]*[O_2]$	-0.09646	0.02744	-0.03246	0.00000	0.00000	0.00000				2017	1	0.000000%
$[H_2S]$	0.00000	0.00000	0.00000	-50.73020	14.48949	0.00000				2018	1	0.000000%
$[H_2S]^2$	0.00000	0.00000	0.00000	18.10840	6.78587	0.00000				2019	1	0.000000%
$[H_2S]*[O_2]$	-4.74400	0.55050	-4.93346	0.00000	0.00000	0.00000				2020	1	0.100000%
$[O_2]*pH$	-2.22600	0.35580	-2.43727	0.00000	0.00000	0.00000				2021	1	0.400000%
$[CO_2]$	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000				2022	1	1.100000%
$[CO_2]^2$	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000				2023	1	2.300000%
CL	0.00000	0.00000	0.00000	23.24143	7.03979	0.00000				2024	1	4.900000%
										2025	1	9.200000%
	Uniform Corrosion			Pitting Corrosion						2026	1	16.300000%
Pressure, psig	Mils per Year Penetrated	Wall Thickness, in.		Mils per Year Penetrated	Wall Thickness, in.							
877	26.04041215	0.281		0	0.75					2027	1	25.900000%
	0.661426469									2028	1	39.800000%
										2029	1	56.900000%
Pipe Yield Strength, ksi	Pipe ID, in.			Number of Monte Carlo Iterations						2030	1	78.800000%
52	20			1000	Click for Probabilistic Analysis					2031	1	100.000000%
				Iterations Run								
				1000								

Table A 7 CorphupH calculator screen shot