National Grid Gas Transmission

# NOMs Methodology Validation Report

July 2019

Redacted Version

# Contents

# EXECUTIVE SUMMARY

We have undertaken extensive validation on the Sites and Pipelines models that allows total monetised risk (TMR) and proactive investment costs to be produced using the NOMs Methodology.

Our approach does not monetise the existing Asset Heath and Criticality bands. Risk is calculated from first principles using the prevailing asset defect rates as an input to the model. A consequence of this is that observed and measured defects cannot be used to test the outputs from the model. We have focused on the justification of the sensitive inputs to the model and have highlighted where these inputs have a material impact on monetised risk and future investment levels.

In summary, we are confident that the Sites and Pipelines are fully suitable for modelling the **relative** levels of monetised risk for use in monetised risk reporting and investment planning, if the same assumptions for without- and with- intervention analysis are used. An example of this is asset deterioration, where a higher/lower rate of deterioration will result in higher/lower values of intervention benefit.

In terms of modelling **absolute** levels of risk there is greater uncertainty at present, as assumptions need to be made for some sensitive input variables where there is immaturity in modelling monetised risk or limited historical failure and consequence data.

Environment risk appears to be relatively high when compared to Availability or Safety risk. Availability risk is currently biased towards risk at Exit points and further work to consider the wider impacts of wide-scale loss of supply would be beneficial.

Following a review of a draft validation report and discussions with Ofgem, we have now adopted a 1-in-20 demand scenario, based on Future Energy Scenarios (FES) 2021 base demands. The report describes how the Methodology was used to compare alternative, credible supply and demand scenarios.

# 1. INTRODUCTION

National Grid Gas Transmission (NGGT) has recently developed a new Methodology for Network Output Measures (the Methodology) which details how network risk expressed in monetary terms for use in the following applications (monetised risk):

- NGGT Rebasing RIIO-T1 targets through the Rewards and Incentives mechanism
- Undertaking Asset Health investment planning for RIIO-T2
- Setting targets for Asset Health (condition and risk) for RIIO-T2

Acceptability to Ofgem and stakeholders has been confirmed through the public consultation exercise, which concluded in May 2018, subject to validation of the modelling outputs.

This NOMs Methodology Validation Report describes:

- Which data inputs to the Methodology are important in quantifying monetised risk
  - This is discussed in Sections 3 and 4
- The impact that these sensitive inputs have on future monetised risk outputs reporting and on investment planning
  - This is discussed in Sections 4, 5 and 6
- How we have gained confidence to use these sensitive data inputs within the Methodology
  - This is discussed in Section 7

We have also undertaken significant testing to ensure that an appropriate supply and demand scenario is used and that the sensitivity of adopting alternative supply and demand scenarios is adopted. Following a review of our draft validation report by industry experts, and discussed with Ofgem, we have moved from an average high winter's day scenario to a 1-in-20 demand scenario, based on Future Energy Scenarios (FES) 2021 base demands. We have also adopted an approach based on variable capacity buyback assumptions, rather than the fixed assumptions used previously. This is discussed in Section 9.

The document should be read in the context of the NGGT Methodology for Network Outputs Measures and supporting documents[1]. All costs are based on a 2016/17 Price Base Date, unless otherwise stated.

# 2. VALIDATION APPROACH

## 2.1. PRINCIPLES

The NGGT NOMs Methodology has taken over 2 years to develop and is currently being used in support of our RIIO-T2 asset health investment plan. During this period of active model use many modelling issues have been identified and resolved and assumptions tested.

We have not attempted to monetise the Asset Heath (AH1 to AH5) and Criticality (C1 to C4) bands defined for the old Methodology and reported on throughout T1. Instead we have

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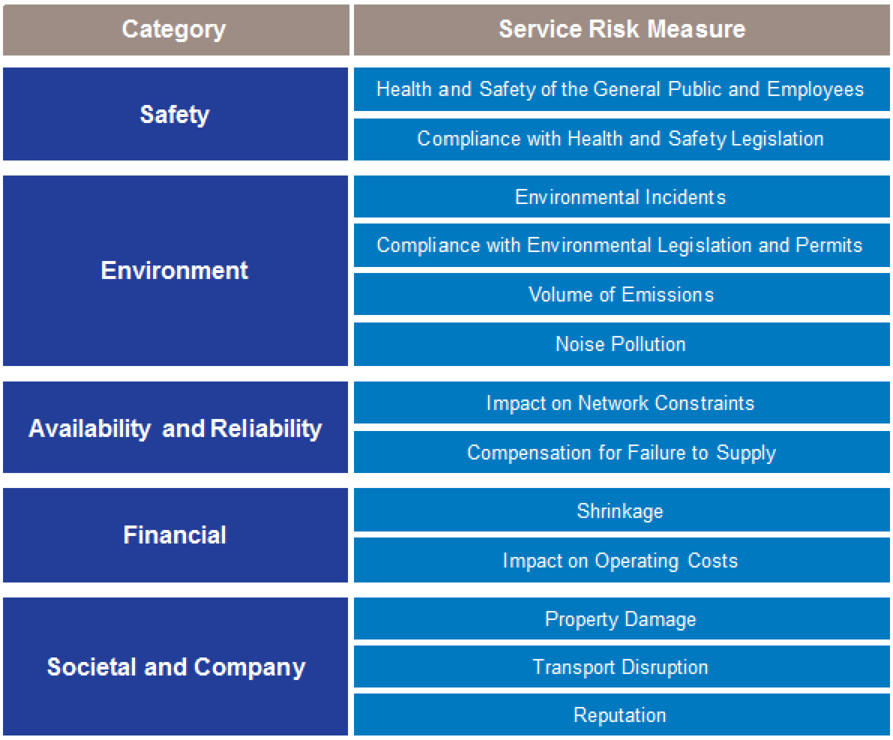
[1] Probability of Failure, Consequence of Failure and Service Risk Framework

quantified monetised risk from first principles, starting with the asset failure rate, assessing the consequences of failure and then valuing these consequences. Each asset has its individual monetised risk value which can we used to quantify and optimise the risk benefits delivered through investment.

There are two independent models that support the Methodology, Sites and Pipelines which roughly correspond to above- and below- ground assets:

- Asset Health Model
    - Both Sites and Pipelines models are built up from raw asset defect data, so there is no need to assign an Asset Heath grade to each asset before using it within the Methodology
- Criticality Model
    - Both Sites and Pipelines models use modelled consequences of failure, such as leaks or compressor trips, which are then valued using the Service Risk Framework (SRF)

We have assessed the contribution all elements of the SRF make towards calculating total monetised risk (TMR) and have outlined how all sensitive inputs have been derived, with references to source data. Where possible, the impact of these input data assumptions on actual NTS performance has been assessed (e.g. leak or vent prediction).



| Category | Service Risk Measure |
|---|---|
| Safety | Health and Safety of the General Public and Employees |
| | Compliance with Health and Safety Legislation |
| Environment | Environmental Incidents |
| | Compliance with Environmental Legislation and Permits |
| | Volume of Emissions |
| | Noise Pollution |
| Availability and Reliability | Impact on Network Constraints |
| | Compensation for Failure to Supply |
| Financial | Shrinkage |
| | Impact on Operating Costs |
| Societal and Company | Property Damage |
| | Transport Disruption |
| | Reputation |

Figure 1 – Service Risk Framework overview

For each significant SRF measure (Figure 1), we have described the calculation process leading to the reported TMR value and tested the sensitivity of each variable or coefficient used in the calculations. This allows us to efficiently identify sensitivity of input data in a model containing many hundreds of input variables and assumptions.

A core part of our validation approach were the independent expert reviews. Separate reviews were undertaken for the Sites and Pipelines models by industry experts to ensure that both the inputs to, and outputs from, the models are based on sound engineering principles and judgments (where required). The models are complex, and data to validate outputs is limited, and this sense-check was critical in giving us confidence that our models are fit-for-purpose.

## 2.2. DEFECT DATA MODEL INPUTS

Quality Assurance is carried out through our routine data management processes, which ensures, for example, that defects are linked to the correct asset and that outliers are removed. All base probability of failure (PoF) relationships are built up from these raw defect frequencies.

### 2.2.1. Sites

Defects data is taken from our AGI Asset Register (Ellipse) and aggregated into “pots” consisting of similar assets (with common failure modes). Several years’ worth of data is aggregated to determine the start PoF rate, by asset type, against which without-intervention deterioration curves are applied.

### 2.2.2. Pipelines

Corrosion and mechanical defects are recorded at a specific geographical location through In Line Inspection (ILI) pigging runs. These defects are assessed by asset integrity experts before being recorded in our Pipeline Asset Register (Uptime). Within our risk trading models, we allocate each corrosion and mechanical defect to a specific 12-metre pipe section which then acts as a seed for the Corrosion and Mechanical failure rate estimates, which ultimately could lead to a Leak or Rupture if unmitigated. Deterioration rates are then applied using industry-standard and modelled assumptions including the influence of pipeline characteristics, asset protection and localised environment.

### 2.2.3. Impact on calibration, testing and validation approach

As we have used raw defect data as the core input to our monetised risk assessments, we cannot use the same defects rates in the calibration and testing of our models. As there are limited numbers of actual failures on the NTS this has meant that confirming that the models are accurately predicting current and future performance and risk has been challenging.

The remainder of this report assumes that this source defect data is error-free and allocated to the correct asset (and by implication the correct asset grouping that influence the assumed deterioration).

NGGT has recently been recertified against ISO55001 which undertakes rigorous checks on core asset management processes, including the recording, prioritisation and rectification of defects. As such we believe that the assumption of error-free defect data is reasonable.

Data improvements in source systems will flow into the risk trading models and monetised risk calculations through ongoing data refreshes. Any source data improvement that has a material impact on monetised risk could potentially require application of a material changes mechanism (to be agreed with Ofgem).

## 2.3. KEY DEFINITIONS

There are several hundred different data sources feeding our risk trading models, ranging from base asset data, such as asset type, failure modes and operating pressures, to assumptions surrounding the proportions of failures that generate a consequence. There are also many routes through our risk maps, linking each asset to its monetised risk value. Much of this input data, and several of these routes through the risk map, contribute little to overall monetised risk. To simplify the validation process to only focus on inputs that contribute significantly to monetised risk, we have undertaken tests to identify the important input values and risk map routes. To achieve this, it is important to define the following terms:

- **Significant –** the monetised risk contribution of a specific SRF measure, when compared to total monetised risk (TMR), is large enough to require detailed validation of the contributing data inputs
- **Sensitive –** the contribution of a specific data input (variable or coefficient) uncertainty, to overall monetised risk or investment outcome uncertainty, is great enough to require detailed validation of the contributing data inputs

## 2.4. VALIDATION APPROACH SUMMARY

Based on the starting position described above the validation approach we have adopted is summarised in Figure 2 below. A brief description of each step is provided which is expanded up throughout the remainder of this document.

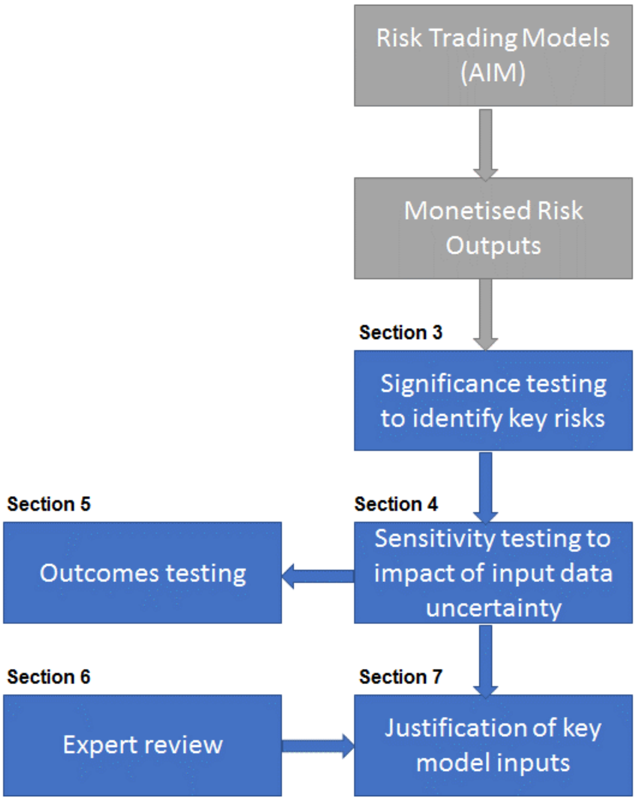


Figure 2 – Overview of our proposed top down validation approach

### 2.4.1. NOMs Models and NOMs Methodology

The NOMs Methodology will be validated in terms of the inputs and outputs from our NOMs risk trading models. These models have been developed in a specialist asset investment optimisation solution (Asset Investment Manager, AIM).

### 2.4.2. Significance of Service Risk Measures

All SRF measures will be tested for significance, based on their relative contribution to total monetised risk, both now and in the future (Without Investment). Whether SRF measures are deemed significant, further sensitivity testing will be carried out on the input variables and coefficients. No specific validation will be carried out for SRF measures that are deemed insignificant. Sources for all data sources and assumptions are described in the relevant supporting documents.

2041 was chosen as the final year of the planning period for significance testing as by 2051 Environment and Availability (Pipelines-only) risk are so large that they may potentially hide significance in the other service risk categories.

Thresholds for significance have been defined as per Table 1.

Table 1 Thresholds for assessing SRF measure significance

| TMR in Year | Materiality Threshold (% of TMR) |
|---|---|
| Current Date (2017) | ± 2% |
| Planning Period End Date (2041) | ± 1% |

These thresholds apply to each SRF measure. A measure is deemed to be significant if it contributes >2% to TMR in 2017 and >1% in 2041. A lower materiality threshold is necessary for the planning period end date as monetised risk values are considerably higher than the current year, as assets are deteriorating without proactive interventions being undertaken to control risk.

Significance testing results are presented in Section 3.

### 2.4.3. Sensitivity and resulting materiality of model inputs

Sensitivity testing will confirm which specific variables, coefficients (and associated calculations) have the potential for greatest impact on modelled monetised risk outputs. Where inputs are determined to be sensitive, further validation will be carried out, including checks on monetised risk and potentially future investment spend. This will indicate where input data uncertainty has a significant impact on future asset health investment spend levels, or on the mixture of investments between different asset types.

2051 was chosen as the final year for sensitivity testing as it is the accumulation of benefits to the end of the planning period under a no intervention scenario that defines which interventions are cost-beneficial and ultimately the value of the investment programme.

We will also conduct impact assessments, or materiality tests, on these key input variables to understand how variations impact on total monetised risk and/or investment levels.

Sensitivity testing results are presented in Section 4. Materiality tests on modelled outcomes are presented in Section 5).

### 2.4.4. Expert review

The expert review will confirm that the model outputs are sensible from an engineering and industry perspective. The scope of the expert review covers the Sites and Pipeline models independently and consider the following aspects of the NOMs Methodology data inputs and modelled outcomes:

- Comparison of predicted failure numbers with UK and international data sets
- Reassessment of failure mode assumptions and proportions
- Predicted numbers of fires and explosions
- Predicted fatalities and injuries

- Predicted loss of supply consequences, including the engineering approach used to monetise Availability risk[2]
- Pipeline corrosion modelling approach and assumptions

See Section 6 for a summary of the expert review outcomes.

### 2.4.5. Validation & justification of key model inputs

Evidence for validation or justification will be presented for all input variables and coefficients that are demonstrated to have a material impact on calculated monetised risk and on investment decision making.

- There are some inputs for there is no available data source which can be supported with evidence. These are where an assumption, based on input from asset experts, has been applied. In these cases, we will provide justification, including data sources, for the assumptions that have been used (e.g. leak hole size in Section 7.2.7)
- For inputs, which are uncertain and have a material impact on TMR and future investment these will be considered as future Methodology improvements
- Benchmarking will be carried out on model output where an equivalent asset exists for the gas distribution networks (GDNs). This will be limited to a comparison of Local Transmission System (LTS) pipelines and National Transmission System (NTS) pipelines at this stage

## 2.5. VALIDATION SCOPE EXCLUSIONS

Several model inputs, some which will be sensitive, cannot reasonably be validated for the following reasons:

- They are taken from a company data source for which there is no independent data source to validate against
- They are the industry default values which must be used, or no other reasonable values are available to be adopted with justification
- They are calculated from other input data sources

Examples of where data is taken from company systems include:

- The reported defects used to calculate the probability of failure in the Sites model, which are extracted from our works management systems[3].
- The number of corrosion and mechanical defects used to “seed”[4] the Pipelines probability of failure (PoF) assessments[5], which are measured from In Line Inspection (ILI) surveys.

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[2] Consequence of Failure Supporting Document, Section 6; Service Risk Framework Supporting Document, Section 6

[3] Probability of Failure Supporting Document, Section 5

[4] Observed metal loss defects from ILI are the seed/start points for modelled corrosion defect growth over time

[5] Probability of Failure Supporting Document, Section 4

Examples of where industry default values are used include:

- The HSE defined social value for a loss of life or major injury[6]
- The carbon valuations and carbon inflation figures issued by the Department of Business, Energy and Industrial Strategy (DBEIS)[7]
- Failure mode proportions used to allocate the correct consequences to defects in the Sites model[8]

# 3. SIGNIFICANCE OF SERVICE RISK MEASURES

This section describes the process taken to identify the most important routes through the risk maps which contribute most significantly to total monetised risk on the NTS (see Section 2.4.2). This allows the input data and assumptions having the greatest impact to be taken forward for sensitivity testing (Section 4).

Many of the SRF measure used in our current Methodology contribute little to TMR, either now (2017) or in the future without investment (assumed to be 2041 for this analysis, see Section 2.4.2). These SRF measures have been included in the Methodology for two reasons:

- They were included as placeholders, as they may be important in the future or used to test model sensitivity
- The low significance of these measures was not understood at the time the model was developed; if they are unlikely to become significant in the future they may be removed through future revisions of the Methodology (e.g. noise pollution)

It is important to note that all TMR values are annualised (total costs divided by modelled frequency). If a low frequency consequence occurred, then the costs could be many times higher than those presented (e.g. an explosion). Likewise, these valuations could encompass many individual events over a year (e.g. ESD vents).

## 3.1. SITES SIGNIFICANCE TESTS

The TMR in 2017 is dominated by Financial risk (costs of operating and maintaining the network). By 2041 all monetised risk values have increased as assets degrade without proactive interventions. TMR is now dominated by Environment risk in 2041, due to the combined impact of increased emissions volumes and carbon inflation.

Based on the materiality thresholds defined in Table 1, the following Sites SRF measures are deemed to be Significant and will be carried forward for sensitivity analysis.

**Table 2 – Sites. % of total monetised risk by SRF measure in 2017 and 2041**

| SRF Measure | SRF Category | 2017 | 2041 |
|---|---|---|---|
| Base asset maintenance costs* | Financial | 59% | 8% |

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[6] Service Risk Framework Supporting Document, Section 4.4
[7] Service Risk Framework Supporting Document, Section 5.6
[8] Consequence of Failure Supporting Document, Section 2.1, Appendix A & Appendix B

| SRF Measure | SRF Category | 2017 | 2041 |
|---|---|---|---|
| Emissions from routine asset maintenance & operation** | Environment | 27% | 9% |
| Value of a supply outage (includes direct capacity buyback & indirect compensation costs) | Availability | 6% | 5% |
| Cost of gas lost through routine asset maintenance & operation** | Financial | 4% | 0% |
| $CO_2$ Emissions resulting from asset failures | Environment | 2% | 55% |
| Reactive asset repair costs* | Financial | 1% | 12% |
| Reactive costs of repairing assets damaged by fire | Financial | 0% | 1% |
| Increased maintenance costs due to asset deterioration* | Financial | 0% | 4% |
| Cost of gas lost through asset failures | Financial | 0% | 3% |
| Category 4 environmental prosecution costs | Financial | 0% | 1% |

*****The private maintenance and repair costs are the product of the modelled defects rate and derived unit costs. These are based on best available information and as such will not be sensitivity tested

******Calibrated value – see Section 7.4

The Safety monetised risk is apparently low as fires or explosions causing death or injuries are high consequence, low probability events. For Sites, we assume that deaths resulting from fires can only apply to employees working on site at the time of the event. This assumption, combined with the very low probability of an explosion, means that the monetised risk of fatalities from Sites assets is small. However, safety is of paramount importance to NGGT and Its customers so we believe it is prudent to test these assumptions, regardless of apparent significance.

## 3.2. PIPELINES SIGNIFICANCE TESTS

TMR is dominated by Safety risk, predominantly due to the risk of fires and explosions caused by corrosion leaks in built up areas.

By 2041, all monetised risk values have grown significantly due to deterioration. This growth is due to increased corrosion rates on pipelines due to failure of cathodic protection systems when proactive replacements are not carried out. The model predicts that large numbers of corrosion leaks would appear (112 a year by 2041) causing increased gas emissions, more supply outages and a high risk of death or injury resulting from fires or explosions. Availability risk now has the highest risk value, due to loss of pipeline feeders impacting on the ability to supply gas, followed by Environment risk due to the loss of unburned gas through corrosion leaks.

Table 3 - Pipelines monetised risk by SRF measure in 2017 and 2041

| SRF Measure | SRF Category | 2017 | 2041 |
|---|---|---|---|
| Value of a fatality to society | Safety | 61% | 20% |
| Value of a major injury to society | Safety | 20% | 7% |
| $CO_2$ Emissions resulting from asset failures | Environment | 10% | 28% |
| Value of a supply outage (includes direct capacity buyback & indirect compensation costs) | Availability | 5% | 44% |
| Cost of gas lost through asset failures | Environment | 1% | 2% |

There is no significant Financial risk for Pipelines as costs of repair and rectification of primary and secondary pipelines assets are generally treated as proactive (risk-based) interventions and extend the life of the asset. This includes rectification of corrosion defects (through ILI digs) and maintenance of cathodic protection systems.

## 3.3. SIGNIFICANT ROUTES THROUGH RISK TRADING MODELS

Based on the Significance tests applied (Section 3), the following “routes” through the Sites and Pipelines risk trading models were chosen as having sufficient significance such that their component input variables should be considered for sensitivity testing:

- **Availability and Reliability**. Social value of supply outage – Pipelines only, as Sites supply outage risk is only sensitive to a single input variable within our risk trading models (see Section 3.3.1 below)
- **Carbon Emissions**. Social value of carbon emissions and the private costs of loss of gas (wholesale value of gas lost through emissions (these follow the same route through the risk map and will be modelled together) – Sites and Pipelines
- **Health and Safety**. Social value of a fatality and major injury (these follow the same route through the risk map and will be modelled together) – Sites and Pipelines

Sensitivity analysis will be undertaken by assigning likely maximum and minimum values for each selected data input and then recalculating the monetised risk value for the relevant SRF measure using these extreme values. Sensitivity analysis will identify which specific input values will be taken forward for detailed testing and validation.

The key for the figures presented in Sections 3.3.1 to 3.3.3 are shown in Figure 3.

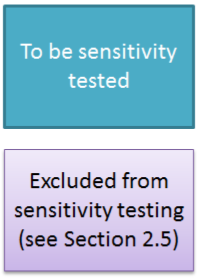

Figure 3 – Key for significance charts in Sections 3.3.1 to 3.3.3

### 3.3.1. Social value of supply outage

Figure 4 shows the risk mapping for the social value of supply outage in the Sites model.

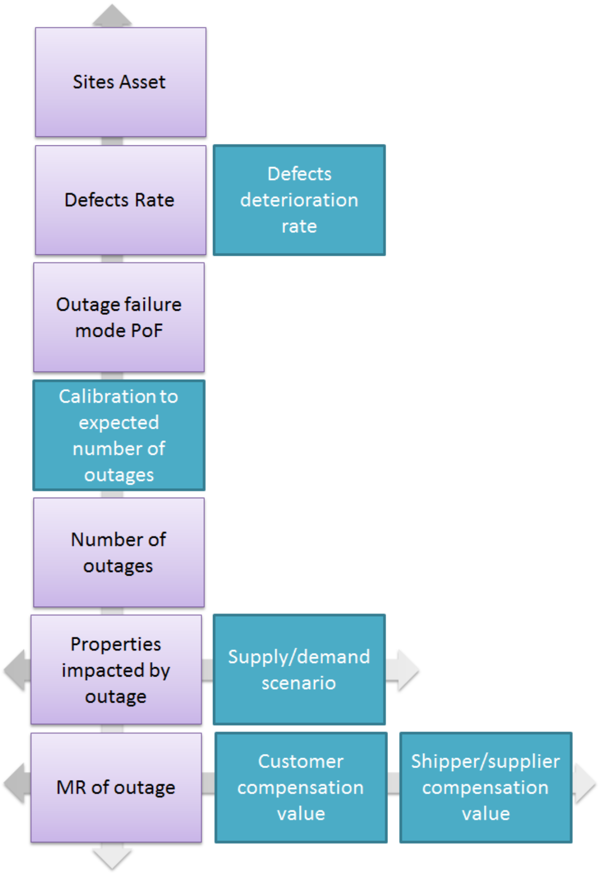

Figure 4 – Event tree for the Sites social value of a supply outage

Table 4 highlights which data inputs are believed to be the best available source currently to support the social value of a supply outage sensitivity analysis for Sites.

**Table 4 – Data inputs for the social value of a supply outage for Sites**

| Risk Node / Input Data | Taken from company systems, considered error free | Taken from published external data sources | Calculated value |
|---|---|---|---|
| Sites assets | X | | |
| Defects rate | X | | |
| Outage failure mode PoF | | X | |
| Number of outages | | | X |
| Properties impacted by outage | | | X |
| MR of outage | | | X |

Figure 5 shows the risk mapping for the private and social value of supply outage in the Pipelines model.

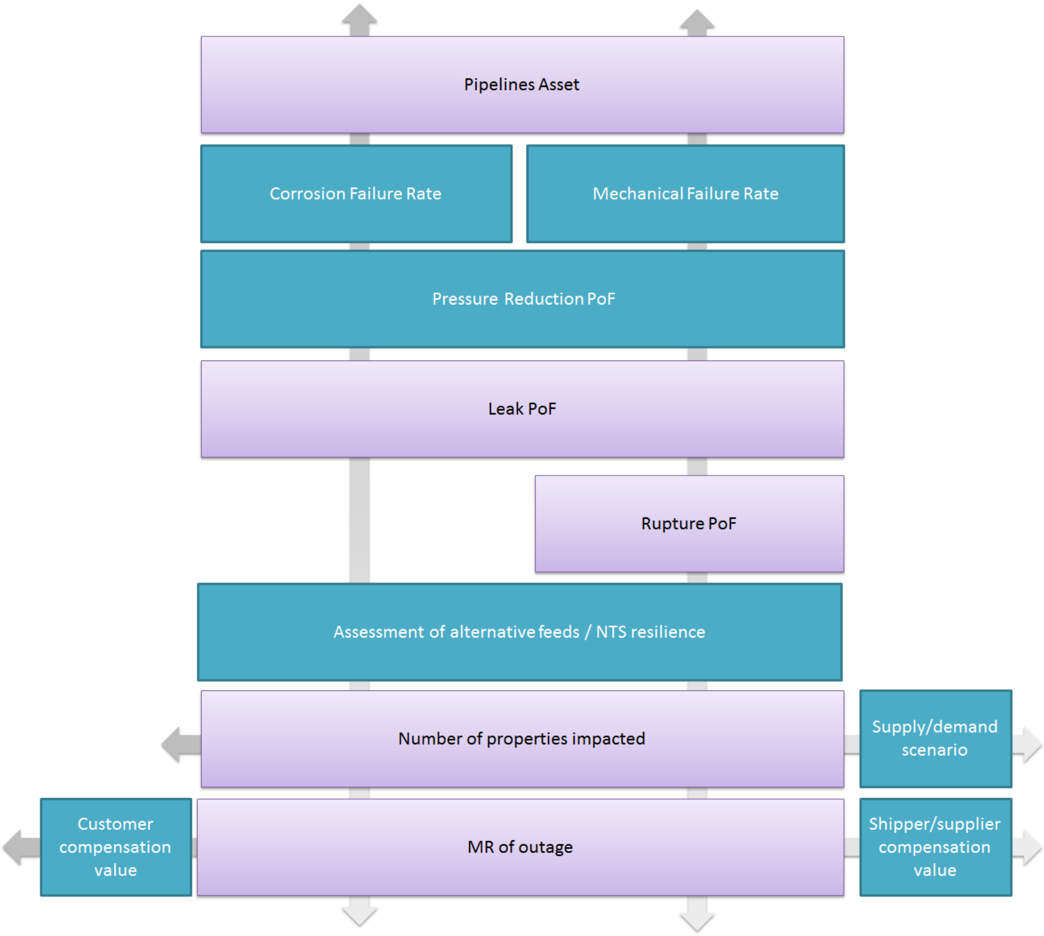

**Figure 5 - Event tree for the Pipelines social value of a supply outage**

Table 5 highlights which data inputs are believed to be the best available source currently to support the social value of a supply outage sensitivity analysis for Pipelines.

Table 5 - Data inputs for the social value of a supply outage for Pipelines

| Risk Node / Input Data | Taken from company systems, considered error free | Taken from published external data sources | Calculated value |
|---|---|---|---|
| Pipelines assets | X | | |
| Leak PoF | | X | |
| Rupture PoF | | X | |
| Number of properties impacted | | | X |
| MR of outage | | | X |

### 3.3.2. Social value of carbon emissions and the private costs of loss of gas

The social costs relate to the value of carbon lost through condition-related emissions (fuel gas emissions do not form part of the NOMs Methodology). The private costs, which relate to the average wholesale value of gas, are subsumed within shrinkage allowances but are included for completeness. Only condition-related failure modes are included but clearly leak, rupture and pressure reduction consequences will arise from non-condition failures, such as external interference.

Figure 6 shows the risk mapping for the social value of carbon emissions and the related private costs relating to the wholesale cost of gas for Sites.

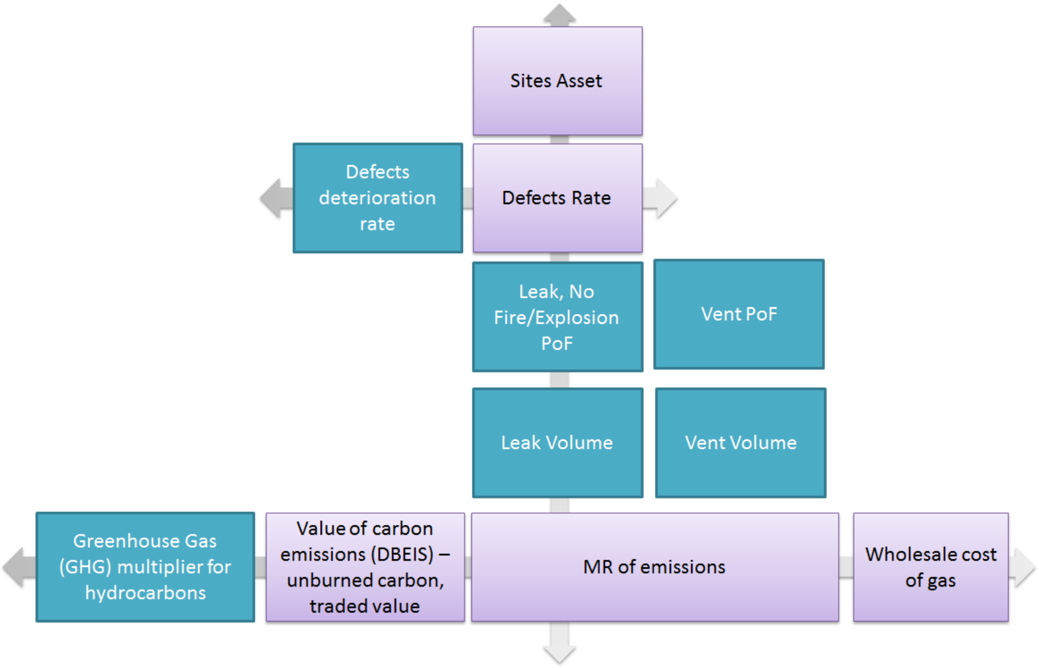

Figure 6 – Event tree for Sites social value of carbon emissions and private cost of loss of gas

Table 6 highlights which data inputs are believed to be the best available source currently to support the social value of carbon emissions and the private costs of loss of gas sensitivity analysis for Sites.

Table 6 - Data inputs for the social value of carbon emissions and the private costs of loss of gas for Sites

| Risk Node / Input Data | Taken from company systems, considered error free | Taken from published external data sources | Calculated value |
|---|---|---|---|
| Sites assets | X | | |
| Defects rate | X | | |
| Value of carbon emissions (DBEIS) | | X | |
| Wholesale cost of gas | | X | |
| Monetised risk of emissions | | | X |

Figure 7 shows the risk mapping for the social value of carbon emissions and the related private costs relating to the wholesale cost of gas for Pipelines.

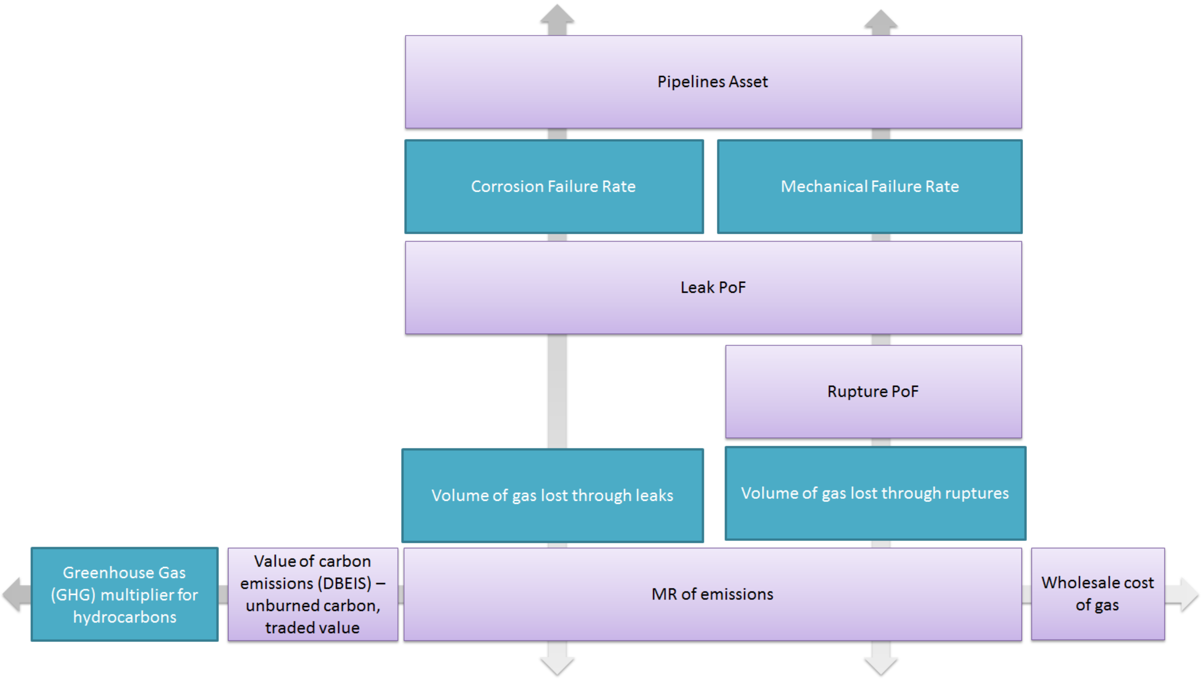

Figure 7 - Event tree for Pipelines social value of carbon emissions and private cost of loss of gas

Table 7 highlights which data inputs are believed to be the best available source currently to support the social value of carbon emissions and the private costs of loss of gas sensitivity analysis for Pipelines.

Table 7 - Data inputs for the social value of carbon emissions and the private costs of loss of gas for Pipelines

| Risk Node / Input Data | Taken from company systems, considered error free | Taken from published external data sources | Calculated value |
|---|---|---|---|
| Pipelines assets | X | | |
| Leak PoF | X | | |
| Rupture PoF | X | | |
| Value of carbon emissions (DBEIS) | | X | |
| Wholesale cost of gas | | X | |
| Monetised risk of emissions | | | X |

### 3.3.3. Social value of fatalities and major injuries

The social costs relate to the value of any loss of life or major injury caused by condition-related asset failure. It is worth noting that as per the Consequence of Failure Supporting document[9], that fires and explosions are treated differently for Sites and Pipelines.

For Sites:

- The safety impact of fires is constrained to NGGT sites and impacts on employees only
- The impact of explosions is not constrained to sites and the potential consequence is based on the assessed hazard zones for each site and the properties at risk (from GIS mapping data).
- Explosions can only occur based on the failure of assets which are present in a confined space, where the concentration of gas can build to a level that ignition would trigger an explosion.

For Pipelines:

- A hazard zone is calculated for each 12-metre pipe section based on the pipeline operating pressure and the number of properties within each hazard zones is estimated (from GIS mapping data)
- A worst-case scenario is assumed; that every potential gas release could result in a fire or explosion, each with its own probability of a consequence value assigned

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[9] Consequence of Failure Supporting Document, Section 3.2

A consequence of this assumption is that we would expect the Safety risk for Pipelines to be considerably higher than for Sites. However, Pipelines Safety consequences will only arise when there is a population at risk within the calculated hazard zones.

Figure 8 shows the risk mapping for the social value of fatalities and major injuries for Sites.

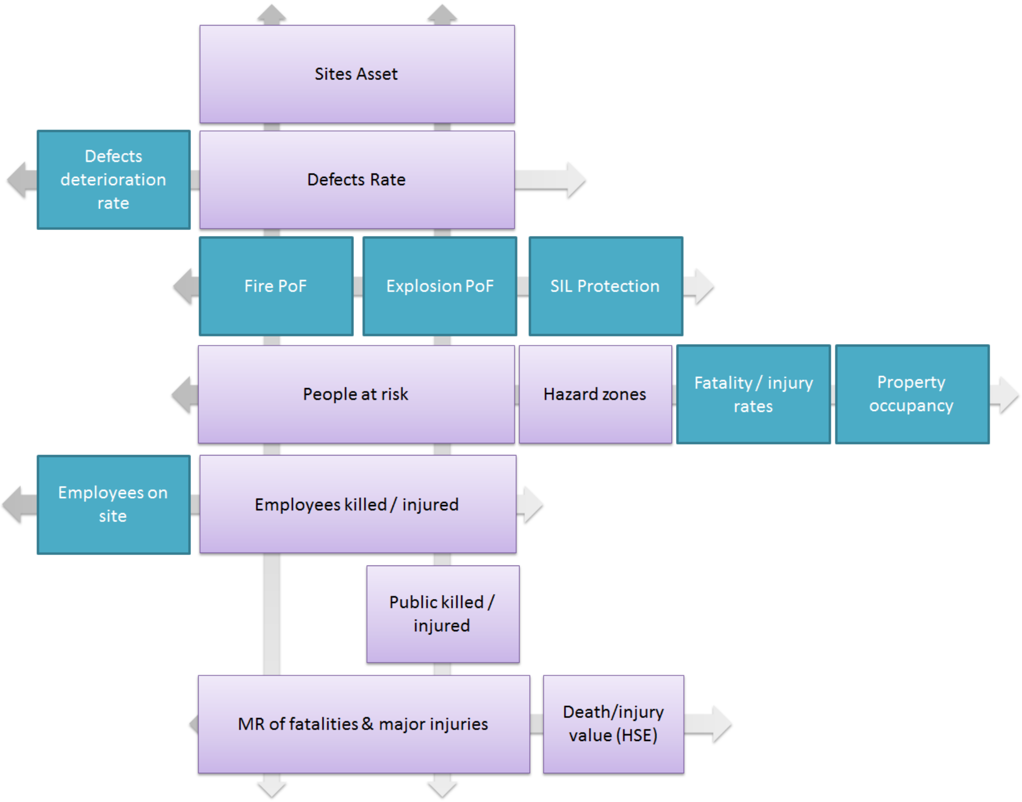

Figure 8 – Event tree for Sites social value of a fatality or major injury

Table 8 highlights which data inputs are believed to be the best available source currently to support the social value of fatalities and major injuries for Sites.

Table 8 - Data inputs for the social value of fatalities and major injuries for Sites

| Risk Node / Input Data | Taken from company systems, considered error free | Taken from published external data sources | Calculated value |
|---|---|---|---|
| Sites assets | X | | |
| Defects rate | X | | |
| People at risk | | | X |
| Hazard zones (distance from event source) | | X | |
| Employees killed/injured | | | X |
| Members of the public killed / injured | | | X |
| Value of a death / injury (HSE) | | X | |
| Monetised risk value of fatalities and major injuries | | | X |

Figure 9 shows the risk mapping for the social value of fatalities for Pipelines.

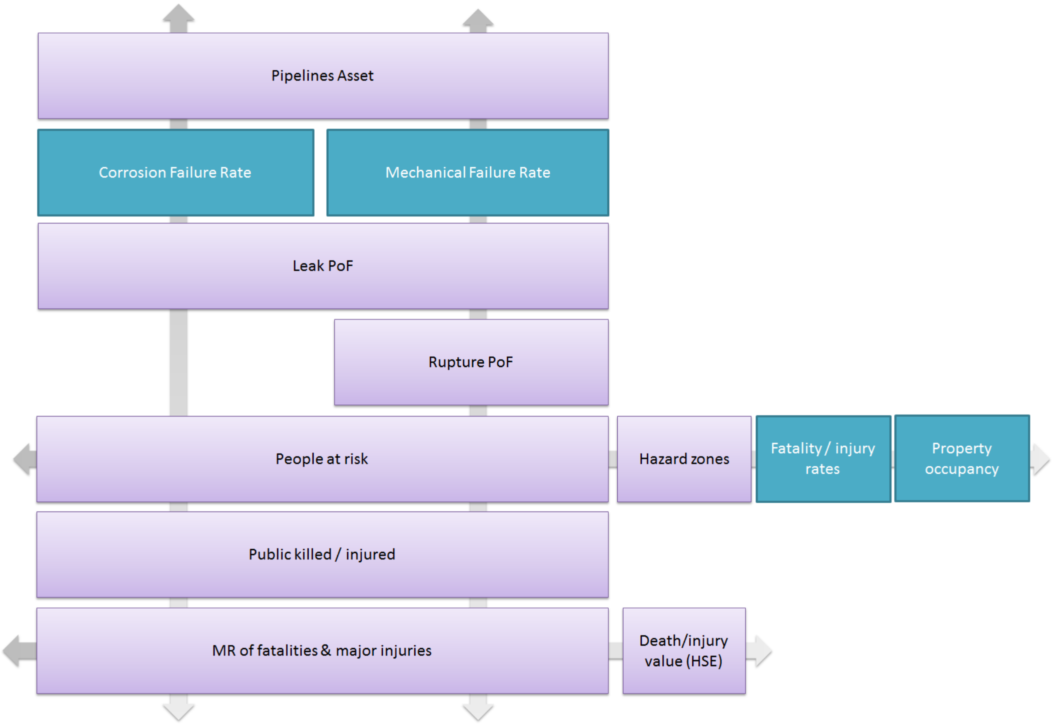

Figure 9 - Event tree for Pipelines social value of a fatality or major injury

Table 9 highlights which data inputs are believed to be the best available source currently to support the social value of fatalities and major injuries for Pipelines.

**Table 9 – Data inputs for the social value of fatalities and major injuries for Pipelines**

| Risk Node | Taken from company systems, considered error free | Taken from published external data sources | Calculated value |
|---|---|---|---|
| Pipelines assets | X | | |
| Leak PoF | | X | |
| Rupture PoF | | X | |
| People at risk | | | X |
| Hazard zones (distance from event source) | | X | |
| Members of the public killed / injured | | | X |
| Value of a death / injury (HSE) | | X | |
| Monetised risk value of fatalities and major injuries | | | X |

Section 4 describes how the sensitivity analysis was undertaken using the selected significant routes identified.

# 4. SENSITIVITY ANALYSIS RESULTS

This section presents the results of the sensitivity analysis carried out for the significant routes identified above. For each significant route, sensitive input variables are identified and the impact on monetised risk, generated by the assessed uncertainty for each specific variable, calculated in relation to other input variables within the same significant route.

We have chosen to sensitivity test each significant route independently. i.e. Carbon is tested independently of Safety. This because the monetised risk values vary significantly between each significant route; testing them together would potentially means that some variables that are sensitive for (e.g.) Availability risk, are not flagged as such as they are swamped by (e.g.) Environmental risk. Within our RIIO-T2 modelling we intend to set risk targets for independent service risk measures (e.g. maintain stable Safety risk), therefore it is essential that input data used to calculate the monetised risk for each independent service risk measure is tested for sensitivity.

## 4.1. METHOD & TOOLS ADOPTED

The sensitivity testing of model inputs will take place in two related phases:

1. Undertaking a spreadsheet-based sensitivity analysis on model inputs, made up of variables, coefficients and their associated calculations, using the relationships between individual asset failures to consequences and their associated risk

valuations (these relationships are described in the form of a risk map, or event tree[10])

2. Testing the impact of sensitive model parameters (determined above) on investment outcomes, measured as the optimised Asset Health (AH) plan under a “Stable Risk” planning scenario. This Stable Risk scenario has been discussed with stakeholders and is provisionally assumed to be their preferred scenario for RIIO-T2 AH investment planning.

Rather than use a commercial Monte Carlo tool, we have developed a bespoke Microsoft Excel model to undertake the uncertainty analysis; a model for Sites and a model for Pipelines. This tool has been used to produce the outputs in the following sections. A brief step-by-step summary of the developed approach is provided below:

### 4.1.1. Choose input variables to be modelled

The following characteristics were chosen to specifically exclude certain input data from the sensitivity analysis which might obscure the sensitivity of input data which has real uncertainty in terms of monetised risk outputs:

- Inputs are taken from a company data source for which there is no independent data source to validate against (referred to as Category A)
- Inputs that are industry default values which must be used, or no other reasonable values are available to be adopted with justification (referred to as Category B)
- Inputs that are calculated from other input data sources (referred to as Category C)

A few select Category B values were included where we have assessed that they may have a material impact on uncertainty and would highlight where improvements to these industry values may be necessary as part of future model improvement work. These are highlighted in the relevant sections below.

### 4.1.2. Apply uncertainties to input data parameters

These input parameters used and the applied maximum and minimum values are listed in Appendices D and E. Initially maximum values were assumed to be double the expected value (the value currently used in our Methodology and risk trading models) and minimum values one-half of the expected value. Where these ranges were perceived to be too great, for example being shown to be highly sensitive where we have reasonable confidence in the expected value, these uncertainty bands were tightened.

### 4.1.3. Replicate all monetised risk calculations

The monetised risk calculation process was replicated in MS Excel for all significant routes through the risk trading model (Carbon Emissions, Health and Safety and Availability). This allows:

- The calculation process to be followed and understood outside of our monetised risk and optimisation solution (AIM)

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[10] Main Methodology, Section 2.1

- VBA routines to be developed to model the impact of changing input variables on output calculations, the monetised risk for each Significant route through the risk map

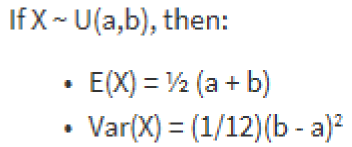
### 4.1.4. Sample the input data set

A specified number of sample points was selected and the sensitivity model then randomly selects an asset (or asset-failure mode combination) from the full model data set. The sample sizes were selected by trial and error, minimising the number of sample points whilst ensuring repeatability between results. The following sample sizes were used for the results presented below:

- Pipelines – 20,000 12-metre pipe section combinations
- Sites – 20,000 asset-failure mode combinations

### 4.1.5. Calculate the maximum, minimum and variance values for each asset

We assuming a rectangular distribution for variance and the values are calculated for repeat for each asset in the sampled data set.



If $X \sim U(a,b)$, then:

- $E(X) = ½ (a + b)$
- $Var(X) = (1/12)(b - a)^2$

Where **E(X)** is the expected value of the input variable; **a** and **b** are the upper and lower applied limits, respectively.

Therefore, upon completion of the sensitivity analysis, there are will be 20,000 individual variance values for each Pipeline 12-metre section and 20,000 variance values for each Site asset-failure mode combination.

### 4.1.6. Repeat for each individual input variable

Repeat the step above for each input variable in the sample individually, whilst keeping all other input variables fixed. Therefore, the arising variance for each asset/input variable combination is unique.

### 4.1.7. Find sample maximum, minimum and variance values

Average the maximum, minimum and variance values for the whole sample. This is statistically justifiable as each maximum, minimum and variance value has been independently calculated, assuming no correlation between individual asset values.

The maximum and minimum values show the average expected value of each asset within the sample based should a chosen input variable be allowed to vary between its assigned maximum and minimum values, with all other input variables fixed at the expected value.

Using the rectangular distribution, any value within the maximum and minimum range is equally likely to apply. We use this to calculate the variance for a **single** asset. We do this for **all** assets and then average them to estimate the value for the whole asset base.

The above approach allows the sensitivity of a single input variable, fixed at its assigned maximum and minimum value, to be tested independently of all other input variables within the significant route.

### 4.1.8. Calculate Equivalent Variance for each input variable

The sensitivity of each input variable was calculated using the Equivalent Variance (EV) value, where EV is defined as the ratio of the average variance of a specific input variable (for the sample population) divided by the maximum average variance for an input variable in the significant stream. Using Figure 10 below, <Vent Quantity> has an EV of 1 as it has the maximum variance for the chosen significant stream. <Minor Hole Size> has an EV of 0.18 based on dividing the average variance for <Minor Hole Size> (£0.17) by the average variance for <Vent Quantity> (£0.90).

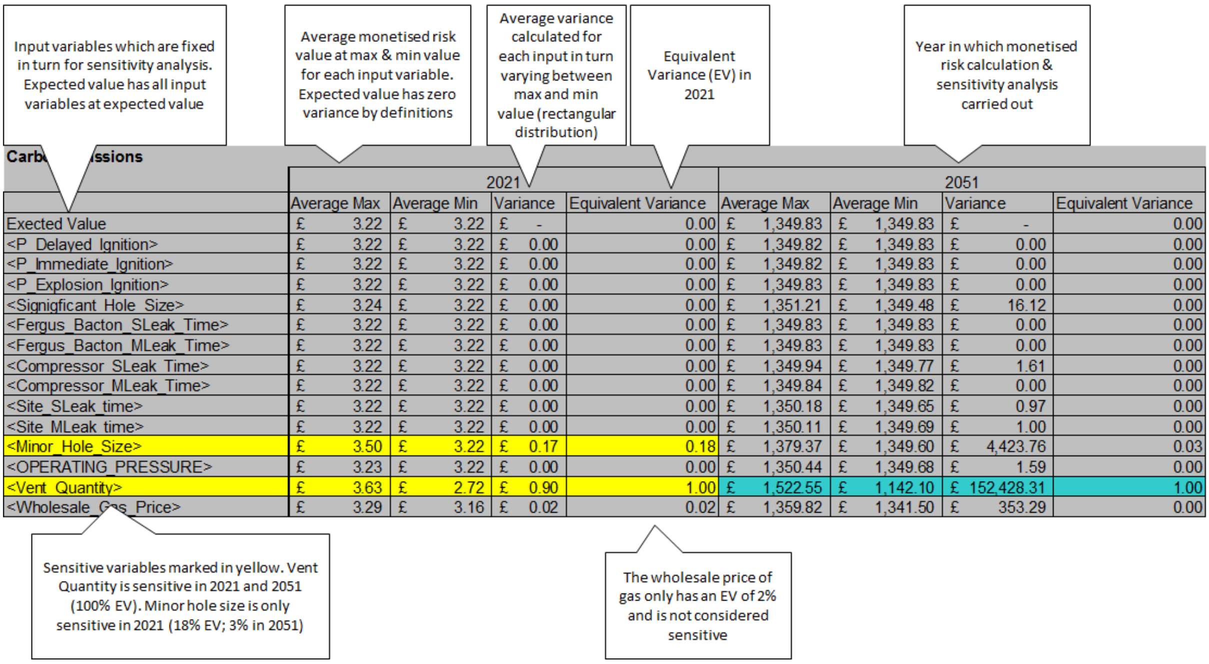
A sensitive input is defined as one which has an EV of 5% or more (i.e. the average variance is >5% of the maximum average variance of all input variables applied within the significant route sensitivity analysis).

This approach identifies sensitive variables within individual significant routes.

Sensitivity is carried out on monetised risk calculation in both 2021 and 2051 for the following reasons:

- 2021 monetised risk is most sensitive for T1 rebasing and T2 monetised risk reporting applications
- 2051 monetised risk is most sensitive for T2 investment planning applications

Figure 10 shows an example of how the data is presented for the Sites Carbon Emissions sensitivity analysis.



Input variables which are fixed in turn for sensitivity analysis. Expected value has all input variables at expected value

Average monetised risk value at max & min value for each input variable. Expected value has zero variance by definitions

Average variance calculated for each input in turn varying between max and min value (rectangular distribution)

Equivalent Variance (EV) in 2021

Year in which monetised risk calculation & sensitivity analysis carried out

**Carb ssions**

| | 2021 | | | | 2051 | | | |
|---|---|---|---|---|---|---|---|---|
| | Average Max | Average Min | Variance | Equivalent Variance | Average Max | Average Min | Variance | Equivalent Variance |
| Exected Value | £ 3.22 | £ 3.22 | £ - | 0.00 | £ 1,349.83 | £ 1,349.83 | £ - | 0.00 |
| <P_Delayed_Ignition> | £ 3.22 | £ 3.22 | £ 0.00 | 0.00 | £ 1,349.82 | £ 1,349.83 | £ 0.00 | 0.00 |
| <P_Immediate_Ignition> | £ 3.22 | £ 3.22 | £ 0.00 | 0.00 | £ 1,349.82 | £ 1,349.83 | £ 0.00 | 0.00 |
| <P_Explosion_Ignition> | £ 3.22 | £ 3.22 | £ 0.00 | 0.00 | £ 1,349.83 | £ 1,349.83 | £ 0.00 | 0.00 |
| <Signigficant_Hole_Size> | £ 3.24 | £ 3.22 | £ 0.00 | 0.00 | £ 1,351.21 | £ 1,349.48 | £ 16.12 | 0.00 |
| <Fergus_Bacton_SLeak_Time> | £ 3.22 | £ 3.22 | £ 0.00 | 0.00 | £ 1,349.83 | £ 1,349.83 | £ 0.00 | 0.00 |
| <Fergus_Bacton_MLeak_Time> | £ 3.22 | £ 3.22 | £ 0.00 | 0.00 | £ 1,349.83 | £ 1,349.83 | £ 0.00 | 0.00 |
| <Compressor_SLeak_Time> | £ 3.22 | £ 3.22 | £ 0.00 | 0.00 | £ 1,349.94 | £ 1,349.77 | £ 1.61 | 0.00 |
| <Compressor_MLeak_Time> | £ 3.22 | £ 3.22 | £ 0.00 | 0.00 | £ 1,349.84 | £ 1,349.82 | £ 0.00 | 0.00 |
| <Site_SLeak_time> | £ 3.22 | £ 3.22 | £ 0.00 | 0.00 | £ 1,350.18 | £ 1,349.65 | £ 0.97 | 0.00 |
| <Site_MLeak_time> | £ 3.22 | £ 3.22 | £ 0.00 | 0.00 | £ 1,350.11 | £ 1,349.69 | £ 1.00 | 0.00 |
| <Minor_Hole_Size> | £ 3.50 | £ 3.22 | £ 0.17 | 0.18 | £ 1,379.37 | £ 1,349.60 | £ 4,423.76 | 0.03 |
| <OPERATING_PRESSURE> | £ 3.23 | £ 3.22 | £ 0.00 | 0.00 | £ 1,350.44 | £ 1,349.68 | £ 1.59 | 0.00 |
| <Vent_Quantity> | £ 3.63 | £ 2.72 | £ 0.90 | 1.00 | £ 1,522.55 | £ 1,142.10 | £ 152,428.31 | 1.00 |
| <Wholesale_Gas_Price> | £ 3.29 | £ 3.16 | £ 0.02 | 0.02 | £ 1,359.82 | £ 1,341.50 | £ 353.29 | 0.00 |

Sensitive variables marked in yellow. Vent Quantity is sensitive in 2021 and 2051 (100% EV). Minor hole size is only sensitive in 2021 (18% EV; 3% in 2051)

The wholesale price of gas only has an EV of 2% and is not considered sensitive

Figure 10 - Sites model Carbon variances in 2021 and 2051

Figure 11 shows how monetised risk variance and equivalent variances can compared graphically for a single significant route.

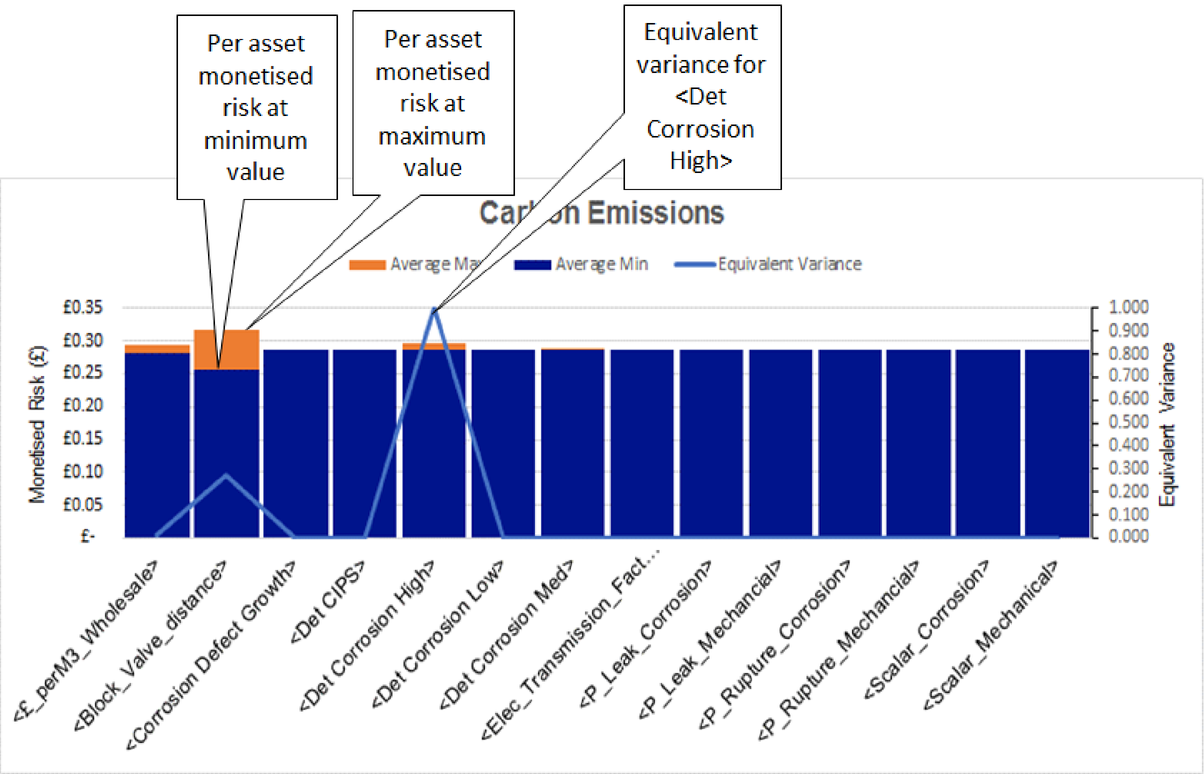


Figure 11 - Pipelines model Carbon sensitivity analysis in 2021

So, for the Carbon Emissions route through the Sites risk map the only sensitive input variables are:

- Vent quantity following a compressor trip and restart – Emergency Shut Down (ESD) vent
- Assumed leak hole size for a minor leak

## 4.2. PIPELINES SENSITIVITY TESTING

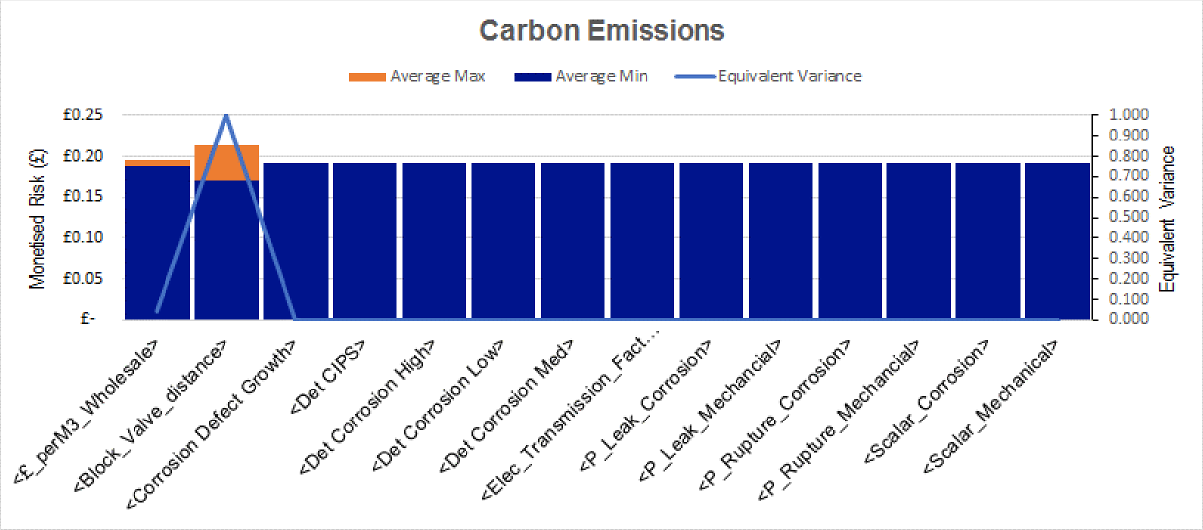
The following sections describe which input variables will be considered as sensitive within the Pipelines model and will be carried forward for detailed testing and/or validation. Alternative sensitivity tests were carried out

- By significant route through the risk trading models risk map
- For the start (2021) and end (2051) of the planning period to explore sensitivity for monetised risk reporting and investment planning respectively

### 4.2.1. Carbon Emissions (2021)

Based on the sensitivity modelling outputs presented below, the following input variables are deemed sensitive for Carbon Emissions in 2021.

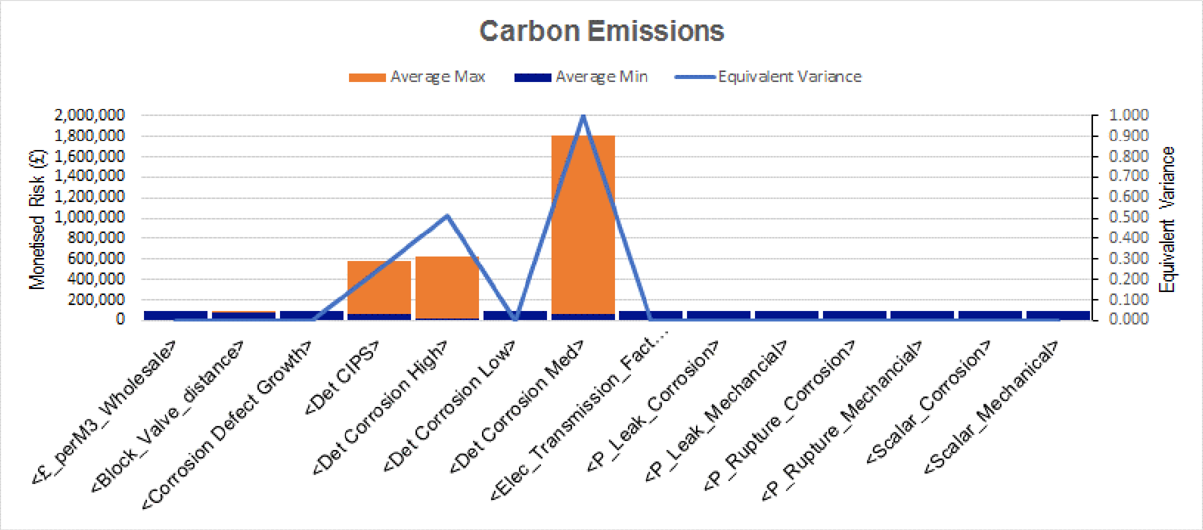
| Variable | Description | Equivalent Variance |
|---|---|---|
| <Block Valve Distance> | Assumed distance between block valves & assumed losses before depressurisation | 1.000 |



## 4.2.2. Carbon Emissions (2051)

Based on the sensitivity modelling outputs presented below, the following input variables are deemed sensitive for Carbon Emissions in 2051.

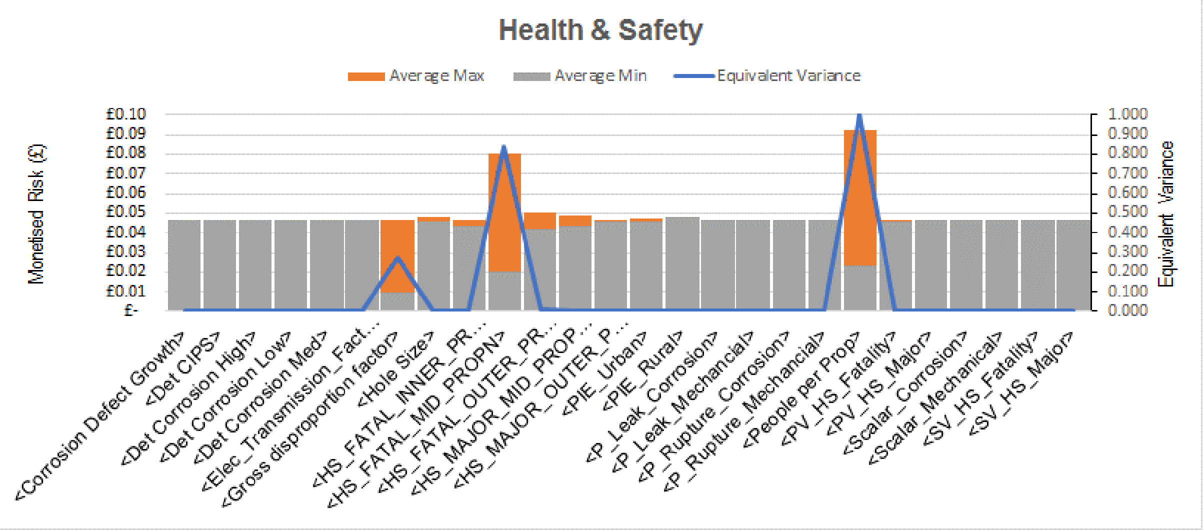
| Variable | Description | Equivalent Variance |
|---|---|---|
| <Det Corrosion Med> | Rate of corrosion growth with average CP protection (mm/year) | 1.000 |
| <Det Corrosion High> | Rate of corrosion growth with poor CP protection (mm/year) | 0.514 |
| <Det CIPS> | CP protection deterioration rate (mV/year). Rate of movement between High, Medium & Low protection bands | 0.252 |



### 4.2.3. Health & Safety (2021)

Based on the sensitivity modelling outputs presented below, the following input variables are deemed sensitive for Health and Safety in 2021.

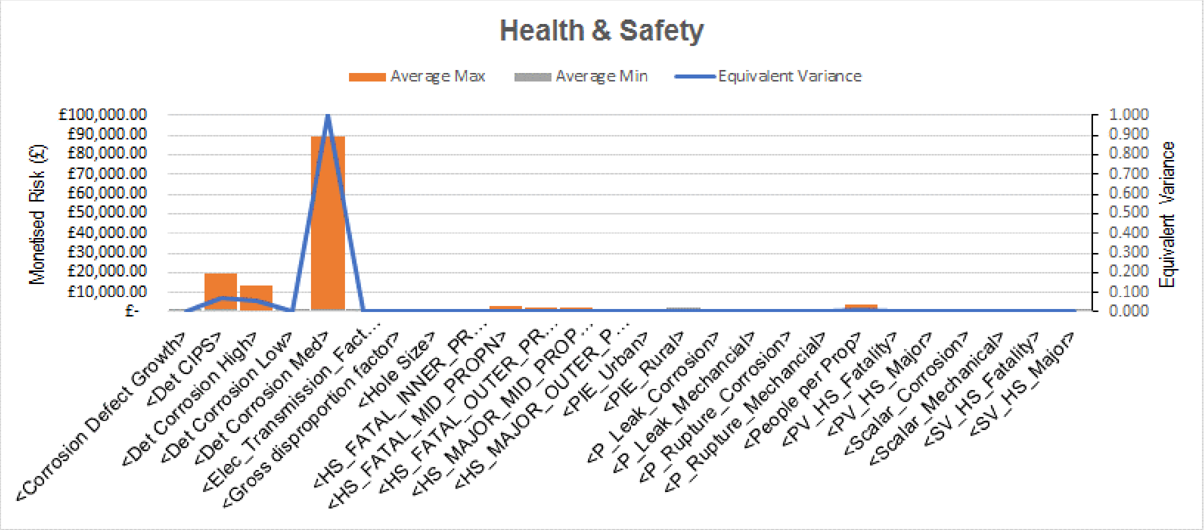
| Variable | Description | Equivalent Variance |
|---|---|---|
| <People per Property> | Assumed property occupancy | 1.000 |
| <HS_FATAL_MID_PROPN> | Probability of fatality in middle hazard zone | 0.833 |
| <Gross Disproportion Factor> | Factor applied to account for wider societal impacts of fatality / major injury | 0.277 |



### 4.2.4. Health & Safety (2051)

Based on the sensitivity modelling outputs presented below, the following input variables are deemed sensitive for Health and Safety in 2051.

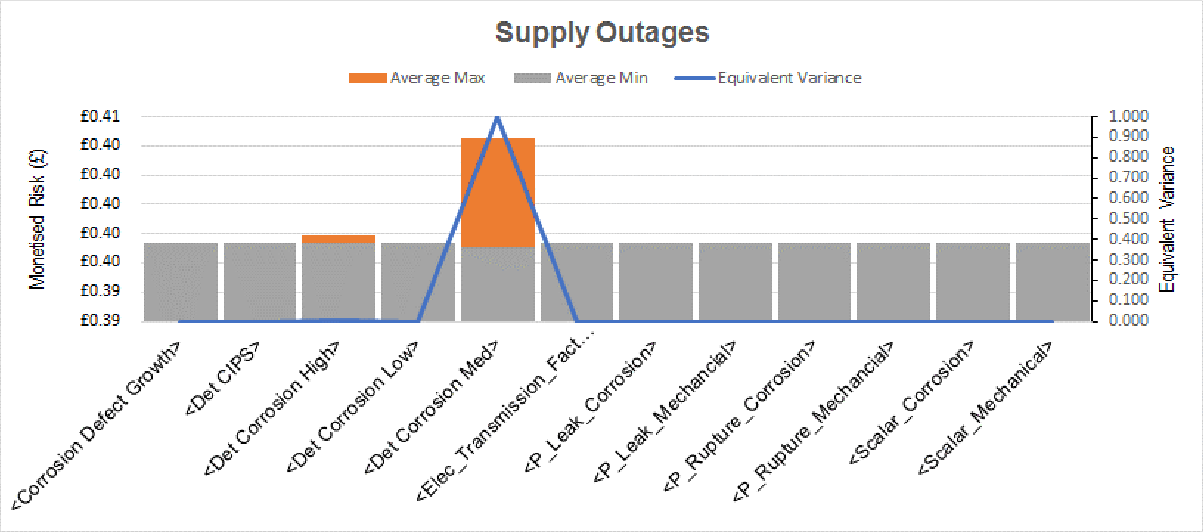
| Variable | Description | Equivalent Variance |
|---|---|---|
| <Det Corrosion Med> | Rate of corrosion growth with average CP protection (mm/year) | 1.000 |
| <Det CIPS> | CP protection deterioration rate (mV/year). Rate of movement between High, Medium & Low protection bands | 0.072 |
| <Det Corrosion High> | Rate of corrosion growth with poor CP protection (mm/year) | 0.056 |



## 4.2.5. Availability & Reliability (2021)

Based on the sensitivity modelling outputs presented below, the following input variables are deemed sensitive for Availability and Reliability in 2021.

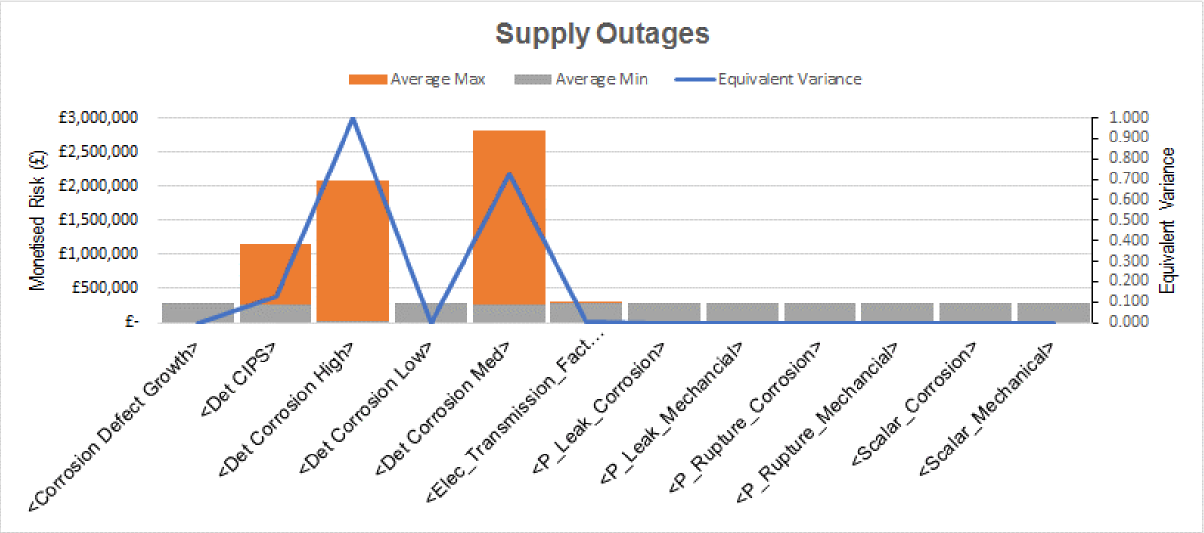
| Variable | Description | Equivalent Variance |
|---|---|---|
| <Det Corrosion Med> | Rate of corrosion growth with average CP protection (mm/year) | 1.000 |
| <Det Corrosion High> | Rate of corrosion growth with poor CP protection (mm/year) | 0.004 |



## 4.2.6. Availability & Reliability (2051)

Based on the sensitivity modelling outputs presented below, the following input variables are deemed sensitive for Availability and Reliability in 2051.

| Variable | Description | Equivalent Variance |
|---|---|---|
| <Det Corrosion High> | Rate of corrosion growth with poor CP protection (mm/year) | 1.000 |
| <Det Corrosion Med> | Rate of corrosion growth with average CP protection (mm/year) | 0.727 |
| <Det CIPS> | CP protection deterioration rate (MeV/year). Rate of movement between High, Medium & Low protection bands below | 0.127 |



## 4.3. SITES SENSITIVITY TESTING

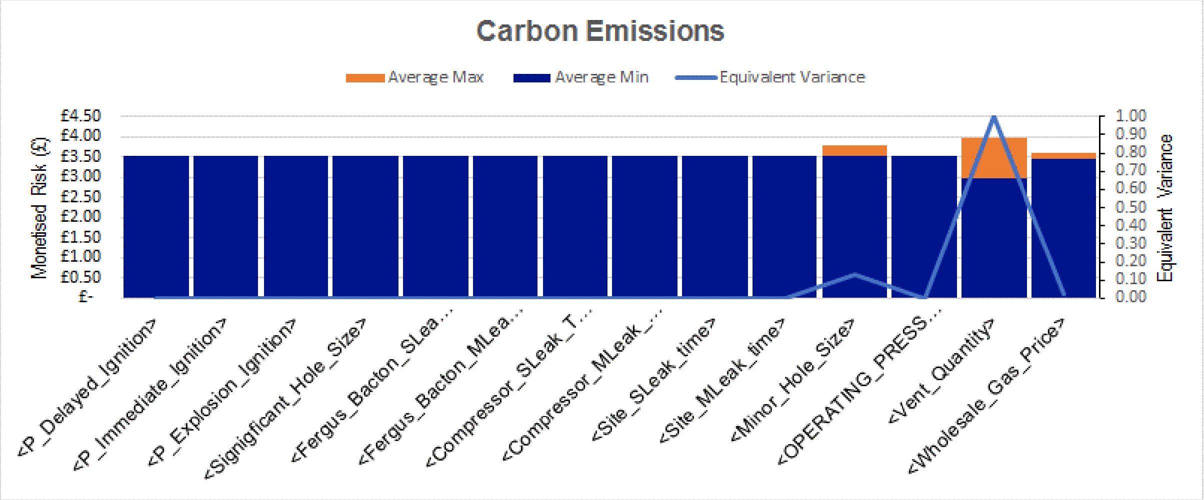
The following sections describe which input variables will be considered as sensitive within the Pipelines model and will be carried forward for detailed testing and/or validation. Alternative sensitivity tests were carried out

- By Significant route through the risk trading models risk map
- For the start (2021) and end (2051) of the planning period to explore sensitivity on T1 and T2 monetised risk reporting and T2 investment planning respectively

### 4.3.1. Carbon Emissions (2021)

Based on the sensitivity modelling outputs presented below, the following input variables are deemed sensitive for Carbon Emissions in 2021.

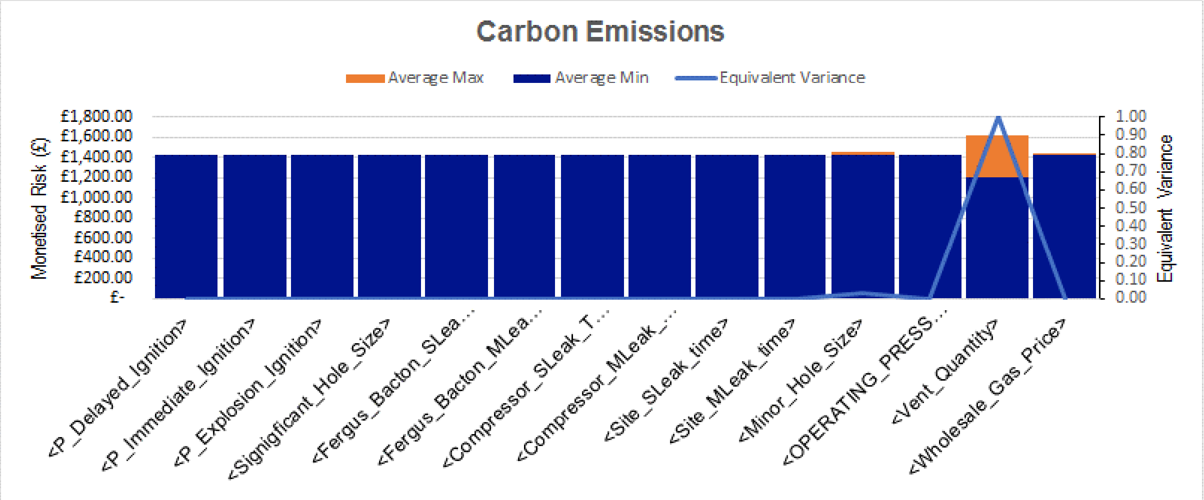
| Variable | Description | Equivalent Variance |
|---|---|---|
| <Vent Quantity> | Volume of a compressor vent (ESD) | 1.00 |
| <Minor Hole Size> | Assumed hole size for a minor leak (mm) | 0.13 |



## 4.3.2. Carbon Emissions (2051)

Based on the sensitivity modelling outputs presented below, the following input variables are deemed sensitive for Carbon Emissions in 2051.

| Variable | Description | Equivalent Variance |
|---|---|---|
| <Vent Quantity> | Volume of a compressor vent (ESD) | 1.00 |
| <Minor Hole Size> | Assumed hole size for a minor leak (mm) | 0.03 |

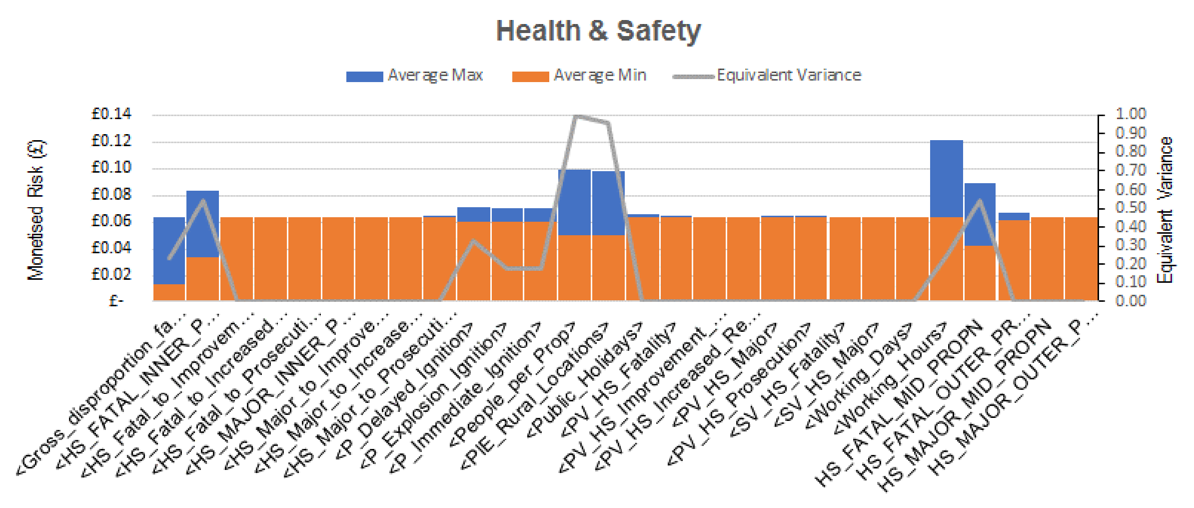


## 4.3.3. Health & Safety (2021)

Based on the sensitivity modelling outputs presented below, the following input variables are deemed sensitive for Health and Safety in 2021.

| Variable | Description | Equivalent Variance |
|---|---|---|
| <People per Prop> | Average property occupancy | 1.00 |

| | | |
|---|---|---|
| <Rural Locations> | Factor applied to reduce probability of death/injury in urban area | 0.96 |
| <HS_FATAL_MID_PROPN> | Number of properties in | 0.55 |
| <HS_FATAL_INNER_PROPN> | Probability of fatality in inner hazard zone | 0.54 |
| <P_Delayed_Ignition> | Probability of a delayed ignition following leak | 0.33 |
| <Gross disproportion factor> | Factor applied to account for wider societal impacts of fatality / major injury | 0.24 |
| <Working Hours> | Working hours (exposed to asset) for employees | 0.24 |
| <P_Explosion_Ignition> | Probability of an explosion following an ignition | 0.18 |
| <P_Immediate_Ignition> | Probability of an immediate ignition following a leak | 0.18 |

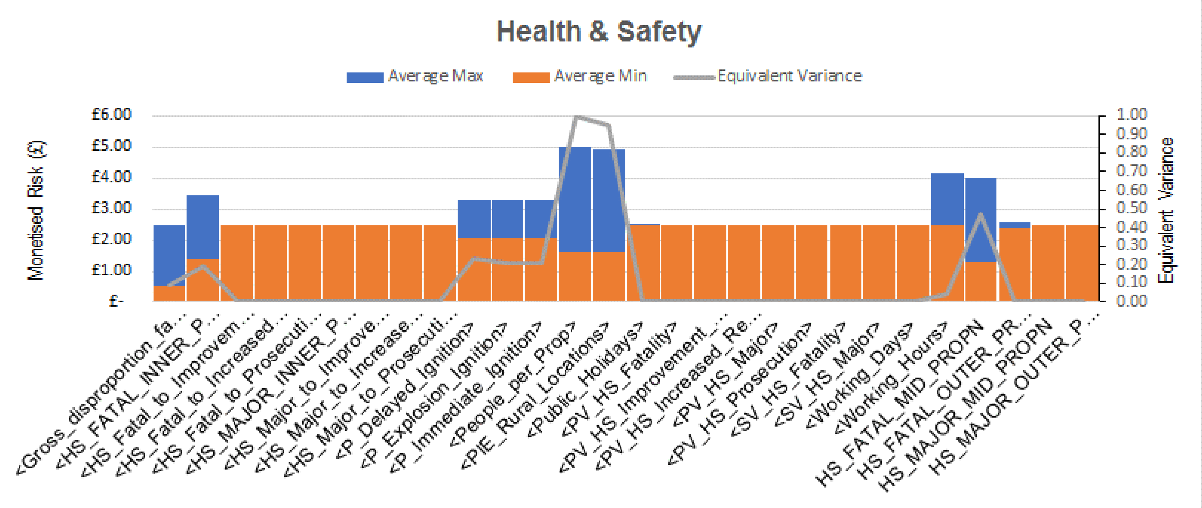


### 4.3.4. Health & Safety (2051)

Based on the sensitivity modelling outputs presented below, the following input variables are deemed sensitive for Health and Safety in 2051.

| Variable | Description | Equivalent Variance |
|---|---|---|
| <People per Prop> | Average property occupancy | 1.00 |
| < Rural Locations> | Factor applied to reduce probability of death/injury in urban area | 0.95 |
| <HS_FATAL_MID_PROPN> | Number of properties in | 0.47 |

| | | |
|---|---|---|
| <P_Delayed_Ignition> | Probability of a delayed ignition following leak | 0.23 |
| <P_Explosion_Ignition> | Probability of an explosion following an ignition | 0.21 |
| <P_Immediate_Ignition> | Probability of an immediate ignition following a leak | 0.21 |
| <HS_FATAL_INNER_PROPN> | Probability of fatality in inner hazard zone | 0.19 |
| <Gross disproportion factor> | Factor applied to account for wider societal impacts of fatality / major injury | 0.09 |



## 4.3.5. Availability & Reliability (2021 and 2051)

Availability and reliability risk is modelled simplistically within the Sites risk trading model. All monetised risk calculations are carried out in an off-line spreadsheet; each NTS site (or compressor unit) is assigned an individual monetised risk value based on several input parameters. This is discussed further in Section 9.

The modelling approach for estimating Availability and Reliability monetised risk is summarised below:

- The number of defects for each asset is calculated
- If the defect may potentially cause a site or unit outage, then the probability of this consequence is applied[11]
- The resulting number of outages is the number of potential site or unit outages that may arise following asset failure. It is important to note here that most failures that could cause an outage do not actually generate an outage. This is because the

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[11] Probability of Failure Supporting document, Section 5.2 and 5.3

failure is mitigated through a combination of system resilience and operational intervention (e.g. reconfigure the network; use commercial mechanisms to reduce demand for gas). These operational interventions are not considered within our risk modelling.

- This number of potential outages is then calibrated to an actual number of outages by applying a factor (<AV_Scalar>). The base expected frequency of outages is an assumption discussed with the System Operator and agreed to be reasonable.
- The consequence value is calculated for each asset or pipe section using the method described in the Consequence of Failure[12] and Service Risk Framework[13] supporting documents.
- The rationale behind the applied supply and demand scenario, which influences the magnitude and distribution of monetised risk across the NTS, is discussed in Section 9

This calibration factor (<Av_Scalar>) is the only sensitive input variable for Sites Availability and Reliability as all other input values are either Category A or B. (see Section 4.1.1). Variances for <Av_Scalar> in 2021 and 2051 are presented below for completeness.

The impact of changing this calibration factor on monetised risk, and investment to manage risk, is discussed in Section 5.2.4 and Section 5.3.1.

## 4.4. SUMMARY OF SENSITIVITY ANALYSIS OUTCOMES

Based on the analysis presented above, the following input variables will be taken forward for further justification (Section 7). Table 10 displays the sensitive input data for Sites. Table 11 shows the sensitive input data for Pipelines.

The sensitive years' column describes whether the input variable is sensitive in 2021, 2051 or both. In simple terms, sensitivity in 2021 implies the variable is sensitive for short-term monetised risk reporting and rebasing. Sensitivity in 2051 implies that the variable is potentially sensitive for investment planning, as the benefits delivered through investment accrue over the planning period.

A high-level description of why that variable is sensitive in the context of the overall Methodology is provided.

Table 10 - Sensitive input variables for Sites

| Variable | Description | Driver | Sensitive Years | Reason for sensitivity |
|---|---|---|---|---|
| <Vent Quantity> | Volume of a compressor vent (ESD) | Carbon | 2021<br>2051 | Compressor vents are relatively frequent and the volume of gas vented is significant |

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[12] Section 6

[13] Section 6 and Appendix E

| Variable | Description | Driver | Sensitive Years | Reason for sensitivity |
|---|---|---|---|---|
| <Minor Hole Size> | Assumed hole size for a minor leak (mm) | Carbon | 2021 | There are more minor than major leaks and fixed orifice size assumptions controls the volume of gas lost over a fixed time and gas pressure |
| <People per Prop> | Average property occupancy | Safety | 2021<br>2051 | More people assumed to be in the property the greater the fatality/injury rate and higher the social fatality risk |
| <HS_FATAL_MID_PROPN> | Number of properties in the MIDDLE hazard zone (4 x BPD) | Safety | 2021<br>2051 | More people assumed to be killed/injured the higher the social fatality risk. |
| <Rural Locations> | Factor applied to reduce probability of death/injury in urban area | Safety | 2021<br>2051 | This is a correction factor agreed through the expert review to consider that not all properties within hazard zones are equally at risk |
| <P_Delayed_Ignition> | Probability of a delayed ignition following leak | Safety | 2021<br>2051 | Directly factors the number of predicted fires or explosions. Only applies to significant leaks |
| <P_Explosion_Ignition> | Probability of an explosion following an ignition | Safety | 2021<br>2051 | Directly factors the number of predicted explosions |
| <P_Immediate_Ignition> | Probability of an immediate ignition following a leak (due to likely failure of fire protection system) | Safety | 2021<br>2051 | Directly factors the number of predicted fires or explosions (on sites with a fire protection system in place) |
| <HS_FATAL_INNER_PROPN> | Probability of fatality in inner hazard zone | Safety | 2021<br>2051 | More people assumed to be killed/injured the |

| Variable | Description | Driver | Sensitive Years | Reason for sensitivity |
|---|---|---|---|---|
| | | | | higher the social fatality risk. |
| <Gross disproportion factor> | Factor applied to account for wider societal impacts of fatality / major injury | Safety | 2021<br>2051 | Multiplies the HSE value of a fatality directly, so more fatalities/injuries the higher the social fatality risk |
| <Working Hours> | Working hours (exposed to asset) for employees | Safety | 2021 | The more working hours, the higher the risk that an employee is on site at the time of a fire/explosion and a higher chance of death or injury |

Table 11 - Sensitive input variables for Pipelines

| Variable | Description | Driver | Sensitive Years | Reasons for sensitivity |
|---|---|---|---|---|
| <Det Corrosion High> | Rate of corrosion growth with bad CP protection (mm/year) | Carbon<br>Safety<br>Availability | 2021<br>2051 | Rate of corrosion hole growth increases resulting in more corrosion leaks |
| <Det Corrosion Med> | Rate of corrosion growth with average CP protection (mm/year) | Carbon<br>Safe<br>Availability | 2021<br>2051 | Rate of corrosion hole growth increases resulting in more corrosion leaks. |
| <Block Valve Distance> | Assumed distance between block valves & assumed losses before depressurisation | Carbon | 2051 | Volume of gas required to be vented to carry out leak and rupture repairs. Increases with numbers of predicted leaks and ruptures. Impact is predominantly due to leaks. Distance between block valves can be 10’s of kilometres, therefore volumes of gas vented are significant |
| <Elec_Transmission_Factor> | Increased corrosion growth & deterioration due to AC interference (presence of HV cable within 50m) | Carbon | 2051 | Rate of corrosion hole growth increases resulting in more corrosion leaks. Only applies to c. 1.7% of pipeline network but |

| Variable | Description | Driver | Sensitive Years | Reasons for sensitivity |
|---|---|---|---|---|
| | | | | becomes important by 2051 without intervention |
| <Det CIPS> | CP protection deterioration rate (mV/year). Rate of movement between High, Medium & Low protection bands below | Carbon<br>Safety<br>Availability | 2051 | Rate of corrosion hole growth increases resulting in more corrosion leaks |
| <People per Property> | Assumed property occupancy (average over a 24-hour day assuming a failure can occur at any time) | Safety | 2021<br>2051 | More people assumed to be in the property the greater the fatality/injury rate and higher the social fatality risk |
| <HS_FATAL_MID_PROPN> | Probability of fatality in middle hazard zone | Safety | 2021<br>2051 | More people assumed to be killed/injured the higher the social fatality risk. |
| <Gross Disproportion Factor> | Factor applied to account for wider societal impacts of fatality / major injury | Safety | 2021 | Multiplies the HSE value of a fatality directly, so more fatalities/injuries the higher the social fatality risk |

# 5. MATERIALITY OF INPUT DATA UNCERTAINTY ON OUTCOMES

## 5.1. APPROACH

The sensitivity testing carried out on individual input variables above has identified which contribute most significantly towards monetised risk calculations within individual significant streams/routes through the risk map. This is an alternative sensitivity test that explores how applying extreme value tests influences the outputs from our risk trading models (AIM). This complements the sensitivity analysis in Section 4 and demonstrates the sensitivity across all streams/routes through the risk map.

Our investment optimisation tool works to output the best possible selection of assets and investments (interventions) to achieve a defined target scenario. These scenarios can be based on:

- Cost
- Risk
- Service levels / outcomes
- Any combination of the above

An example output from AIM is shown in Figure 12 which profiles the cumulative Whole Life Net Benefit (WLNB) delivered by alternative investment scenarios over the planning period.

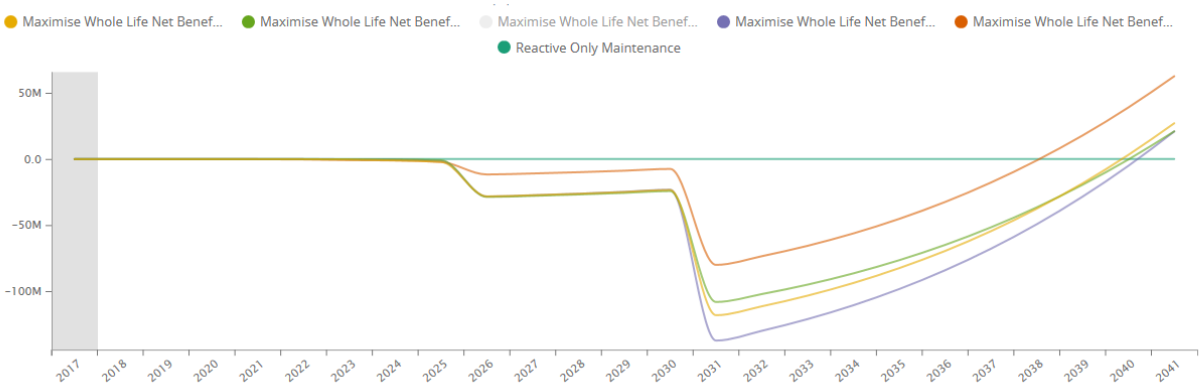

**Figure 12 – Whole Life New Benefit for alternative investment scenarios. The point at which the lines cross the zero WLNB value can be considered the payback period (where plans become cost beneficial)**

The RIIO-T2 asset health investment plan will consider which scenarios are taken forward into our Business Plan, based on discussions and agreement with stakeholders. For the purposes of model validation, we have chosen to use a Stable Service Risk scenario, which is closest in line with our currently perceived stakeholders' service expectations. The modelling constraints applied for the stable service risk scenario are as follows:

- Numbers of fatalities and injuries held stable at current (2017) expected values until 2028, then allowed to deteriorate[14]
- Volumes of unburned gas emissions held stable at current expected values until 2028, then allowed to deteriorate
- Numbers of transport disruption events held stable at current expected values, then allowed to deteriorate
- Frequency of supply outages held stable (the number of model predicted outages are the same under all scenarios)
- For scenarios relating to Availability/Reliability risk a 1 year in 20-year demand (FES Steady Progression, 2021 Demand) monetised risk value has been used (see Section 9)
- For other scenarios, a high winter's day demand monetised risk value has been used

The model will then find the blend of asset interventions that delivers the maximum WLNB to achieve the above constraint targets.

For each input parameter, a simplified "double" or "halve" the expected value has been used. The purpose of these tests is to explore the relative, not the absolute, impact of changing input conditions on modelled TMR and investment outputs.

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[14] This is to ensure that costs and benefits accrued beyond RIIO-T2 do not influence the comparisons

The scenarios chosen were based on the sensitivity testing carried out in Sections 4.2 and 4.3, or to illustrate specific points of interest such as defects rates.

The outputs show how input data uncertainty changes the TMR or cumulative investment costs in 2051, relative to a base position where the expected values of all model inputs are used (x1).

## 5.2. SITES OUTCOME TESTING

To test the sensitivity of the Sites model changes were made to the risk trading model to test their impact on:

1. The total monetised risk under a Without Intervention (or reactive maintenance only scenario)
2. The investment levels (proactive investment costs) under a stable service risk scenario (maintain current level of service risk in 2028).

Using the “double” and “halve” approach described previously, the relative differences in the above values were compared. For clarity, 1. above relates to the reduction in NTS risk delivered while 2. relates to the cost of achieving stable service risk by 2028.

### 5.2.1. Asset Defects Frequency

This materiality analysis was undertaken using a high winter’s day demand scenario.

The source of defects data is our Ellipse asset management system. Field operatives identify faults during routine inspection and maintenance and any works requiring rectification are recorded as defects, which are then planned and scheduled for rectification. Defect data is taken from Ellipse over several years, grouped into assets which have similar purposes and failure modes, and then averaged to give an annual defect frequency. We assume that this defect frequency is error-free through routine Ellipse QA and data management processes.

The defect (or failure) frequency node provides our initial PoF estimates for all assets and subsequently drives all modelled consequence frequencies and monetised risk valuations. Doubling and halving the defects frequency will therefore have a proportionate impact on monetised risk.

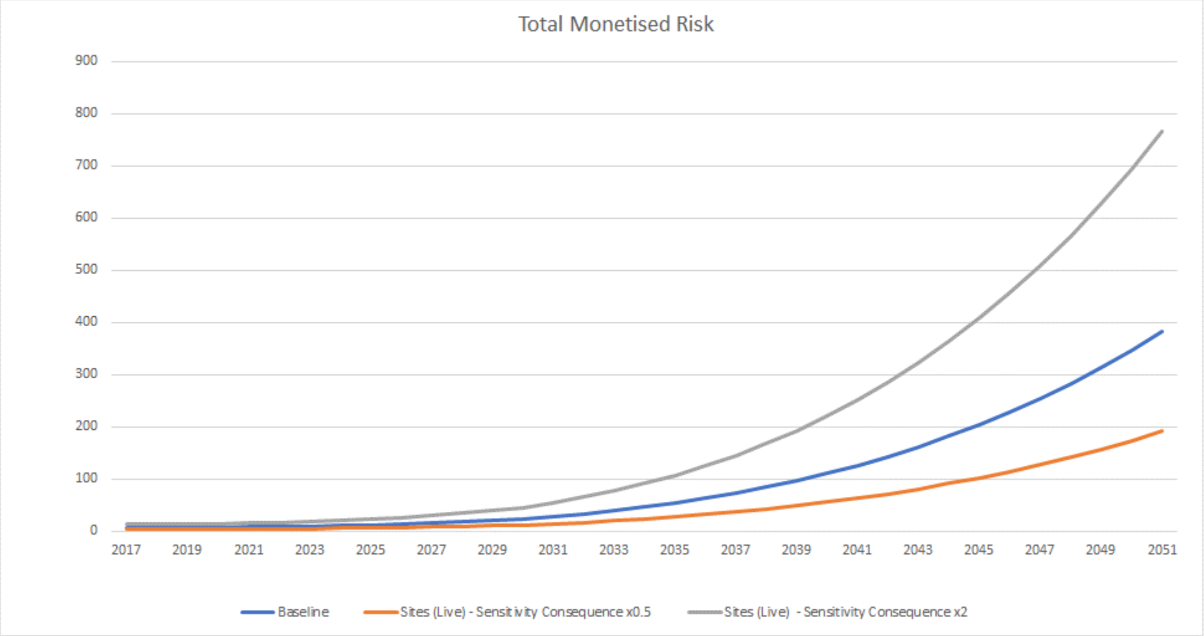

**Figure 13: Impact of changing initial defect numbers on monetised risk (units are relative monetised risk)**

Under a stable service risk scenario, the impact on proactive CAPEX spend is not significant. As explained previously, investment levels are sensitive to the rate of increase in risk (marginal change) rather than the absolute level of risk. This can be explained by:

1. The starting levels of risk are higher/lower, but deteriorate at the same rate
2. The benefit delivered through interventions will also be higher/lower in proportion to the start position

In summary, the number of defects is directly proportional to the level of monetised risk, although this will vary across asset groups (as some carry more risk than others).

### 5.2.2. Asset Defects Deterioration

This materiality analysis was undertaken using a high winter's day demand scenario.

We would expect levels of proactive investment under a stable service risk scenario to be sensitive to the assumed rate of asset defects deterioration (rate of change over time). Each asset type has its own assumed deterioration rate and for this extreme value test all rates have been either doubled or halved.

Table 12 shows the impact of changing the deterioration rate on proactive investment levels in 2028. Doubling or halving the deterioration rate roughly increases or decreases the level of required investment by 10%. This is explained by the investment optimiser needing to undertake more proactive work to manage risk levels when deterioration rates are higher, and vice versa. However, the impact on investment is not directly proportional (as for monetised risk) as the investment optimiser will try to choose the lowest cost / greatest benefit investments, wherever possible, to meet the stable service risk constraint. However, the profile of investments across different asset types is sensitive to the applied deterioration rates.

| **Scenario** | **% Difference in Proactive CAPEX - 2028** |
|---|---|
| Deterioration x 0.5 | -8.88% |
| Deterioration x 2.0 | 9.41% |

**Table 12 – Percentage difference in proactive CAPEX under different defect deterioration rates**

### 5.2.3. Numbers of Properties at Risk within Hazard Zones

This materiality analysis was undertaken using a high winter's day demand scenario.

The numbers of people in properties at risk of death or injury because of asset failure is highly sensitive input to the model. These are estimated using defined hazard zones and estimates of numbers of properties at risk within the spatial boundary defined by the zone. Decreasing consequence severities apply at increasing distances from the fire or explosion which may result from asset failure (and subsequent ignition of escaped gas).

The extreme-value impact of changes hazard zone areas and/or differences in assumed at-risk property counts were both tested by halving and doubling the number of properties within each hazard zone (Inner. Middle and Outer). These tests will impact proportionally on the numbers of people at risk of death, injury or lost time incidents (LTIs).

The number of predicted major injuries per annum is shown in Figure 14. As expected the numbers rise in proportion to the numbers of properties at risk.

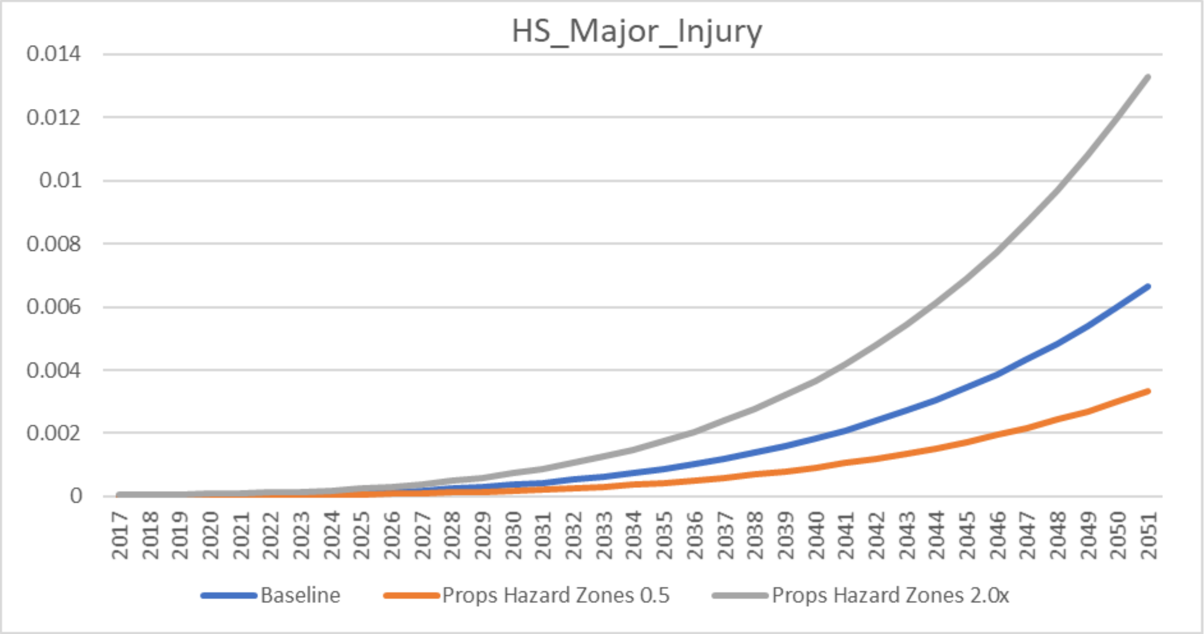

**Figure 14 – Predicted number of major injuries per annum**

Table 13 shows that the impact on TMR in 2051 is relatively small. This is because Safety risk for Sites, although important, is low and even with deterioration does not rise to a level where it contributes significantly to TMR, which is dominated by Financial and Environmental risk. Safety risk is low because deaths and injuries from fires are constrained to site boundaries, and explosions occurring at locations which could impact he public outside of the site boundary are rare.

| **Scenario** | **Percentage Difference 2051** |
|---|---|
| Properties x 0.5 | -0.79% |
| Properties x 2.0 | 0.52% |

Table 13 - Percentage difference in total monetised risk in 2051 compared to baseline (expected value) scenario

Likewise, changing the numbers of properties at risk does not significantly impact on future levels of investment as the relatively small value of Safety monetised risk does not generate significant levels of cost-beneficial investment beyond 2028.

In summary, neither TMR or investment levels are sensitive to changing the numbers of properties at risk within hazard zones. The same conclusion would hold true if we changed the following parameters:

- The size/area of the hazard zones
- The number of people in each property
- The assumption as to what proportion of people are killed or injured because of a fire or explosion

This is the case because all factors above have the same directly proportional impact on Safety risk as do the numbers of properties within each hazard zone.

### 5.2.4. Availability and Reliability Consequences

This materiality analysis was undertaken using a 1 year in 20-year demand scenario.

A calibration factor has been applied to convert the relatively high number of asset failures that could potentially cause a supply outage to an expected frequency of site outages in line with historic experience. We have very few actual outages as events are mitigated through NTS resilience or avoided by compensating customers to reduce demands. However, an estimate of this value is necessary such that some Availability risk is quantified within our risk models.

Table 14 shows the impact of doubling or halving the proportion of failure events (that could cause an outage) that will cause a supply outage. This is currently set to be 0.001 (1 in 1000). Changing this factor changes the probability of an unmitigated outage from 1 in 5 years to 1 in 10 and 1 in 2.5 years respectively (in 2017). In terms of total monetised risk, the difference between the baseline and these extreme scenarios in 2051 can be expressed as:

| **Scenario** | **Difference in Total Monetised Risk 2051** |
|---|---|
| AR x 0.5 | -0.99% |

| | |
|---|---|
| AR x 2 | 1.77% |

**Table 14: Percentage difference in total monetised risk in 2051 compared to baseline (expected value) scenario**

This relatively small change illustrates that for Sites, Availability and Reliability (AR) contributes a relatively small proportion of total monetised risk (TMR). Therefore, changing the assumption as to the proportion of failures that will generate a supply outage is insensitive to the overall level of NTS monetised risk.

Figure 15 below shows that the numbers of outages do increase greatly under a Without Investment scenario, requiring proactive investment to achieve a stable service risk outcome. It is important to state that although monetised risk sensitivity may be low, investment is still required to achieve expected service outcomes.

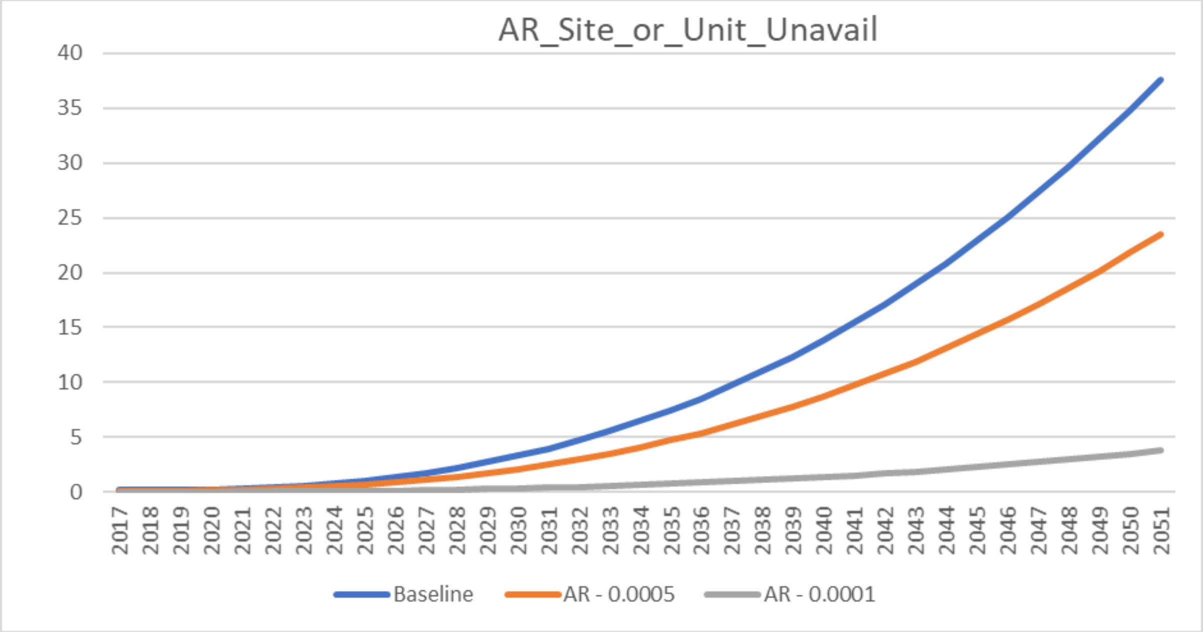

**Figure 15 - Predicted number of outages with no intervention (nr./year)**

Although the initial AR risk values have changed, the level of spend to achieve stable risk by 2028 is similar. This is because under the Stable Service Risk scenario only the marginal changes in risk value must be addressed through investment, while the baseline level of risk (be it higher or lower) remains constant.

Under a stable service risk scenario, the level of investment required is insensitive to the absolute level of risk. However, the level of investment will however be sensitive to different rates of change in risk (such as differences in deterioration assumptions).

### 5.2.5. Removing Availability and Reliability Risk from Pipework

This materiality analysis was undertaken using a 1 year in 20-year demand scenario.

The expert review report stated that block valve sites, which are primarily used to isolate areas of the network to undertake repairs or maintenance, contribute little to Availability and

Reliability risk (Section 6.2.1, Recommendation 8). This is because the magnitude of the failure may be unlikely to require a full site shut-down to resolve, or the NTS can be operated in alternative ways to prevent the outage. Removing block valves from the overall Loss of Supply (LOS) consequence assessment, which is carried out in an offline spreadsheet, is not straightforward. However, we have developed an alternative test which effectively "switches off" the LOS risk from all assets with a Primary Asset Class (PAC) of Pipeline, which predominantly relates to block valve sites.

Figure 16 shows that removing these block valve assets has an inconsequential effect on the numbers of predicted outages and therefore would have little impact on monetised risk or investment levels.

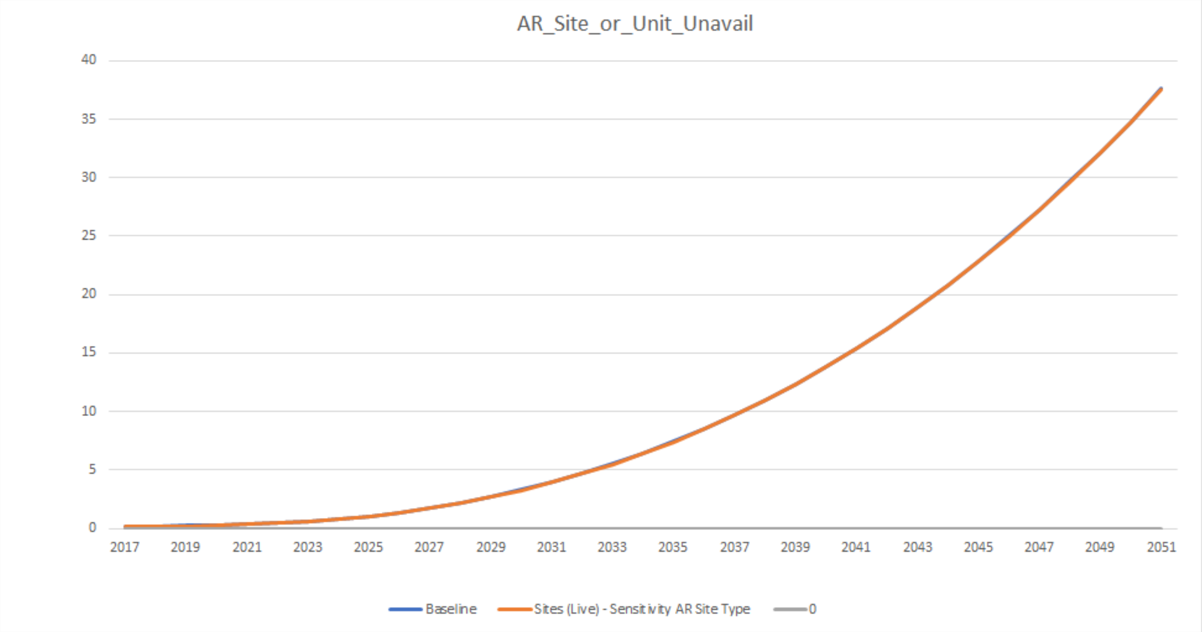

Figure 16: Predicted numbers of outages with and without block valve sites (nr./year)

### 5.2.6. Increasing Significant Leak Hole Size

This materiality analysis was undertaken using a high winter's day demand scenario.

Currently we assume a "significant" leak will have a diameter of 5mm. The expert review comments that the industry generally uses a bigger leak size to define what is significant. The rate of significant leaks is very low and we do not have any data to validate this assumption against, therefore it is important to test the sensitivity of the assumption on monetised risk and investment.

Changing the assumed hole diameter for a significant leak from 5mm to 10mm will increase the volume of gas emitted and generate greater Environment risk and will also impact on the probability of a fire or explosion occurring, leading to increases in Safety and Societal (transport disruption) risk. Figure 17 shows that an increase in the assumed Significant leak size from 5mm to 10mm causes around 0.002 additional fatalities per year by 2051 (13% increase). This is due to the higher risk of a fire or explosion at higher leak flow rates.

The modelling of the Safety and Environmental risk is complex. As the probability of a fire or explosion increases (ignition), the volume of unburned gas being emitted from a gas leak reduces. For a larger hole size, the volume of unburned gas emitted at a fixed pressure is greater. This generates an overall increase in the volume of gas emitted but the increase is not directly proportional (Figure 17).

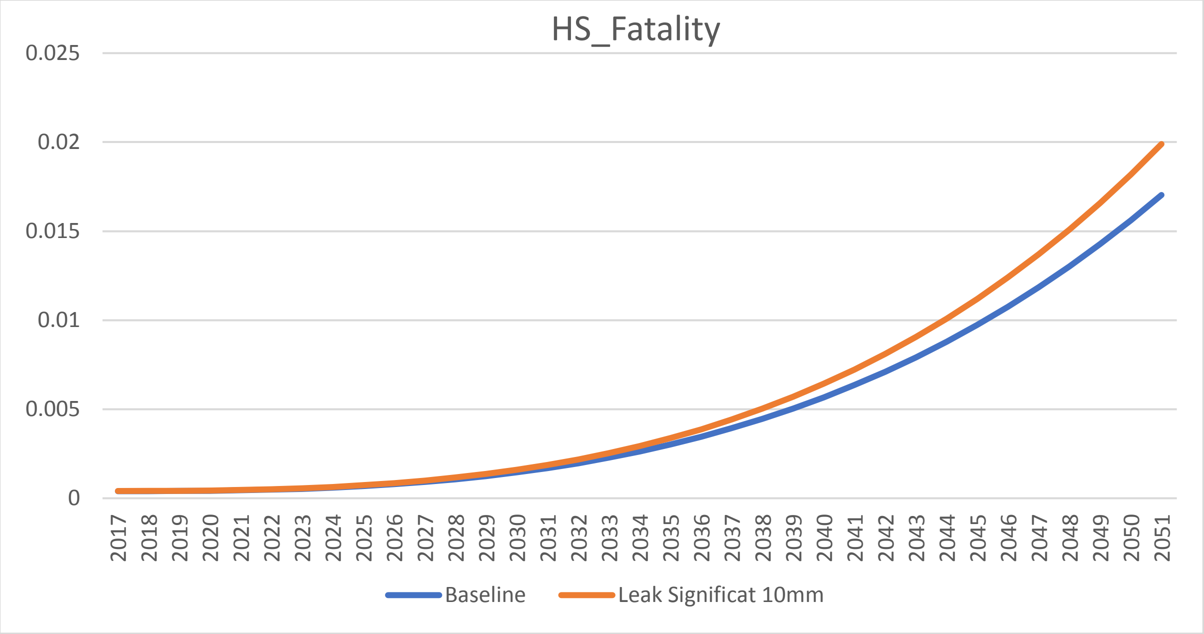

Figure 17: Impact of an increased significant leak hole size on predicted fatalities (nr./year)

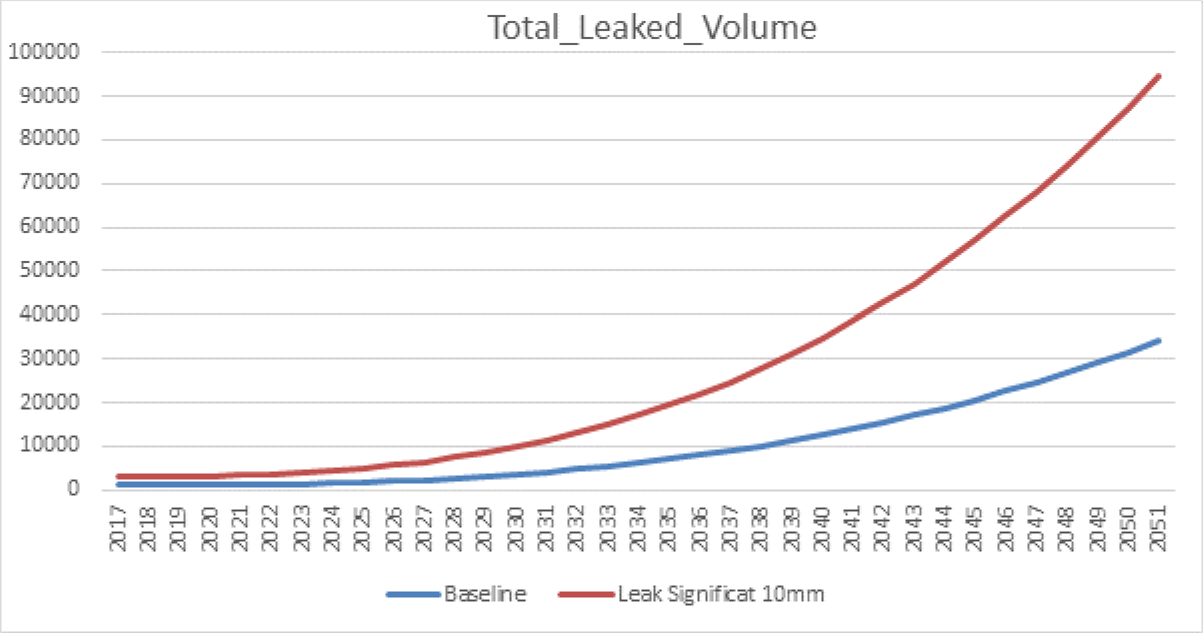

**Figure 18: Total gas emitted from significant leaks (m3/year)**

In terms of monetised risk, significant leaks are a small component of total leaked gas volume, which is dominated by maintenance activities and compressor ESD vents. As the Safety consequences arising from significant leaks are also low, there is only a small impact on monetised risk caused by doubling the leak hole size.

The impact of increasing the significant leak hole size has an interesting impact on proactive investment costs. Increasing the leak hole size decreases the level of cost-beneficial spend over the planning period.  This is because Safety risks arising from are concentrated on a relatively small number of assets, and while the service risk has increased so has as the risk benefits delivered by investment. This means that it is cost-beneficial to invest in fewer, higher risk, assets under the 10mm leak size scenario, therefore overall levels of proactive spend are lower.

### 5.2.7. Reducing Minor Leak Hole Size

This materiality analysis was undertaken using a high winter’s day demand scenario.

Leaks that are under 5mm in size do not contribute to the probability of a fire or explosion but will contribute towards total gas volume leaked. Therefore, unlike Significant leaks, decreasing the hole size for a minor leak from 1mm to 0.5mm will only decease the total leaked volume, not the probability of a fatality or injury resulting from fire or explosion (Figure 19).

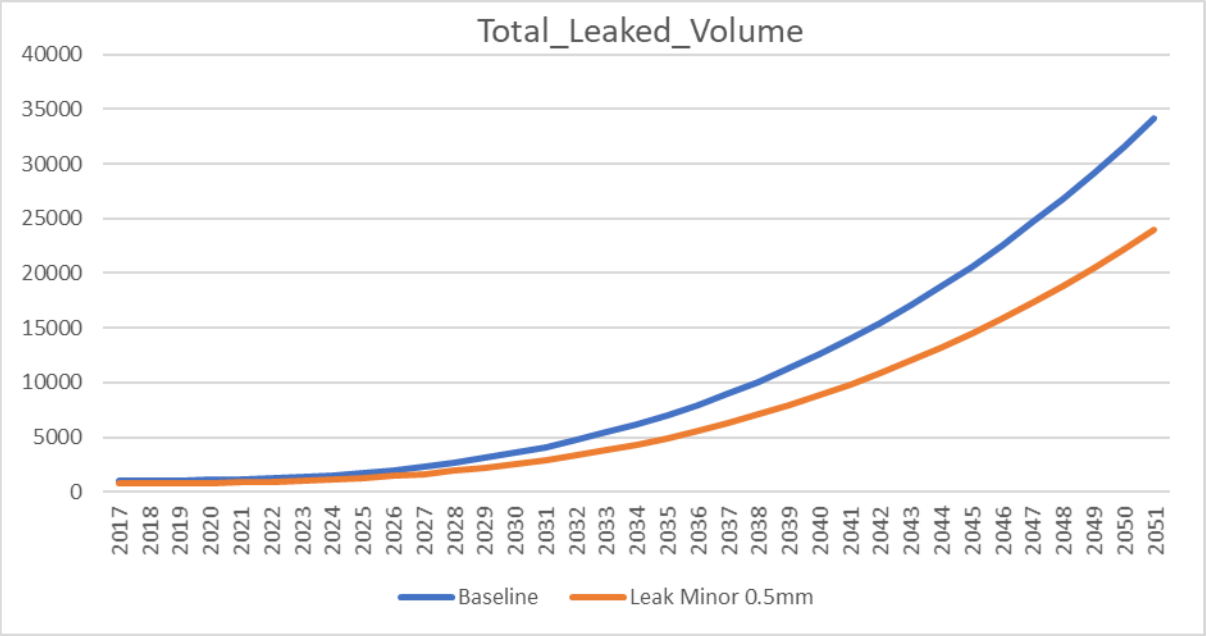

Figure 19: Volume of gas Released from minor leaks (m3/year)

As for significant leaks, minor leaks only contribute a relatively small amount of total leak volume, which is dominated by maintenance activities and compressor ESD vents. Therefore, reducing the size of a minor leak to 0.5mm has an insignificant effect on monetised risk.

In terms of proactive investment, reducing the volume of gas released from a minor leak reduces the deterioration in Environment therefore a small reduction in the required levels spend under the stable service risk scenario by 2051.

### 5.2.8. Emergency Shutdown (ESD) Vents

This materiality analysis was undertaken using a high winter’s day demand scenario.

ESD vents arising from unplanned compressor shut-down and recharge are responsible for a significant proportion of gas emissions. Halving and doubling the volume of ESD vents is expected to have significant impact on Environment risk as numbers of vents will deteriorate under a Without Intervention scenario. Figure 20 shows that the social value of gas emitted is highly sensitive to the assumed volume of an ESD vent (minus maintenance emissions, which are modelled separately). Environmental risk forms a significant proportion of total monetised risk, particularly in later years of the planning period. Figure 21 shows the impact of differing ESD vent volumes on total monetised risk.

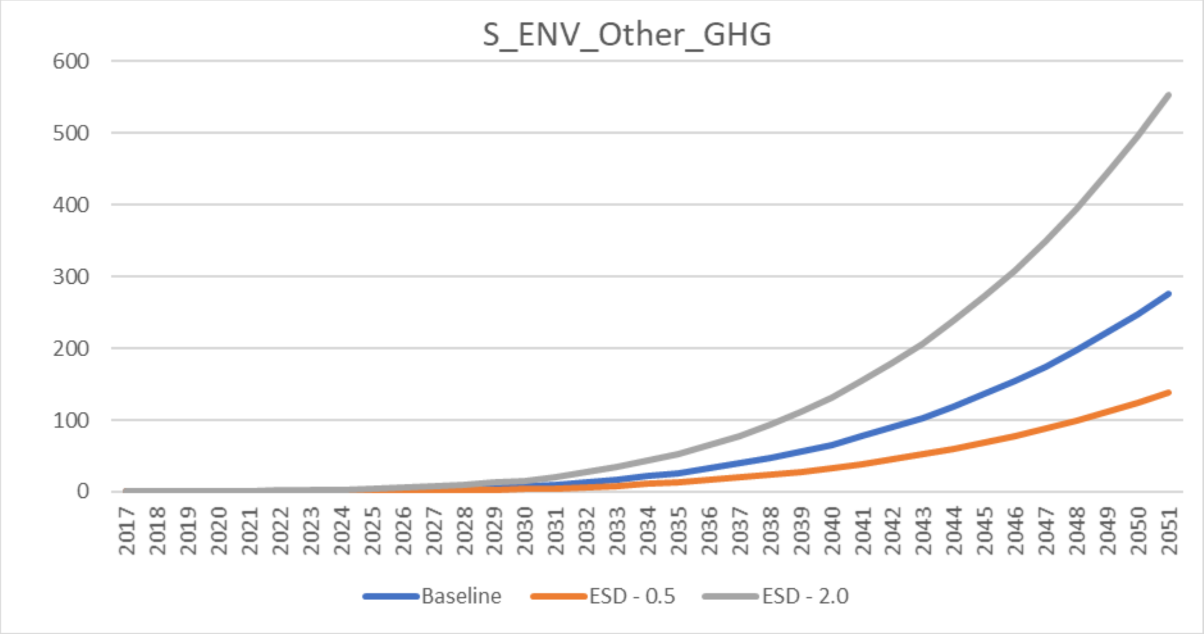

Figure 20: Impact of ESD vent volume on the social value of gas emitted (£m/year)

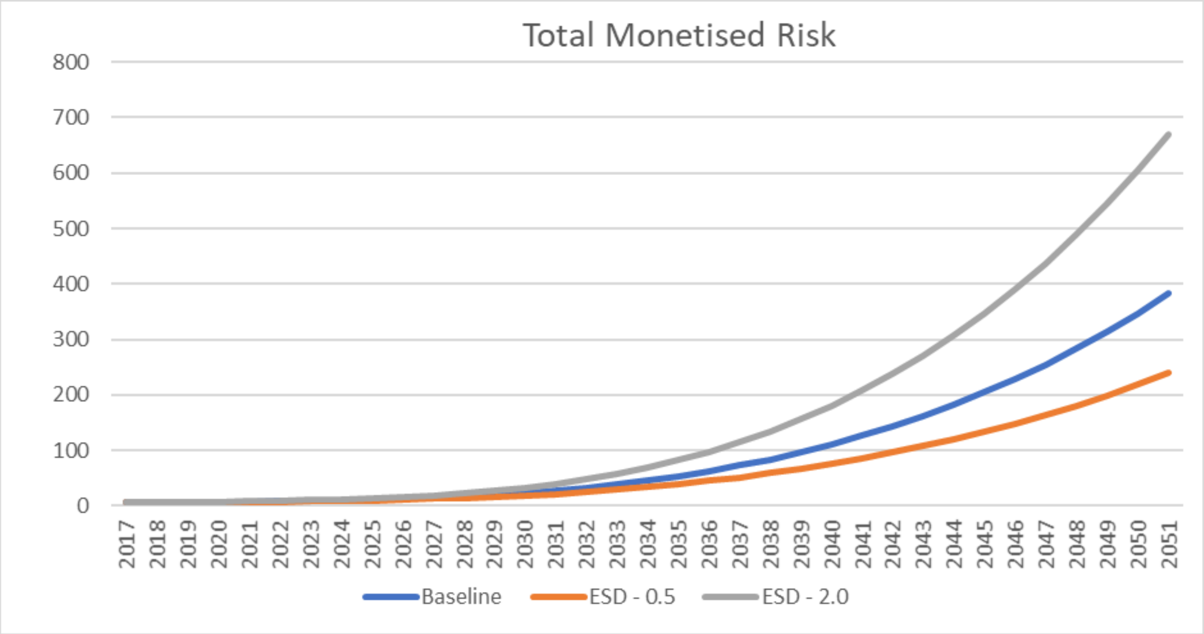

Figure 21: Impact of ESD vent volumes on total monetised risk (£m/year)

The level of proactive investment is initially insensitive to the absolute level of risk. However, post-2028 when only cost-beneficial investments are chosen doubling the ESD vent volume means that additional investments are chosen, as investment benefits are greater, and the level of proactive investment levels are greater for the x2 scenario. Proactive investment is insensitive to lower ESD venting rates.

### 5.2.9. Future Energy Scenarios (Long Term Demand Impact on Risk)

This materiality analysis was undertaken using a 1 year in 20-year demand scenario.

The impact of alternative FES scenarios was tested assuming the level of AR risk is directly proportionate to NTS demand, which is a simplistic but reasonable assumption for these extreme value tests. The FES scenarios tested are shown in Figure 24 below. A linear profile of demand increase/decrease between 2017 and 2041 was assumed.

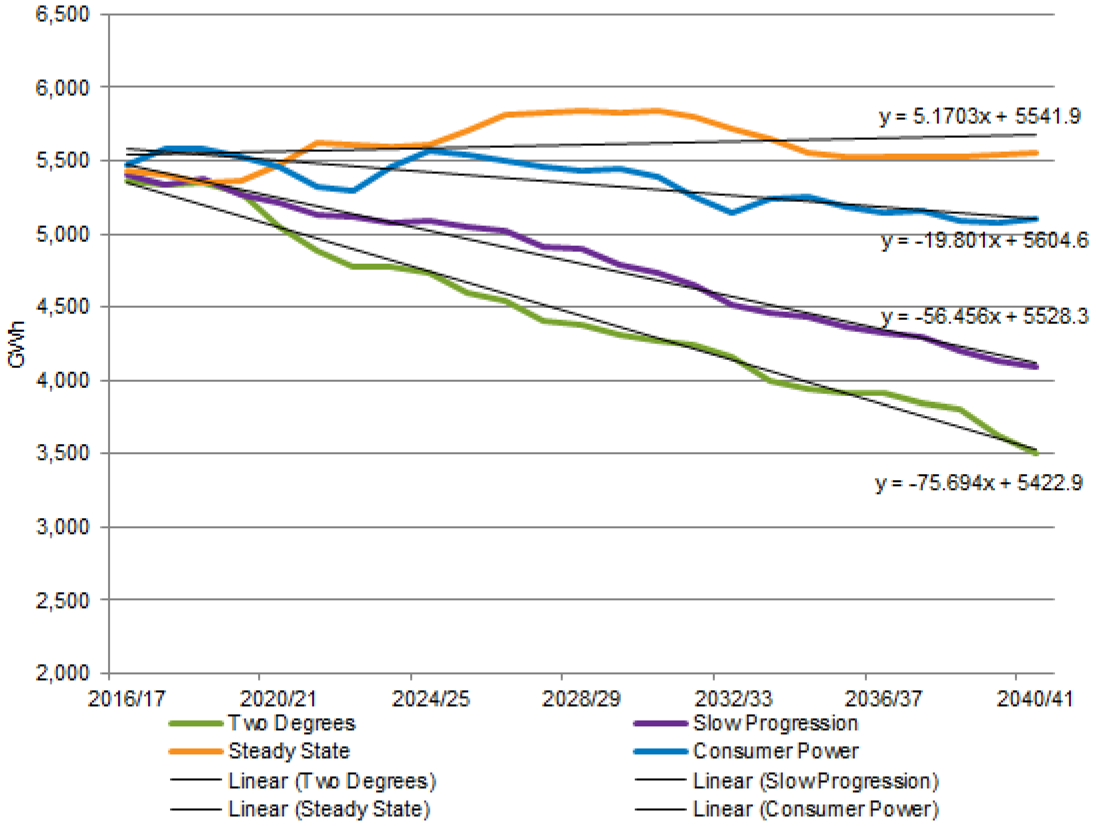

Figure 22 - FES scenario predicted gas demands, including the linear extrapolation used to predict future monetised risk

As FES scenarios only run to 2041, monetised risk and investment analysis was only carried out between 2017 and 2041.

When the TMR values in 2041 are compared against the Slow (Steady) Progression scenario as a baseline, only small differences are seen (Table 15). AR monetised risk is more sensitive, with the Steady State scenario generating 32% more AR risk in 2041 than the Slow (Steady) Progression FES scenario. The choice of FES scenarios is not sensitive to the overall level of NTS monetised risk (or investment) as AR risk remains a relatively small proportion of TMR. As time progresses, the AR risk becomes more sensitive to the adopted FES scenario, which could potentially have an impact on localised investment decisions (e.g. Isle of Grain). This sensitivity will be tested as future versions of FES are released.

We will continue to review the sensitivity of FES demand projections through future reviews of the NOMs Methodology.

| Demand Scenario | Total Monetised Risk Difference 2041 | Availability and Reliability Risk Difference 2041 |
|---|---|---|
| Two Degrees | -0.34% | -8.2% |
| Steady State | 1.35% | 32.0% |
| Consumer Power | 0.75% | 17.9% |

Table 15: Percentage difference in total monetised risk in 2041 compared to Slow Progression scenario

As would be expected given that TMR has not changed significantly, investment levels are similar under the stable service risk scenario.

## 5.3. PIPELINES OUTCOME TESTING

Excluding external interference, which is the highest risk to the pipeline network but is non-condition driven and remains constant over time, the Pipelines risk model profile is dominated by corrosion risk and we have focused our testing on this element of the modelling. The corrosion modelling process is explained in the Probability of Failure supporting document[15] and is complex. In summary:

- A corrosion defect is detected through ILI surveys
- The defect grows at a rate determined by the performance of the cathodic protection system at that location
- The cathodic protection deteriorates over time, without proactive investment
- Therefore, the rate of corrosion defect growth increases over time
- As the pipeline approaches 100% wall thickness loss the probability of a failure of a leak increases (we assume that corrosion leaks cannot cause ruptures).
- When a leak does occur, there are Safety, Environment and Availability consequences

In the sections below the overall rate of risk can be seen to increase steadily without proactive interventions, but there comes a point where many corrosion leak failures are predicted occur and risk levels rise rapidly. This is resulting from the failure of the cathodic protection systems which then allows the rate of corrosion defect growth to accelerate and ultimately pipeline integrity is lost.

Pipelines outcome testing has focused on total monetised risk (TMR) valuation rather than impact on investment planning. This is because investment in Pipelines is driven by compliance with Pressure Systems Regulations (PSR) rather than monetised risk reductions. However, a monetised risk based approach will be used to target investment within the constraints of PSR, but this is outside the scope of this document. As per Sites we have generally used The TMR under a without intervention (to compare the risk values using the “double” and “halve” expected value approach

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[15] Section 4.3

### 5.3.1. Availability & reliability consequences

This materiality analysis was undertaken using a 1 year in 20-year demand scenario.

The sensitivity of overall risk to changing the availability and reliability (AR) risk was tested by doubling and halving the likelihood of an outage resulting from failure, which is specific for each pipeline section. Table 16 shows that the model is not sensitive to gross changes in the overall level of outage risk under a stable service risk scenario.

| Scenario | Difference in TMR 2051 |
|---|---|
| LOS x0.5 | -0.54% |
| LOS x2 | 2.6% |

Table 16 - Impact of increasing the probability of an outage on TMR by 2051 under stable service risk scenario

The AR risk sensitivity was further tested by multiplying the probability of loss of supply (LOS) to a point further down the pipeline. The assumed resilience factors provided by multiple pipeline feeds are as follow:

- Single feed – 100% chance of a LOS
- Dual feed – 1% chance of a LOS
- Triple (or more) feeds – 0.1% chance of a LOS

These are rules of thumb and could be improved in the future by hydraulic modelling of individual pipeline sections.

In the case of there being only one feeder towards a point downstream, the probability of LOS cannot exceed 1 or go below one as there will always be loss of supply, so for comparing AR all other probability values were doubled (e.g. dual feed now has 2% increase in a LOS failure). The outcome of these was measured by number of supply incidents per year and change in monetised risk. Table 17 shows the change in monetised risk in 2051 compared to a baseline reactive maintenance only scenario (AR x 1):

| Scenario | Difference in Total Monetised Risk 2051 | Change in likelihood of a LOS event |
|---|---|---|
| AR x 0.5 | -0.00129% | -0.39% |
| AR x 2 | 0.00259% | 0.78% |
| AR x 4 | 0.00776% | 2.33% |

Table 17 - Impact of different pipeline resilience assumption on TMR and outages by 2051

This illustrates that the model is relatively insensitive to an increase in the probability of a LOS event at resilient locations.

### 5.3.2. Number of people at risk within hazard zones

This materiality analysis was undertaken using a high winter's day demand scenario.

Table 18 shows the impact of changing the numbers of people at risk within each hazard zone around the pipeline on monetised risk and predicted numbers of fatalities, respectively. This is the same test as effectively increasing/decreasing the population count and a surrogate for changing the size of the hazard areas.

| **Scenario** | **Change in TMR** | **Change in number of fatalities** |
|---|---|---|
| People Per Property x2 | 0.43% | 100.00% |
| People Per Property x0.5 | -0.22% | 0.00% |

Table 18 - Impact of assumed numbers of people at risk on TMR and outages by 2051

Doubling and halving the people assumed to live in each property has a linear and proportional effect on the number of fatalities and a similar impact on TMR. However, the distribution of risk will change depending on the population density at specific locations in the network. The change in TMR is relatively low as the Pipelines model is dominated by Environment risk in 2051.

### 5.3.3. Gas leak and rupture volumes

This materiality analysis was undertaken using a high winter's day demand scenario.

As all failure modes link into the Leak and Rupture failure nodes, the impact to changes in these were explored. Tests were carried out on the following factors which all influence the volume of gas lost from the network:

- The distance between block valves
- The leak run time assumptions
- The assumed hole size for corrosion leaks

The block valve distance is used to calculate the volume of gas that needs to be purged from the network to depressurise and effect the repair following isolation of the network. The leak hole size influences how much gas is lost at a fixed pressure and leak duration. A rupture "leak size" is fixed as the pipeline diameter.

Table 19 shows the percentage change in TMR when the assumed distance between block valves is varied. The assumed distance between block valves has a material impact on the levels of TMR in 2051 for leak repairs. Block valve distance is much less sensitive for ruptures as they are much lower frequency events.

| **Scenario** | **Change in TMR – Leak Repair** | **Change in TMR – Rupture Repair** |
|---|---|---|
| BV Distance x0.5 | -12.50% | 0.0000089% |

| | | |
|---|---|---|
| BV Distance x2 | 25.01% | -0.0000045% |

Table 19 - Impact of distance between block valves on TMR for a leak and rupture repair

Table 20 shows the change in TMR when leak and rupture run times are varied. The assumed leak run time has a material impact on the levels of TMR in 2051. Rupture run time is much less sensitive as ruptures are much lower frequency events.

| Scenario | Change in TMR – Leak Run Time | Change in TMR – Rupture Run Time |
|---|---|---|
| Run Time x2 | 74.98% | -0.0040% |
| Run Time x0.5 | -37.49% | 0.0081% |

Table 20 - Impact of the leak and rupture run time assumption on TMR in 2051

Table 21 below summarises the percentage changes in TMR resulting from a change in the leak hole size from 40mm (see Section 7.3.6) to a lower value. The assumed leak hole size as a material impact on the levels of TMR in 2051.

| Scenario | Change in TMR |
|---|---|
| Hole size 20mm | -56.34% |
| Hole size 5mm | -73.83% |

Table 21 – Impact of different leak hole size assumptions on TMR in 2051

In summary, all factors influencing the rate of gas loss from the network have a material impact on TMR in 2051. The impact in earlier years of the planning period will be much less significant as the growth in numbers of predicted corrosion leaks does not accelerate until after 2035 under a without intervention scenario.

### 5.3.4. Cathodic protection and corrosion defect growth rates

This materiality analysis was undertaken using a high winter's day demand scenario.

The rate of growth of corrosion defects is dependent on the performance of the cathodic protection (CP) system. The CP system protection is classified as high, medium or low (see Section 7.3.4), all of which have different levels of corrosion growth. The impact of changing this rate of corrosion growth was tested by independently changing the assumed high, medium and low protection rates. Table 22 shows the impact on TMR of changing the High, Medium and Low corrosion rates independently, while keeping the others rates constant. This illustrates which banding of corrosion growth has the most significant impact on TMR in 2051.

| Scenario | Change in TMR |
|---|---|
| High Corrosion x 2 | 464.74% |
| High Corrosion x 0.5 | -92.98% |

| | |
|---|---|
| Med. Corrosion x 2 | 346.26% |
| Med. Corrosion x 0.5 | -13.05% |
| Low Corrosion x2 | 0.02% |
| Low Corrosion x 0.5 | 0.00% |

**Table 22 – Impact of changing corrosion growth rates on TMR in 2051**

High and Medium corrosion rates have the greatest impact on TMR as most pipelines will be occupying these corrosion rate bands growth during the later years of the planning period when corrosion growth is most aggressive due to lack of proactive maintenance. The assumed corrosion growth rate is also highest in these bands. The impact on TMR is not linear as the time taken for corrosion defect to appear to appear is dependent on all three corrosion rates and the rate of movement between them (see below).

In summary, the TMR is highly sensitive to the assumed corrosion growth rates. However, the base values used are industry standard assumptions and no current evidence exists to use alternative values. This an area for future industry research.

### 5.3.5. Deterioration of the cathodic protection system

This materiality analysis was undertaken using a high winter’s day demand scenario.

The assumptions made to estimate the deterioration in the CP system (which also implies the rate of deterioration of the CP protection, or the rate that the model moves between Low, Medium and High CP protection bands) is discussed in Section 7.3.4 and the expert review. Initially a deterioration rate of 23 mV year was assigned, based on the assumed life of a CP system. This produced a very high number of major corrosion detects which did not correspond with the actual numbers identified and resolved through the ILI process. A rate of 9 mV was chosen was this approximated most closely to the actual rate of major corrosion defect appearance (Section 7.3.5).

To test the impact of CP system deterioration, the deterioration rate was changed from its base value of 9 mV to 18 mV, 23 mV and 28 mV. A value lower than 9 mV was not tested as it was shown not to make significant difference to the modelled number of corrosion defects. Table 23 shows the impact of difference CP deterioration assumptions on MR and the number of predicted corrosion defects by 2051 (all corrosion defects, not just major defects that we would investigate and resolve).

| Deterioration Rate (mV/year) | Change in TMR | Change in Defects |
|---|---|---|
| 18 | 100.50% | 16.38% |
| 23 | 171.30% | 41.97% |
| 28 | 238.89% | 67.43% |

**Table 23 - Impact of changing corrosion protection deterioration rates on TMR and defect numbers in 2051**

The sensitivity of the CP deterioration rate assumption was further tested by calculating the proactive investment spend was calculated using our risk optimiser for four different rates of deterioration under a stable service risk scenario (Table 24). Our base assumption is a CP deterioration rate of 9 mV per year (Section 7.3.5).

| CP deterioration rate (mV/year) | Change in Proactive Investment |
|---|---|
| 9 | 0% |
| 18 | 336% |
| 23 | 447% |
| 28 | 524% |

**Table 24 – Change in proactive investment spend by 2051 when compared to base 9mV/year CP deterioration scenario**

The assumed rate of CP deterioration is highly sensitive to the proactive spend required to manage pipeline risk as this rate modifies the assumed life of the CP system (before replacement is needed) and the rate of occurrence of major corrosion defects that must be investigated and repaired to prevent leaks.

The model is highly sensitive to the assumed rate of CP system deterioration as it directly influences the numbers of unresolved major defects under a no intervention scenario, which ultimately leak with associated Financial, Safety, Environment and Availability consequences. A leak impacts on multiple service risk measures, with an associated MR increase. This explains why the rate of increase in TMR is greater than the rate of increase in the numbers of defects.

### 5.3.6. Alternating Current (AC) induced corrosion

This materiality analysis was undertaken using a high winter’s day demand scenario.

The increased corrosion risk associated with pipelines close to overhead power cables (AC source) is discussed in Section 0 and the expert review. We assume a simplistic 20% uplift in the rate of corrosion growth at these locations. To test the sensitivity of this assumption this was increased to 40% and reduced to 10%.

Table 25 shows that changing the 20% base assumption has a minor impact on TMR, which suggests that the AC interference factor has a small impact on the numbers of leaks resulting from higher or lower corrosion defect growth rates.

| Scenario | Change in TMR |
|---|---|
| AC interference 40% | 1.28% |
| AC interference 10% | -0.61% |

**Table 25 - Impact of changing AC interference factor on TMR in 2051**

### 5.3.7. Ignition of leaks and ruptures

This materiality analysis was undertaken using a high winter's day demand scenario.

The probabilities of a gas ignition and fire/explosion following a leak or rupture are discussed in Section 7.2.8 and the expert review. These are industry standard assumptions[16].

To test the sensitivity of these values, the base probabilities for leak and rupture ignition were multiplied by 2.0 and 0.5 respectively. Table 26 shows the impact of changing ignition probabilities on TMR and predicted fatalities.

| Scenario | Change in TMR | Change in Fatalities |
|---|---|---|
| Leak Ignition x2 | 0.4325% | 99.99% |
| Leak Ignition x 0.5 | -0.2162% | -49.99% |
| Rupture Ignition x2 | 0.0001% | 0.01% |
| Rupture Ignition x 0.5 | 0.0000% | -0.01% |

**Table 26 - Impact of changing ignition probabilities on TMR and fatality numbers in 2051**

The number of predicted fatalities from corrosion leaks is linearly related to the leak ignition probability. The Safety risk is therefore highly sensitive to the leak ignition assumption. There is only a minor impact for rupture ignition probability as most the Safety risk in 2051 is associated with corrosion leaks (external interference is the main source of rupture risk and this stays fixed over time). There is only a minor impact on TMR in 2051 as a significant proportion of TMR relates to Environment and Availability risk in 2051.

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[16] IGEM TD/2 Edition 2

## 5.4. SUMMARY OF MATERIALITY TESTING

### 5.4.1. Monetised risk sensitivity

For Sites and Pipelines, the factors most influencing TMR over the RIIO-T2 period are Environment risk and levels of unburned gas emissions. These risk values are based predominantly on the following input variables:

- ESD vent numbers
- Leak flow rates assumptions (e.g. corrosion hole size)
- Leak run times
- Leak hole size assumptions and pipeline pressures
- Cathodic protection deterioration assumptions (rate of CP system deterioration and the impact on defect growth rates)

Work to improve the ability of the models to predict absolute levels of monetised risk will focus on these variables.

### 5.4.2. Investment planning & risk trading sensitivity

In terms of future investment levels, then sensitivity depends upon the investment scenario that is being modelled. For scenarios that are required to achieve stable levels of service regardless of economics, investment levels are insensitive to the absolute level of risk. However, cost beneficial investments are sensitive to absolute risk levels and risk deterioration.

There is a double inflationary effect on gas volumes under a no proactive intervention scenario, which causes Environment risk to increase more quickly that other service risk measures. The double inflationary risk consists of:

- Increases in numbers of failures and failure consequences over time
    - Deterioration assumptions for Sites assets
    - Corrosion rates and corrosion deterioration assumptions for Pipelines
- Carbon inflation (increasing value of carbon over time)[17]

Work to improve the ability of the models to support investment planning and risk trading will focus on these factors.

For Sites, the primary non-financial driver for future proactive investment is Environment risk as this carries the highest levels of monetised risk in later years of the planning period. Availability risk is currently not considering the Safety risk associated with a wide-scale gas outage or the societal costs of breakdown in the gas trading market, and as such is not a major factor driving TMR or investment.

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[17] Service Risk Framework supporting document, Section 5.5

For Pipelines, Environment and Availability risk do drive proactive investment levels as rapidly increasing numbers of leaks and ruptures will cause wide-scale outages as well as huge levels of carbon emissions under a no intervention scenario.

Availability and Reliability risk sensitive factors are discussed further in Section 7.

# 6. EXPERT REVIEW

## 6.1. APPROACH

Building the Methodology and models has required us to make many assumptions as the data or evidence is not always available. Reasons for this include:

- The monetised risk approach is new, and we (or the wider industry) have not always collected the data needed to support it. An example of this is root causes of failure
- Some events are rare, or have possibly never occurred therefore judgement or extrapolation is required to derive annualised frequencies of occurrence. An example of this is corrosion leaks on the NTS, or explosions at sites
- Research is ongoing, or evidence may be contradictory. An example of this is proportions of people killed or injured at differing proximities from the fire or explosion

Our risk models, which underpin our Methodology, were built by asset management consultants, who did not have specific gas industry knowledge. They were supported by many gas engineering experts, both internal and external to NGGT who helped our consultants to identify the best sources for information or make judgments as to the best values or assumptions to use.

The purpose of the expert review was to allow independent experts to review the inputs and outputs to the final versions of the models and to comment criticality on these. The review was carried out by the authors of the UKOPA Product Loss, Incidents and Pipeline reports[18] and have vast experience in the gas industry. The expert review process can be summarised as follow:

1. The expert reviewers became familiar with the NGGT NOMs Methodology
2. Workshops were held to demonstrate how the models worked and what outputs could be produced
3. The expert reviewer devised a scope of work, which was agreed (Appendix D)
4. A data request was submitted and several model output reports were generated to allow the expert reviewers to undertake offline comparison and benchmarking
5. Further workshops were held to clarify data and identify further questions/challenges
6. Initial presentation of findings to NGGT allowed clarification of some of the data and assumptions made
7. Draft report issued and comments addressed
8. Final reporting, which was shared initially with Ofgem

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[18] http://www.ukopa.co.uk/published-documents/ukopa-reports/

Sites and Pipelines models were reviewed separately. The conclusions and recommendations of each are included below, along with the NGGT response.

Following the initial review, further work was required to validate and test the sensitivity of the supply and demand models used to calculate Availability risk. This is discussed in Section 9. A follow-on expert review was arranged and a report produced. The summary conclusions discussed in the remainder of this section take account of both the original and follow-on expert reviews.

## 6.2. SITES

### 6.2.1. Conclusions

The following conclusions are drawn from the expert review of the AIM sites model:

1. The AIM Sites model incorporates all the assets recorded in the NGGT Ellipse asset database, and assigns failure modes and the failure mode consequences that relating to the Service Risk Framework. The model provides a detailed and comprehensive representation of all the NGG site assets recorded in Ellipse.
2. The input to the model includes the current asset condition, the associated faults and base maintenance records. The asset condition deterioration is based upon accepted models and expert operational experience which represent best practice.
3. The AIM sites model uses all the asset data in Ellipse and is aligned to the Ellipse hierarchy. The Equipment Group Identifiers have been linked to the Sub Process Failure modes. The inclusion of all the Ellipse data means many electrical assets are included in Ellipse. these are treated as consumables and have little or no risk to the service framework (e.g. Radio handset, Switch, Relay)
4. The AIM sites model risk map, which relates the asset data failure probabilities and consequences and the associated costs to the defined NGG service measures, accurately represents the relationship between the risk of gas releases, fires and explosions and the service risks.
5. Failure rate data and proportion of each failure mode is based on the Offshore Reliability Data (OREDA) handbook and the AGI Safe Manual. OREDA is recognised as the most comprehensive source of equipment failure data, and the AGI Safe Manual applies UK data published by HSE to NGG assets. These data sources are the best available. Site level and asset level comparisons of AIM sites model predictions with the published data were found to be reasonable.
6. The total number of gas releases, fires, explosions and fatalities and injuries predicted by the AIM site model for all NGG sites was compared with normalized industry data. There is no source of published data for assets equivalent to NGGT sites, so accurate comparisons were not possible. However, the comparison with normalised industry data indicates the AIM sites model predictions show reasonable agreement with a range of industry incident rates. The comparison identified the AIM sites model would benefit from the addition of a modification to the prediction of the numbers and sizes of leaks, and inclusion of a model to estimate leaks from pipework and flanges, the prediction of pressure system failures and the prediction of failures resulting in sudden, uncontrolled releases.

7. A detailed review of the loss of supply consequences model incorporated in the AIM model has identified several recommended changes to improve the accuracy of the predictions.
8. The AIM sites model results are intrinsically linked to the Ellipse asset data and its structure, the input fault history and maintenance records, and the asset condition modelling which is based on industry models and experience, all of which are inputs to the model. Inaccuracies in the AIM sites model predictions are therefore influenced by anomalies and inaccuracies in these inputs. Further studies and sensitivity tests could be carried out to assess the materiality of any errors in these data sources.

### 6.2.2. Recommendations

It is recommended that:

1. A series of structured sensitivity studies are carried out to confirm that the key primary and secondary asset types which influence the service measure risks are mapped correctly to systems, and failure modes and service consequences to minimise scatter or noise in the prediction of monetized risks.

**NG Response S1**. There are limited numbers of NTS service failure consequences (events) that occur in sufficient volumes to reliably validate all failure modes and proportions. The observed defect rate forms an input to the model, but relatively few produce observable consequences. The validation report uses compressor trips and ESD vents and leaks to show that the model is performing reliably for what are relatively frequently occurring events, but for low frequency events (Section 7.2) it must be assumed that the OREDA and AGI SAFE proportions (defects becoming failures) are correct until further data/evidence becomes available. A wider benchmarking exercise with international gas transmission companies may be carried out through ongoing Methodology improvements (Section 10.1.2, Action 1.12).

2. Consideration should be given to removing or disabling some of the electrical equipment which has little or no impact on service risk (e.g. radio handset, switch and relay) to allow a greater focus can be placed on the key assets which influence the service measure risks.

**NG Response S2**. All assets carry risk, even if just the financial cost of repair and maintenance. For small electrical assets, only the increased repair/maintenance costs associated with asset condition deterioration contribute to future risk reporting and investment decisions (fixed costs are not considered). Our current design principle is to include all assets in our NOMs Methodology and allow the probability of failure, consequence of failure and service risk framework to calculate the actual level of risk. Removing assets arbitrarily is not consistent with our stated design principles, but could be revisited in the future through ongoing Methodology improvements

3. Following discussions with an external expert, it is recommended that a review of the modelling of public fatalities and injuries external to sites is carried out to ensure AIM sites model predictions take account of the site QRA results. NTS sites are in remote

areas and designed to minimise the possibility of failure consequences extending beyond the site boundary.

**NG Response S3**. We assume that only explosions (not fires) have a risk on public health and safety (outside of the site boundary). These are predicted to occur very infrequently therefore the annualised risk to loss of life is small. We recognise that using QRA analysis from specific sites will improve the analysis, particularly at larger sites or where close to centres of population. We will explore the use of site specific QRAs in future improvements to the Methodology where possible. Zoning is not a concept currently supported by our NOMs models as (Sites) assets have no assigned geographical location and it is not possible to assess their proximity to other assets (other than belonging to the whole site). Therefore, it is not possible (for example) to calculate the proximity from an ignition source.

4. A scaling relationship is applied to the numbers and sizes of leaks for different assets, and a model to estimate leaks from pipework and flanges is developed and incorporated in the AIM sites model. In conjunction with this, the AIM sites model should be extended to include pressure system failures and the associated fatalities and injuries, including catastrophic failures resulting in sudden uncontrolled releases.

**NG Response S4**. A simplistic model for large and small leak failure modes only has been assumed. There is insufficient data available to develop a more specific leak size model for different asset types. We will explore the potential to do this through improvements to the Methodology as assumed leak size (and associated gas flow rates) are sensitive (Section 7.2.7).

Leaks from pipework and flanges are included as corrosion failure modes from above and below ground pipework. Other shrinkage is included in a general emissions risk node which ensure that the emissions volumes predicted by our models are consistent with RRP reporting.

Pressure systems failures were not identified as a significant failure mode during the development of the Methodology and there is no available data to reliably predict the arising safety risk at asset level. Again, we will explore the incorporation of pressure systems failures through future Methodology improvements. As a fatality through a pressure systems failure is possibly more likely than an explosion we recognise it represents a limitation, but is likely to only have a small impact on monetised risk and investment.

5. The supply demand scenarios used to predict supply loss consequences should be based on the 1 in 20 years' peak winter, as there is a legal requirement to design for these conditions. In addition, in predicting the future performance of NGG assets, the AIM models should model the probability of 1 in 20-year peak winter conditions within the modelling period and consider at least 3 supply scenarios.

**NG Response S5**. We have updated the analysis to use a 1 in 20 peak demand scenario. We have considered a range of different options, including stressed terminal flows at St Fergus, Bacton, Milford Haven and Easington. We also sensitivity tested alternative Future Energy Scenario (FES) base years (2021 and 2025). See Section 9 for details. The sensitivity of the choice of FES scenario upon monetised risk and investment was also explored (Section 5.2.9).

6. Consideration should be given to using the same methodology used by System Operations in the Ten-Year Statement to evaluate the importance of each compressor unit and compressor site and how they will benefit the network in the future.

**NG Response S6**. See NG Response S5. We are now aligned with the Ten-Year Statement methodology.

7. NGG should also consider consulting the Distribution Networks and request they validate the assumptions made in the methodology to ensure the flow can be swapped for all demand scenarios including the peak 1 in 20 winter.

**NG Response S7**. As we are now using a 1 in 20 peak demand scenario it is unlikely that the ability to flow swap will exist (as Distribution Networks will also be dealing with high gas demands). The flow swap factor, which reduced Availability risk, has now been removed from our analysis (Section 9.2.3).

8. Consideration should be given to simplifying the methodology by applying a standard financial impact to all block valves and differentiating between sites which have above ground main pipeline or interconnecting pipework and those which have a simple H block underground connection. In the interim the current model should be reviewed alongside a network map to ensure the correct configuration has been applied.

**NG Response S8**. We consider this recommendation to be a minor adjustment to an element of the Methodology that requires a much greater level of sophistication. We have shown that the exclusion of block valve risk has a minor impact on monetised risk (Section 5.2.5).

Modelling the impact of supply-demand consequences is highly complex. The model we have used is simplified based on an expert view of network connectivity and impact of asset failure on supply outage. A risk-based tool which can model alternative supply and demand scenarios, models hydraulically the impact of each asset failure and fully consider the likelihood of different supply and demand scenarios occurring over space and time, is needed to fully understand and test loss of supply consequences of asset failures, individually and in combination. We are exploring the development of such a risk-based tool, but this will not be available in time for our initial NOMs Methodology approval. Incorporation of more sophisticated supply-demand risk assessments will be considered as part of ongoing improvements to the Methodology. We do not believe that the recommendation would improve the current approach significantly as further assumptions would be needed to apply the suggested simplifications.

The connectivity applied in the model is based on subject matter expert (SME) knowledge and opinion. We have undertaken a further validation of connectivity as part of improvements to Availability risk modelling, but these connectivity assumptions remain subjective until a full hydraulic modelling approach is adopted.

9. The supply loss consequences prediction methodology should be extended to take account of the impact that a loss of an Entry Point would have on all stakeholders. The model currently does not take into consideration the suspension of the gas market and restriction of supplies to the public and industry. This would have a significantly greater financial impact than the compensation payments which are currently modelled. The model currently does not evaluate the risk to the public as a result of no gas and a loss of heating which could have a significant health risk upon vulnerable citizens.

**NG Response S9**. We concur that this is a limitation of the existing approach. Quantifying this impact, which would be different for all supply-demand scenarios and would also need to consider the economics of the global gas market would be 1) highly complex 2) likely to add significantly to monetised risk. We would consider this to be out of scope at this stage, but would welcome further discussions with Ofgem.

We also point out that the potential loss of life that could occur given a wide-scale gas outage is also not modelled, which could potentially increase the monetised risk of a supply outage by orders of magnitude.

10. The methodology has the capability of evaluating the impact of the loss of part of a site, stream or unit, however this is currently only used for individual compressor units. The model could be improved by the inclusion of a loss of resilience factor for the loss of a stream or part of the site which could be used as a scale factor for the loss of supply consequence cost.

**NG Response S10**. This is a valid recommendation, but we cannot currently fully quantify the resilience benefit offered by each individual site in the NTS. This requires a risk-based, supply-demand scenario model to be built, as per NG Response S8. Understanding the contribution of each asset to the availability of each individual site is also complex, potentially using a Reliability, Maintainability, Availability (RAM)-type approach, which will be site specific. Our NOMs Methodology and models are designed for strategic planning and reporting. Further sophistication is possible, but may require data and analysis from specialist external systems, such as hydraulic and reliability modelling. Whether we decide to develop and incorporate site-specific RAMs through the NOMs Methodology in the future is dependent on materiality of the impact on monetised risk and investment value.

## 6.3. PIPELINES

### 6.3.1. Conclusions

The following conclusions are drawn from the expert review of the AIM pipelines model:

1. The AIM pipeline model has been constructed using the detailed data extracted from the NGG UPTIME system, which is a GIS tool providing the spatial location of the pipeline sections, supplemented by asset data from the NGG Ellipse asset database. These data sources represent the best available data, so the AIM pipeline model is both extensive and comprehensive. In constructing the model ICS identified several data gaps and difficulties linking data between these two sources which have been addressed data obtained from the Pipeline Data Book and applying appropriate assumptions.

2. High pressure gas pipelines are designed in accordance with the pipeline standard IGEM/TD/1, which requires the pipeline route is classified as rural or suburban per an assessment of the population associated with occupied buildings in the pipeline route corridor, and the pipeline is designed per the classification. The IGEM/TD/1 definitions of rural and suburban areas and the impact of pipeline design on the consequences of failure are not included in the AIM pipeline model. As building and population infringements are identified in the 4 yearly TD/1 route surveys, subject to risk assessment and any required mitigation installed, the reduced hazard zones which apply to S Area pipelines could be applied in locations of high population density.

**NG Comment P1**. The IGEM/TD/1 Rural/Suburban classifications are not available in a form that could be easily applied to the model. We have mitigated this by applying the correction factors suggested by the independent expert review. Also, by splitting the pipeline network into 12-metre sections we can model the highly-localized failure impact on properties which provides greater confidence in consequence of failure calculations

3. The AIM model uses recognised pipeline damage and failure modelling and best available published pipeline fault and failure data to bench mark and scale the predicted the number of leaks and rupture failures. The current predicted failure rates compare well with published data, which confirms the scaling approach is acceptable. Revised benchmark coefficients have been derived which improve the predicted rupture rate. Other approaches could be adopted to take account of different pipeline integrity management and intervention philosophies and system ageing.
4. The primary damage risks to NTS pipelines are external corrosion and external interference. The AIM pipeline model applies best practice in modelling damage and failure due to corrosion and external interference. The incidence and growth of external corrosion is of importance as the pipeline system ages. Future improvements relating to modelling of the impact of alternating and direct current induced corrosion have been recommended. The resistance to corrosion is assessed using CIPS data. Where gaps in this data exist, a medium corrosion rate is applied, which may underestimate growth in locations of inadequate protection.

**NG Comment P2**. A medium corrosion rate was assumed to avoid potentially under or overstating risk. This data will continue to improve as further CIPS surveys are completed

5. The pipeline standard IGEM/TD/1 places a limit on the maximum population density in R areas, and requires there are no occupied buildings within the R and S area building proximity distances. Compliance with IGEM/TD/1 requires that pipeline route is regularly audited to identify population and building infringements, which are then subject to QRA to confirm whether the risk is acceptable or mitigation measures are required. The AIM model applies a population density in the vicinity of the pipeline based on the MSOA data obtained from the dataGov website and applied for a distance of 8 times the building proximity distance either side of the pipeline, which overestimates the population at risk and does not account for pipeline design requirements. Factors to correct this have been suggested.

**NG Comment P3**. We have mitigated this by applying the correction factors suggested by the expert independent review. We are currently exploring the use of OS Mastermap data sets to improve the estimates of properties within pipeline hazard zones (for each 12-metre section). Materiality tests, covering the sensitivity of the assumed population at risk in the event of fires or explosions, are discussed in Section 5.3.2.

6. The prediction of numbers of fatalities is high, both in comparison to historical number (zero) and in comparison, to the number of fatalities predicted in pipeline quantified risk analyses (QRAs). The application of several safety QRA modelling assumptions would reduce the predicted numbers of fatalities to a level which compares more reasonably with safety QRAs.

**NG Comment P4**. As there have been no fatalities due to the failure of a pipeline network, we must make assumptions about the true level of risk. Pipeline QRAs are localized and it is not always possible to apply the same rules to a strategic model covering the whole NTS. We will explore how site specific QRAs can be applied in areas of significant risk through future Methodology improvements. The impact of different numbers of properties at risk within hazard zones has been tested in Section 5.3.2.

### 6.3.2. Recommendations

It is recommended that:

1. In modelling of external corrosion, consideration should be given to applying a high corrosion rate at locations where CIPS data is missing, and improving the modelling of the impact of alternating and direct current induced corrosion.

**NG Comment P5**. The impact of AC interference is still not fully understood. We have applied the assumptions recommended by the expert independent review and this produced very high levels of corrosion growth. We propose to continue with our current 20% uplift until more robust data is available. This 20% assumption has been materiality tested (Section 5.3.6). As stated previously, we believe using a medium corrosion rate to gap-fill missing CIPS measurements is the best approach to avoid under or over estimation of risk.

2. The revised benchmark coefficients derived for scaling the predicted rupture rate should be incorporated in the AIM model.

**NG Comment P6**. The scaling factors recommended by the expert independent review have now been applied to scale the predicted rupture rate

3. Reduced hazard zones basted on S area building proximity distances should be applied at locations of where high population densities in proximity to pipelines have been identifies, in order to take account of the IGEM/TD/1 requirements S area pipeline design.

**NG Comment P7**. Scaling factors have been applied as recommended by the expert independent review. We will further explore the potential to model Suburban and Rural locations in line with IGEM/TD/1 requirements, but available data sets do not currently exist to allow us to do this precisely. The numbers of people at risk of failure is directly proportional to this applied factor and similar conclusions can be drawn as per the materiality analysis carried out in Section 5.3.2.

4. Safety QRA modelling assumptions for the impact of the consequences of failure on the population in the vicinity of the pipeline should be incorporated.

**NG Comment P8**. These QRA assumptions are generally site specific and hard to apply generically across the whole NTS. We will investigate how we could potentially incorporate the principles of QRA modelling assumptions in future revisions to the Methodology, focused on high risk pipelines / locations.

5. NGG should use the AIM pipelines model to assess whether the rate of increase in the number of unplanned interventions as the system ages is increasing to a critical point which could affect network flexibility and supply.

**NG Comment P9**. The Pipelines model is configured to do this already. As the probability of failure increases due to deterioration the predicted impact on supply outage is assessed using an estimate of the number of downstream properties reliant on the capacity provided by each pipeline section. Risk reduction factors are applied to account for network resilience (e.g. multiple feeds) and for where GDNs have options to utilise multiple Offtakes.

6. Further work to validate the predicted number of environmental emissions against the predicted leak and rupture rates and expected response times rates should be carried out.

**NG Comment P10**. The predicted number of environmental emissions is a direct consequence of the numbers of predicted corrosion and rupture events. The volume of gas lost is based on assumptions (from pipelines) experts regarding time to respond and distances between block valves. Leak and rupture flow rates are industry standard assumptions (see Section 7.3.6). Further validation is not possible unless actual leak and rupture events occur. All assumptions have been subjected to materiality testing (Section 5.3.3) and further data collection/analysis work planned if material.

7. Application of a simplified loss of supply consequences model incorporating only pipeline sections between Entry Points, Compressors, Multi-Junction and Exit Points should be considered, as described in the AIM Sites Validation Report.

**NG Comment P11**. See NG Response S8.

# 7. JUSTIFICATION OF KEY MODEL INPUTS

## 7.1. APPROACH

Evidence for validation or justification is presented for all input variables and coefficients that are demonstrated to have a material impact on calculated monetised risk and on investment decision making. Monetised risk is a new concept for NGGT and in some cases evidenced data does not exist or has not been historically collected.

The analysis to confirm which routes through our risk maps are significant (Section 3) and which input variables within each significant route are sensitive has identified several key inputs that are driving monetised risk and (potentially) investment. We have demonstrated that of the several hundred key inputs to our models, for which alternative values could be used, that only relatively few are both significant and sensitive.

The remainder of this section will outline how we believe that we have sufficient confidence to use these values within our Methodology. We will summarise the source of the data and assumptions for each and how the applied values/assumptions are justified. Where there is limited data available to undertaken direct validation of these the following approach has been taken.

- We have referred to where this has been covered by the expert review and any recommendations actioned or required
- We have suggested an indirect approach, such as comparison with previous assumptions
- We have referred to the source of the data, believing this to be the best available information. Much of our Methodology is built using industry studies and assumptions as NGGT specific data does not exist
- We have described the process by which the assumption was made and how this could be improved

## 7.2. SITES

### 7.2.1. Sensitive input variables

As per Section 4.4, the sensitive input variables for the Sites model are as follows. Defects rates and defects deterioration are included as although assumed to be error-free they drive all monetised risk calculations.

- Defects rates
- Defects deterioration
- Emergency Shut Down (ESD) vents
    - <Vent Quantity>
- Volume of gas lost through leaks
    - <Minor Hole Size>
- Likelihood of an ignition given a leak
    - <P_Delayed_Ignition>
    - <P_Explosion_Ignition>
    - <P_Immediate_Ignition>
- People at risk of death or injury
    - <People per Prop>
    - <HS_FATAL_MID_PROPN>

    - <HS_FATAL_INNER_PROPN>
    - <Rural Locations>
- Value of a loss of life or major injury
    - Gross disproportion factor>

### 7.2.2. Defect rates

As discussed previously, raw fault and defect data used as the starting point for PoF calculations is assumed to be error free and is collected through our routine inspection, maintenance and repair processes and captured through our works/maintenance management system (Ellipse). NGGT is ISO55001 accredited and our work management processes, including defects capture, have been extensively audited.

We do not routinely collect the consequences of asset failure and have used the Offshore Reliability Data (OREDA). As described in the expert review this data source is used provide reliability data for a range of offshore oil and gas equipment. Volume 1 of the 2009 edition was used which contains the most extensive range of data for topside equipment most relevant to onshore assets. These failure models and failure mode frequencies were then assigned to specific asset type. This results in approximately 23,000 different asset-failure model combinations within our modelling.

Most potential failures are identified and mitigated before they result in a measurable consequence, which limits our ability to validate this element of the model using observed events. We have identified two events which are sufficiently frequent to compare modelled and actual numbers, which are discussed below:

- Leaks from valves, pipework and fittings
- Emergency Shut Down (ESD) vents

The expert review concludes that the model predictions show reasonable agreement with a range of industry incident rates except for release. The model predicts a high gas release rate, but the industry definition applied for significant leaks is greater than 50 mm diameter and the model is predicting leaks with diameter greater than 5mm, so direct comparisons cannot be made. This may account for the observed difference in predicted number of significant leaks compared to published industry values. The review also recommends that a scaling relationship is applied to the numbers and sizes of leaks for different assets, and a model to estimate leaks from pipework and flanges is developed. Currently, data does not exist to do this and we will consider as part of ongoing business data and modelling improvements.

### 7.2.3. Leaks from valves pipework and fittings

This has increased in recent years, which could be asset deterioration or improved recording of data. These leaks are not classified as significant or minor.

Overall numbers are comparable, but the Ellipse average is possibly too low due to the very low numbers of leaks reported in 2013 and 2014. Numbers of leaks on valves and above ground pipework appear to be low in our models, but it is possible that the Ellipse data set includes smaller, relatively insignificant leaks which would not be directly captured in our models.

In summary, we believe that the numbers of leaks being reported through our modelling is reasonable, but possibly understated. However, any gas losses not being reported through the leak failure mode is captured elsewhere as “maintenance emissions” (Section 7.4) so are not omitted from overall levels of Environment risk.

### 7.2.4. ESD vent numbers

The actual number of ESD vents is highly variable year on year, depending upon compressor usage and the different combinations of compressor units that are required to meet demands under different supply conditions.

We would not expect to be modelled the exact number of annual ESD vents due to the sensitivity to different gas demands and operating patterns so this number is judged to be reasonable.

Over the T2 period (2021 to 2025), the modelled average increases, but planned interventions would be expected to reduce this number.

In summary, although we can directly measure the number of ESD vents from the network it is variable year on year. The model appears to be under-predicting in early years of the analysis, but reasonable during the 2021 to 2025 period over which investment planning will be carried out. As for leaks above, any gas emissions that are missing from ESD vents are rolled into a “maintenance emissions category”, so are not omitted from overall levels of Environmental risk.

### 7.2.5. ESD vent volumes

Includes sensitive variables: <Vent Quantity>

Every ESD vent predicted by the model has an associated vent volume. This volume is assumed to be the same for all ESD vents. ESD vent volume can be calculated directly from reported data so has a good level of confidence.

An ESD vent volume is assumed to be the same as a Planned Vent.

The ESD vent volume is calculated by (assuming Process and ESD vent volumes are equivalent):

**Total Volume of Process Vents / Total Number of Process Vents**

The number of ESD vents (see above) can then be estimated by:

**ESD Vents Total / ESD Vent Volume**

This will vary annually based on the required compressor usage.

### 7.2.6. Defects deterioration

The rate of increase in asset failure, measured by an increase in the number of observable defects is a sensitive assumption for both monetised risk and investment planning. As discussed previously, due to the safety and compliance risk associated with failing to maintain our assets, few are run until failure. This makes the assessment of Without Investment failure rates difficult as historic failure data does not exist to calibrate and validate deterioration models. This is a common problem for safety-critical process industries, and expert elicitation of deterioration rates is routine applied to understand the required levels of maintenance to manage risk[20]. The expert review concludes that the asset condition deterioration is based upon accepted models and expert operational experience, which represent best practice.

As per the Probability of Failure supporting document[21] a standard elicitation approach was used to estimate deterioration rates. Rate for the change of defect rates under a Reactive Only Maintenance scenario. This scenario implies that:

- No proactive investment in asset replacement or refurbishment which would extend the life of the asset
- Maintain assets at the current level condition it would be expected that as assets deteriorate that current maintenance frequencies/approaches would not be sufficient to hold risk stable
- Repair any identified defects, but this repair does not improve asset condition (i.e. repair rates will continue to increase as condition degrades)
- Deterioration curves were estimated for groups of similar assets through expert elicitation workshops. Using the range of responses provided, three separate model types (Weibull or Bi-Weibull) were produced for use in the failure rate analysis:
    - Repairable asset deterioration model (asset can be repaired upon failure with no impact on function)
    - Non-repairable deterioration model (asset must be replaced upon failure)
    - Asset Heath versus Age models, to derive a condition-adjusted age value (Effective Age) using available Asset Health data from condition surveys

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[20] https://theiam.org/knowledge/projects/ssgs/subject-16-reliability-engineering/

[21] Section 5.4

The elicitation workshops were facilitated by external consultants who have undertaken many similar exercises for water, gas and power companies, which is an improvement on the existing Methodology where only a limited number of experts were engaged. The approach is summarised in Appendix D of the Probability of Failure supporting document. This document suggests that some post-validation adjustments to the applied models might be possible, but following review of the outcomes of the elicitation workshops and impact on the performance of our models, we have not made any changes to the Weibull shape and scale values derived from these initial elicitation workshops.

In summary, we have developed an improved elicitation process for our new NOMs Methodology, involving a wide range of asset experts in running elicitation workshops to avoid bias and ensure consistency when providing questionnaire feedback and ensuring that the resulting data is analysed in a statistically robust manner. Even though it is not possible to directly validate elicitation results (as assets are not run to failure) we believe that the process that we have adopted has minimised errors and can be considered fit to use for monetised risk reporting and investment planning. Materiality analysis has been carried out to demonstrate the impact of the assumed asset deterioration rate on monetised risk and investment (Section 5.2.2).

### 7.2.7. Volume of gas lost through leaks

Includes sensitive variables: <Minor Hole Size>

The sensitive input value is the assumed hole size for a minor leak but this the same conclusions apply for the significant leak hole size assumption.

To determine the quantity of the emissions, the leak volume equation from the Pipeline Rules of Thumb Handbook[22], has been used with an assumed hole size of 5mm for significant leaks and 1mm for minor leaks.

Allowing for conversion to imperial units, the following equation has been used to calculate the volumes of gas lost through leaks on AGIs.

$$\textbf{Volume of emissions in } \mathbf{m^3 = 0.00157088 \times D^2 \times P \times T}$$

Where: D is the leak hole diameter in mm; P is the operating pressure (bar); T is the leak run time (hours)

Operating pressures are site specific and apply to all assets within the site boundary.

For significant leaks a hole size of 5mm is assumed. We do not routinely collect leak hole sizes and so this a reasonable assumption based on discussions with internal and external asset experts. Leak run times must also be assumed as, unless the leak is detected via a real-time monitoring system or results in an immediate operational consequence (which is

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[22] E W McAllister 5th Edition ISBN 0-7506-7471-7, 5th Ed, 2002

rare), the start time of the leak is unknown. Assumed leak run times for significant leaks are as follows:

- 10 minutes for Bacton and St Fergus (which are 24 hour attended sites)[23]
- 12 hours for compressor sites
- 24 hours for all other sites

For minor leaks a hole size of 1mm is assumed and longer run times than the above, based on the lower urgency of the leaks and that for unmanned sites these leaks may remain undetected between maintenance visits. Assumed leak run times for minor leaks are as follows:

- 24 hours for Bacton and St Fergus
- 24 hours for compressor sites
- 14 days for all other sites

Until specific data is collected on leak hole sizes and run times these figures are working assumptions. Their impact on monetised risk and investment is explored in Section 5.2.6 and 5.2.77.2.3.

The expert review recommends that leak size should be better recorded along with better characterisation of leaks and that a scaling relationship be applied to account for leak flow rates from different asset types (e.g. pipework and flanges). The data currently does not exist to do this and will be considered as part of future model improvements.

In summary, we believe our calculated leak flow rates provide a reasonable best central estimate but recognise that improvements could be made. There is limited data, either held within NGGT or published in industry documents, to validate our assumptions.

### 7.2.8. Likelihood of gas ignition given a leak

Includes sensitive variables: <P_Delayed_Ignition>; <P_Explosion_Ignition>; <P_Immediate_Ignition>

The logic for fires and explosions probability of consequence is based on several reference sources which have been combined for the purposes of our modelling. The challenge must be to take data that has been collected using very specific site-based or laboratory/academic and to generate generic values which can be used consistently over the entire NGGT asset base. Clearly, simplification and assumptions have been necessary to achieve this. As we have no experience of fire or explosions, and industry data in general is limited, it is not possible to directly validate the consequence likelihood numbers used.

Sources used to inform our analysis include:

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[23] Easington is 24 hour manned but is currently modelled as a 24 hour / 14-day response

- “Review of the event tree structure and ignition probabilities used in HSE’s pipeline risk assessment code” (MISHAP RR1034). Prepared by the Health and Safety Laboratory for the Health and Safety Executive 2015.
- “The User Guide for the AGI safe package V5.1”, DNV GL Report No 13492, 2014
- “Detonation: Should it be Included in Hazard and Risk Assessment?”; V H Y Tam, M D Johnson DNV GL Chemical Engineering Transactions Vol 48 2016
- “Guidelines for Evaluation Process Plant Buildings for External explosions and Fires. Centre for Chemical Process Safety”; AICE 1996. App A Explosion & Fire Phenomenal and Effects

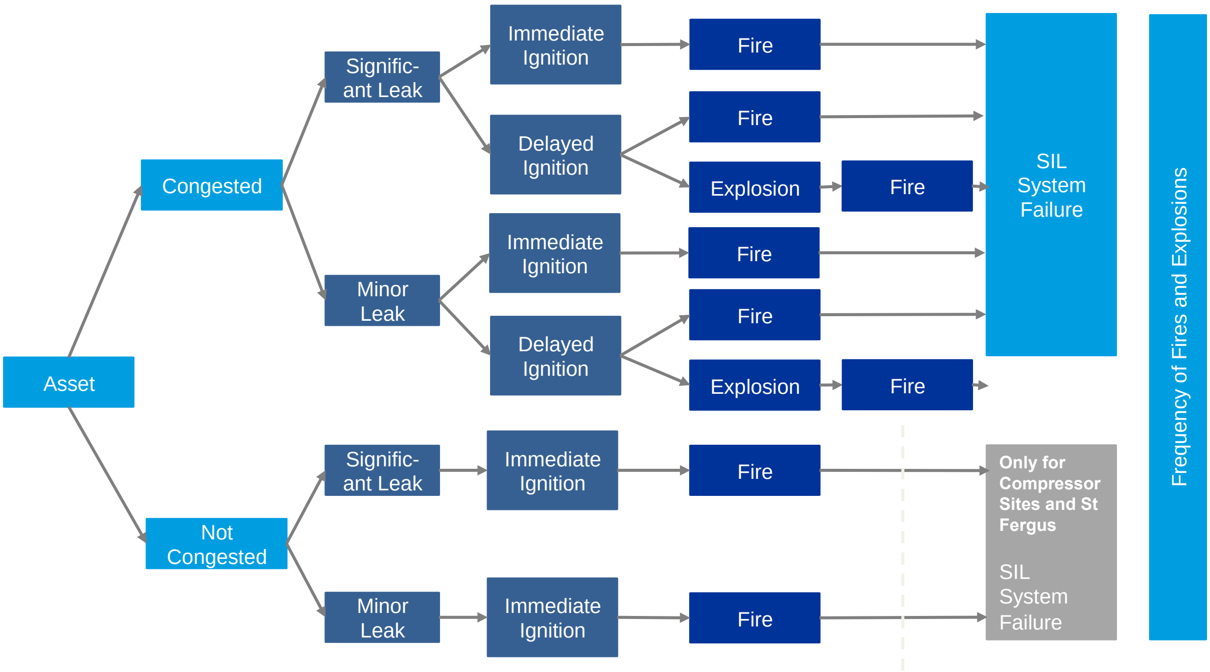

Figure 23 - Logic tree for fires & explosions on sites

Figure 23 summarises how conditions that lead to fire and those that lead to explosion are related in.

The top half of the diagram describes situations where the space in which the natural gas leak occurs is “congested” with equipment/pipework in a confined space. Congested areas provide the conditions under which a flammable vapour cloud could form and if ignited could lead to an explosion. The probability of explosion applies when a major or minor leak occurs, followed by delayed ignition that has allowed a sufficient vapour cloud to form. Following an explosion, it is assumed that a fire will always occur.

The relevant probabilities of immediate and delayed ignition for NGGT assets are provided in the “The User Guide for the AGI safe package V5.1” and summarised in the Fire Safety reports for compressor stations[24]. As previously we assume a 5mm hole size for significant

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[24] Report Number: 10567 Generic Fire Risk Assessment Methodology for Compressor Stations, September 2010

leaks and zero probability of a fire or explosion for minor leaks (which carry Environment risk only).

We assume that there are no significant leaks with a hole size greater than 5mm. This reduces the ignition risk, but leaks of this size are rare.

The HSE MISHAP RR1034 document was used to estimate the probability of explosion following ignition, which is based on analysis undertaken on offshore installations Table 27 shows the probability of a gas explosion given ignition taken from the HSE report:

**Table 27 - Probabilities of explosion given an ignition**

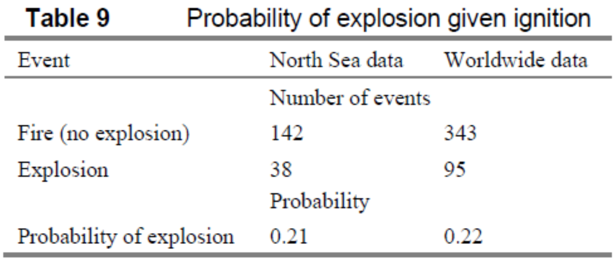

**Table 9** Probability of explosion given ignition

| Event | North Sea data | Worldwide data |
|---|---|---|
| | Number of events | |
| Fire (no explosion) | 142 | 343 |
| Explosion | 38 | 95 |
| | Probability | |
| Probability of explosion | 0.21 | 0.22 |

There are limitations to this assumption in that the MISHAP event tree used by the HSE does not include the probability of a Vapour Cloud Explosion (VCE) as it was developed for locations where the degree of confinement and congestion are minimal. This is being further investigated by HSE following the Buncefield incident.

HSE MISHAP RR1034 refers to a further source[25] for the probability of VCEs. This reference confirms the probability of explosion following a release of flammable gas is dependent upon delayed ignition. It also states that delayed ignition can result in an event demonstrating both flash fire and explosion characteristics, and the fraction modelled as an explosion is equal to 0.4. RR1034 states the occurrences of flash fires in natural gas release events are low due to the buoyancy of the gas.

RR1034 States that VCE’s occur when overpressure is produced because of combustion in the presence of obstacles, structures or partial confinement. RR1034 states the risk associated with VCEs is negligible in areas with low congestion and confinement. In addition, the non-ideal location of the cloud and the lack of a strong ignition source in the medium range inhibits the event.

For the purposes of the Methodology we have ignored the possibility of a VCE, as there are few instances where an asset resides in a congested area, and the probability of explosion given ignition is assumed to be 0.21 based on the RR1034 reference.

In summary, the modelling of ignition risk and the protection (or otherwise) provided at specific locations is complex and we have needed to make assumptions to use available

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[25] RIVM Reference Manual Bevi Risk Assessments Version 3.2 2009

data for a strategic (as opposed to individual site) purpose. We have used industry experts to help us source and interpret the available reference data and tailor it for our generic modelling purposes. The likelihood of an explosion is very low and the major risks are associated with employee loss of life due to fire.

An improvement to the Methodology would be to undertake further detailed modelling of individual sites and assets to determine the level of risk associated with assets near the primary failure event. This is not possible at present as the asset register data feeding the Sites model has no connectivity or geographic referencing making this impossible without site specific surveys, or work to map existing surveys to referenced assets.

Further studies upon the nature and size of leaks observed on site (e.g. flanges; pipework etc.) could improve the characterisation of leak types and hence risk.

### 7.2.9. Properties at risk from fire or explosion

Includes sensitive variables: <HS_FATAL_MID_PROPN>; <HS_FATAL_INNER_PROPN>

The modelling of hazard area surrounding assets is a complex topic which has been studied extensively and incorporated into NGGT hazard assessment procedures[26]. Our challenge has been to apply these principles in a strategic modelling application, where we need to assign a risk to many thousands of assets individually, which has involved interpretation and judgment of available literature. Most available literature focuses on specific sites and asset configurations. Our models currently do not model assets based on their connectivity or spatial proximity to other assets. This may be explored as part of future improvements to the Methodology, such as the use of Reliability, Availability and Maintainability (RAM) modelling for sensitive sites and assets.

Hazard distances were derived from studies undertaken by industry experts[27,28] These distances are then applied using spatial analysis to identify and count the number of properties potentially impacted by a fire or explosion at a specific geographic location. The hazard ranges are quantified as in Figure 24 assuming a full-bore rupture[29].

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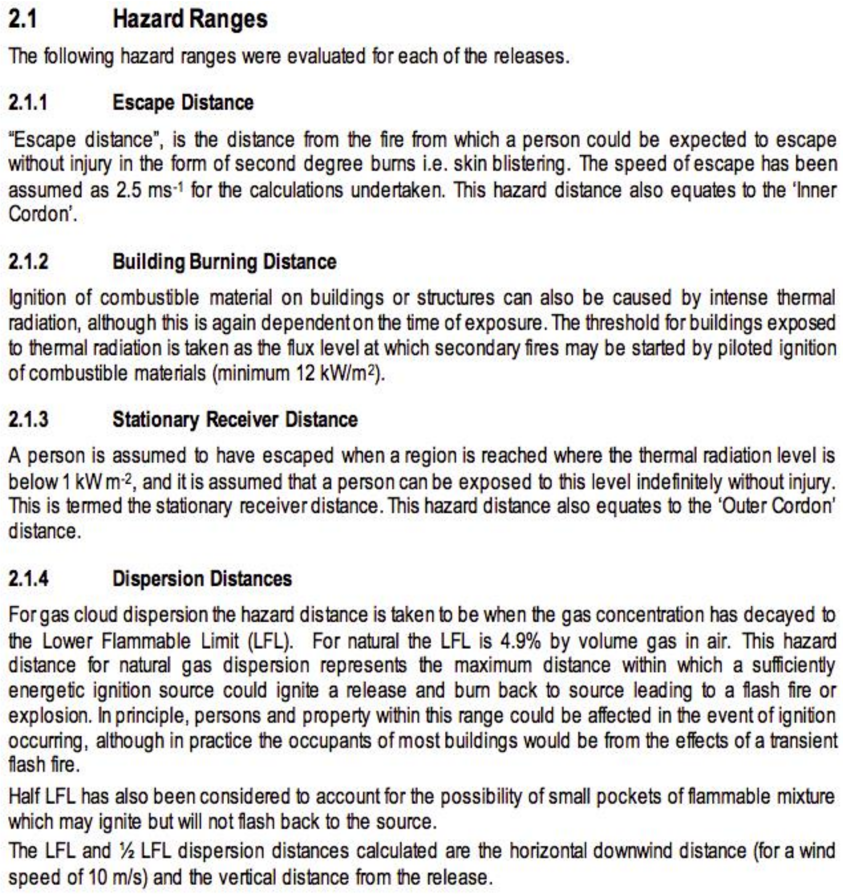
[26] HAZARD ASSESSMENT METHODOLOGY MANUAL FOR ABOVE GROUND INSTALLATIONS, July 2016

[27] Hazard Range Calculations for National Grid Compressor Stations, Report Number: 14373 August 2013

[28] NATIONAL GRID HATS UPDATE Hazard Assessment of the National Grid Transmission System National Grid Report No.: 155218, Rev. 0 Date: September 2016

[29] Hazard Range Calculations for National Grid Compressor Stations, GL Noble Denton, Report Number: 14373 August 2013 p10



### 2.1 Hazard Ranges

The following hazard ranges were evaluated for each of the releases.

#### 2.1.1 Escape Distance

"Escape distance", is the distance from the fire from which a person could be expected to escape without injury in the form of second degree burns i.e. skin blistering. The speed of escape has been assumed as 2.5 ms$^{-1}$ for the calculations undertaken. This hazard distance also equates to the 'Inner Cordon'.

#### 2.1.2 Building Burning Distance

Ignition of combustible material on buildings or structures can also be caused by intense thermal radiation, although this is again dependent on the time of exposure. The threshold for buildings exposed to thermal radiation is taken as the flux level at which secondary fires may be started by piloted ignition of combustible materials (minimum 12 kW/m$^2$).

#### 2.1.3 Stationary Receiver Distance

A person is assumed to have escaped when a region is reached where the thermal radiation level is below 1 kW m$^{-2}$, and it is assumed that a person can be exposed to this level indefinitely without injury. This is termed the stationary receiver distance. This hazard distance also equates to the 'Outer Cordon' distance.

#### 2.1.4 Dispersion Distances

For gas cloud dispersion the hazard distance is taken to be when the gas concentration has decayed to the Lower Flammable Limit (LFL). For natural the LFL is 4.9% by volume gas in air. This hazard distance for natural gas dispersion represents the maximum distance within which a sufficiently energetic ignition source could ignite a release and burn back to source leading to a flash fire or explosion. In principle, persons and property within this range could be affected in the event of ignition occurring, although in practice the occupants of most buildings would be from the effects of a transient flash fire.

Half LFL has also been considered to account for the possibility of small pockets of flammable mixture which may ignite but will not flash back to the source.

The LFL and ½ LFL dispersion distances calculated are the horizontal downwind distance (for a wind speed of 10 m/s) and the vertical distance from the release.

Figure 24 - Hazard range definitions used for estimating safety consequences

Building Planning Distances (BPD) taken from the NGGT Pipeline Data Book. The spatially derived INNER, MIDDLE and OUTER zones are allocated to the BPD's as follows based on conversations with pipeline experts:

- INNER zone = 1 x BPD
- MIDDLE zone = 4 x BPD
- OUTER zone = 8 x BPD

Further discussions with pipelines experts determined a series of assumptions as to the likely proportions of fatalities and injuries within each zone. As there is no definitive source of information to allow fatality/injury rates to be applied generically, these assumptions remain subjective. As per the recommendations of the expert review specific QRA assessments potentially could be used for sites/locations with known high safety risk, but there has been insufficient time to implement this recommendation and existing QRA reports cannot be easily applied to our Methodology (e.g. different definitions of an asset).

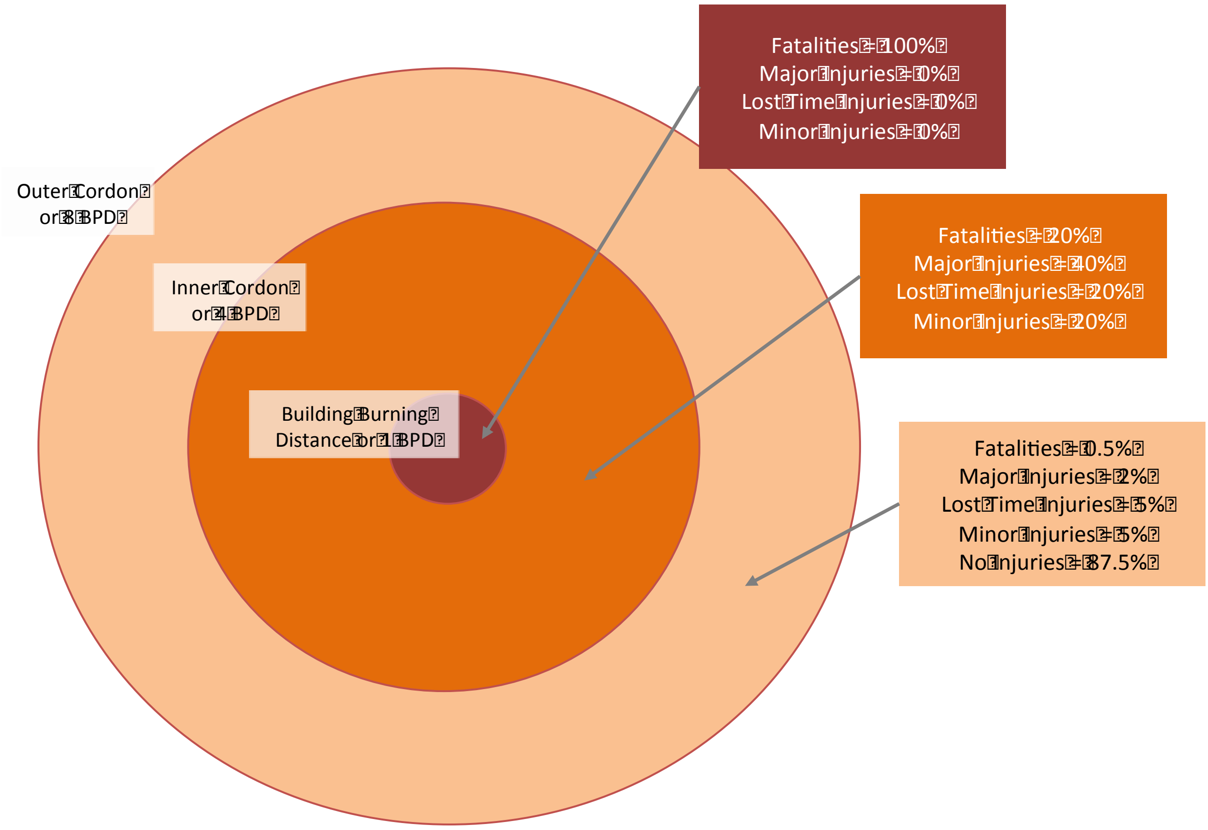


Figure 25 - Applied hazard ranges and fatality/injury rate assumptions

Number of properties have been estimated using available mapping data. A simple intersection between the hazard zones and the OS VectorMap was carried out. Estimation of the number of properties affected was carried out by assuming all buildings are domestic and two stories in height. The following equation was used to determine the number of properties affected:

**Properties Affected = Area of building intersect / (Average floor area / Average number of stories)**

The average floor area of a domestic property in the UK is assumed to be 96 square metres and two stories in height. It is recognised this is a simplistic assumption and will be improved once NGGT have access to specific property location details (through OS MasterMap), which will also allow domestic and industrial/commercial properties to be treated separately.

### 7.2.10. Rural and Suburban correction factor

Includes sensitive variables: <Rural Locations>

The expert review highlighted that there was a potential for over-statement of population risk from fires and explosions. The previous approach was believed to overstate Safety risk as:

- The BPD values used to define the hazard zones are generally specified for rural and not suburban areas

- Compliance with the pipeline standard IGEM/TD/1 requires that any properties inside 1 BPD are subject to mitigation to minimise the consequence in event of fire or explosion.

The reviewers recommended that correction factors to be applied based on degree of likely protection at these locations which were applied in our models. The application of these factors reduces the numbers of fatalities by a factor of 90% in rural areas and 97% in Suburban areas. For the Sites model we have assumed all assets are in rural areas, whereas for Pipelines we have used localised property density to assign a rural/urban flag. We recognise this is a simplified assumption which can only be resolved using site/location specific QRA studies.

### 7.2.11. People at risk of death or injury

Includes sensitive variables: <People per Property>; <HS_FATAL_MID_PROPN>

As per the Service Risk Framework supporting document[30], the number of members of the public resident in a property at the time a fire or explosion consequence occurs is highly sensitive in the calculation of Safety service risk. The Office of National Statistics (ONS) recommends an average occupancy of 2.3 for domestic properties. Clearly a property will not be occupied for 24 hours per day, 365 days per year. Standard QRA generally uses an assumption of 2 persons per property in residence at the time of the incident. As this is such a sensitive element of the model we have taken a bottom-up approach to estimate average occupancy over a 24-hour period. As such an average 24-hour occupancy rate of **1.63** has been estimated based on the assumptions contained in Table 28 below.

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[30] **Section 4.6**

**Table 28 – Estimation of average property occupancy and data sources**

| | | |
|---|---|---|
| UK Population | 65600000 | https://www.ons.gov.uk/peoplepopulationandcommunity/populationandmigration/populationestimates/articles/overviewoftheukpopulation/july2017 |
| Children | 17.70% | https://www.ons.gov.uk/peoplepopulationandcommunity/populationandmigration/populationestimates/articles/overviewoftheukpopulation/july2017 |
| 16 to 64 (Assumed Working) | 57.70% | https://www.ons.gov.uk/peoplepopulationandcommunity/populationandmigration/populationestimates/articles/overviewoftheukpopulation/july2017 |
| Aged 65 and over (Assumed retired) | 24.70% | https://www.ons.gov.uk/peoplepopulationandcommunity/populationandmigration/populationestimates/articles/overviewoftheukpopulation/july2017 |
| | | |
| Unemployment Rate | 4.30% | https://www.ons.gov.uk/employmentandlabourmarket/peoplenotinwork/unemployment |
| Unemployed | 1627601.6 | UK Population x 16 to 64 (Assumed Working) x Unemployment Rate |
| Time in house during week (unemployed) | 100 | 20 hours x 5 days |
| Time in house during weekend (unemployed) | 32 | 16 hours x 2 days |
| Percentage of Time in House (unemployed) | 78% | (Time in house per week (unemployed) - Holidays per week) / Hours per week |
| **Number of Unemployed in House** | **1276612.74** | Unemployed x Percentage of Time in House (unemployed) |
| | | |
| Children and Aged 16 to 64 who are employed | 47834798.4 | (UK Population x Children) + (UK Population x 16 to 64 (Assumed Working)) *(1-Unemployment Rate) |
| Time in House during week (employed) | 75 | 15 hours x 5 days |

| | | |
|---|---|---|
| Time in house during weekend (employed) | 32 | 16 hours x 2 days |
| Percentage of Time in House (employed) | 64% | (Time in house per week (employed) - Holidays per week) / Hours per week |
| **Number of Children and aged 16 to 64 who are employed in house** | **30401051.30** | Children and Aged 16 to 64 who are employed x Percentage of Time in House (employed) |
| | | |
| Retired | 16203200 | UK Population Aged 65 and over (Assumed retired) |
| Time in house during week (retired) | 100 | 20 hours x 5 days |
| Time in house during weekend (retired) | 32 | 16 hours x 2 days |
| Percentage of Time in House (retired) | 78% | Time in house per week (retired) - Holidays per week / Hours per week |
| **Number of Retired in House** | **12709014.05** | Retired x Percentage of Time in House (retired) |
| | | |
| Average Number of Holidays Abroad (nr per year) | 1.70 | https://abta.com/assets/uploads/general/Holiday_Habits_Report_2017.pdf |
| Average Number of Holidays Abroad (days / year) | 11.90 | Average Number of Holidays Abroad * 7 days |
| Number of Holidays per week | 0.23 | Average Number of Holidays Abroad (days / year) / 52 weeks |
| | | |
| Total Number of Households | 27227700 | https://www.ons.gov.uk/peoplepopulationandcommunity/birthsdeathsandmarriages/families/adhocs/005374totalnumberofhouseholdsbyregionandcountryoftheuk1996to2015 |
| | | |
| **Number of People Per Property** | **1.63** | (Number of Unemployed in House + Number of Children and aged 16 to 64 who are employed in house + Number of Retired in House) / Total Number of Households |

Industrial and commercial property occupancy has not been specifically assessed. However, the method used to estimate properties at risk currently uses the footprint of an average property surrogate for property counts. As commercial properties tend to have larger footprints they will be counted as >1 property with an associated higher population at risk. Although not ideal, this counteracts the potential understatement of Safety risk at industrial/commercial sites. Alternative mapping sources to better separate domestic and industrial/commercial populations will be explored through revisions to the Methodology

Estimation of numbers of employees on site in the event of a fire or explosion has been estimated using historic work volumes and typical job times. For the Sites model, this is the major contributor towards Safety risk as employees are at risk of both fires and explosions. A simplistic approach has been used to estimate the daily average numbers of employees on site at the time of a fire/explosion event. The method currently takes no account of non-operational staff based on the site (i.e. working in site offices/buildings.

**Annual number of working hours on site / Annual available number of working hours**

Where the annual number of working hours is specific to each NTS site, taken from actual work details recorded on our Ellipse asset register. The available number of working hours assumes 5 hours working on assets per day (excluding travelling and breaks).

### 7.2.12. Value of a loss of life or major injury

Includes sensitive variables: <Gross Disproportion Factor>

As per the Service Risk framework supporting document[31], NGGT can reasonably choose not to carry forward investment where health and safety investment would be grossly disproportionate to the benefits. This is applied in the form of a Gross Disproportionality Factor (GDF), which is applied as multiplier to the societal Safety valuations.

As HSE do not provide any specific guidance as to the appropriate GDF to use, we have chosen a value in line with the Gas Distribution and Electricity Transmission networks.

We have applied a common GDF value of ten for both public and employees in our current modelling. HSE guidance indicates that the GDF for employees, who knowingly put themselves at risk, could be lower than for the public who cannot control their exposure to risk. Based on our internal QRA document[32], a GDF of two (2) could potentially be used for employees, but this is not implemented presently.

We do not propose changing the assumption of a GDF of ten for both public and employees at this stage. It should be noted that most the persons at risk within the Sites model are NGGT employees as explosion events are very rare and the Safety consequence of fires is constrained to the site boundary and a lower GDF may potentially be more appropriate, but based on the modelled numbers of fires/explosions Safety risk is already low. Further

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[31] Section 4.5

[32] National Grid Quantified Risk Assessment (QRA) document (T/SP/G/36)

discussions with the HSE may be required to agree the most appropriate use of the GDF in monetised risk calculations.

## 7.3. PIPELINES

### 7.3.1. Sensitive input variables

As per Section 4.4, the sensitive input variables for Pipelines are as follows. Defects rates and defects deterioration are included as although assumed to be error-free they drive all monetised risk calculations.

- Defect rates
- Defect deterioration assumptions
- Cathodic protection deterioration
    - <Det CIPS>
- Alternating Current (AC) induced corrosion growth rates
    - <Elec_Transmission_Factor>
- Rate of corrosion defect growth under different levels of protection
    - <Det Corrosion High>
    - <Det Corrosion Med>
- Volume of gas lost through leaks and ruptures
    - <Block Valve Distance> which includes
        - Leak Hole Size
        - Leak Run Time
- People at risk of death of injury
    - <People per Property>
    - <HS_FATAL_MID_PROPN>
- Value of a loss of life or major injury
    - <Gross Disproportion Factor>

### 7.3.2. Defect rates

#### Base data

Data is generated by linking several NGGT systems together, with UPTIME GIS providing the master data set. A girth weld (12 metre pipe section) is defined to be the base unit of measurement and attribution as it can be considered a near constant homogenous unit of both probability of failure and consequence of failure.

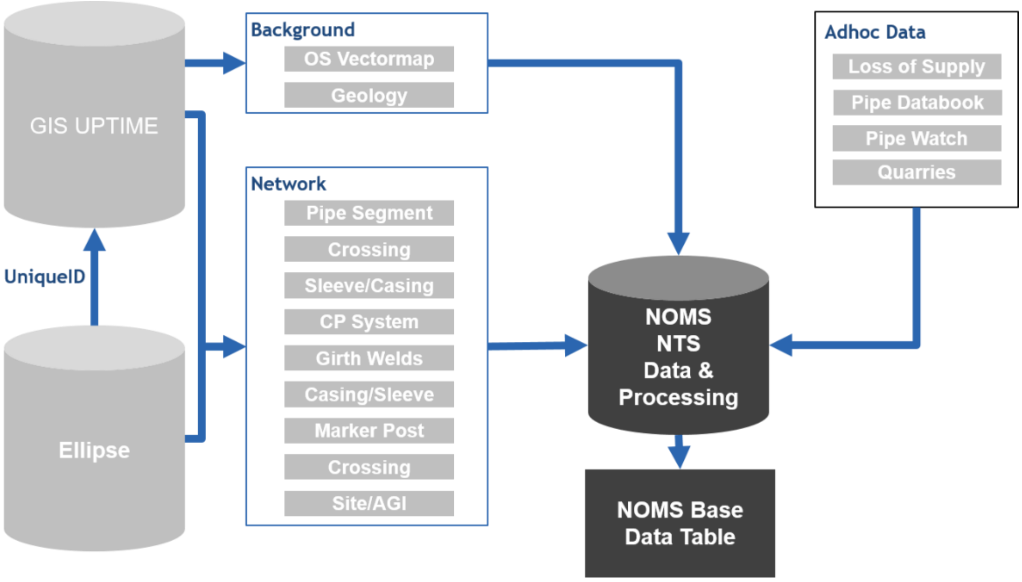

Figure 26 – Pipelines data source overview

## Benchmarking & Scaling

An analysis of the UKOPA data set was undertaken to provide some benchmarking of key failure modes. UKOPA data is used to benchmark and scale each of the key failure risk fault nodes and the number of leaks. EGIG data used to benchmark and scale the number ruptures due to very low UKOPA sample size. This benchmarking and scaling was revalidated through the expert review and checked against a sample of specific pipelines sections.

It should be noted as there are very few historic failures on the NTS network it is not possible to assign an absolute level of risk. The current levels of failure, and hence monetised risk valuation, is a benchmarked value based on our current integrity management philosophy and investment in intervention and remediation activities. This approach is supported by the expert review. The resulting baseline level failure frequencies are shown in Table 29.

Table 29 - Summary of modelled NTS failure frequencies post benchmarking and scaling

| Measure | Failure Rate |
|---|---|
| Ruptures | 1 in 17 years (all through third party damage) |
| Leaks | 1 in 3 years |
| Fatalities | 1 every 6 years[33] |
| Pressure reductions | 5 per year |

UKOPA fault data collection started in 1962 and is a collection of all fault data on UK LTS and NTS pipeline networks[34].

The UKOPA data does not contain sufficient information to undertake the same exercise for rupture probabilities. EGIG data[35] was used to compare the leak probabilities derived using UKOPA data and derive probabilities of defects becoming ruptures. As before, these are then normalised and multiplied by the network lengths as shown in Table 30.

Table 30 - EGIG derived leak and rupture rates (benchmark input data)

| Failure Mode | Benchmark (nr/km/yr) | | |
|---|---|---|---|
| | Leak | Rupture | Total |
| Corrosion | 5.46E-05 | 4.20E-07 | 5.50E-05 |
| Mechanical (Material Construction) | 5.15E-05 | 3.53E-06 | 5.50E-05 |
| General (other) | 3.66E-05 | 4.18E-07 | 3.70E-05 |
| Interference | 1.26E-04 | 3.04E-05 | 1.56E-04 |
| Ground Movement | 1.52E-05 | 1.08E-05 | 2.60E-05 |
| **Total** | 2.84E-04 | 4.56E-05 | 3.29E-04 |

We have multiplied the EGIG leak failure rates by the network length to give the expected annual failures. The total leaks arising from all failure modes is given as 5.5 per year compared to 5.3 per year using UKOPA data, which shows the two industry data sets are comparable.

The EGIG benchmarked rupture frequency for UKT is 0.35 per year (1 in 3 years) which is high, due to high assumed interference and ground movement frequencies in the EGIG data set. The EGIG leak rates are also high due to higher corrosion and material frequency failure rate assumptions.

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[33] This is an annualised fatality risk. This is equivalent to 16 people every 100 years which could be due to a single event.

[34] UKOPA Pipeline Product Loss Incidents and Faults Report (1962-2013)

[35] EGIG – Gas pipelines incidents, 9th Report of the European gas pipeline Incident Data Group (period 1970-2013)

The raw UKOPA and EGIG benchmark frequencies were used to calculate consequence probability values which best represent the current integrity risk on the NTS. This was carried out by dividing the expected value of leaks by the measured number of faults that could generate a leak or rupture. These consequence probability values for leak and rupture are shown in Table 31 and Table 32.

**Table 31 - Leak consequence probability values benchmarked against UKOPA**

| **Node** | **Description** | **Calculated as NTS leaks/NTS faults** |
|---|---|---|
| P_Leak_Corrosion | Probability of a leak given corrosion[36] | 100% |
| P_Leak_Mechancial | Probability of a leak given mechanical defect (material & construction) | 1.16% |
| P_Leak_General | Probability of a leak given general failure | 6.98% |
| P_Leak_Interference | Probability of leak given external interference | 1.42% |
| P_Leak_Natural | Probability of a leak given natural event | 0% |

**Table 32 - Rupture consequence probability values benchmarked against UKOPA**

| **Node** | **Description** | **Calculated as NTS leaks/NTS faults** |
|---|---|---|
| P_Rupture_General | Probability of rupture given general failure | 0% |
| P_Rupture_Interference | Probability of rupture given external interference | 2.43% |
| P_Rupture_Mechancial | Probability of a rupture given mechanical defect (material & construction) | 0% |
| P_Rupture_Natural | Probability of a rupture given natural event | 4.76% |
| P_Rupture_Corrosion | Probability of a rupture given corrosion | 0% |

It should be noted that some of these PoC values are different to those quoted in the Consequence of Failure supporting document (Section 2.2) and will be corrected in future revisions to the NOMs Methodology. These changes were made following the expert review.

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[36] A value of 100% is used due to our leak modelling process. Once sufficient wall thickness loss has occurred then a gas leak is assumed to have occurred. Therefore, the probability of a leak given a corrosion failure is 1 (Probability of Failure supporting document, Section 4.3)

### 7.3.3. Corrosion defect numbers

All raw corrosion (metal loss) defects are recorded as part of the ILI runs and assigned to individual pipe segments across the network. It should be noted that only a proportion of these raw defects are severe enough to drive increased pipeline inspection frequencies (modelled through Intervals2)[37]. These defects are then grown over time into corrosion faults (major) using the wall thickness loss model.

The number of defects per pipe is calculated firstly by the latest recorded ILI measurements. However, due to the small pipe segment lengths, there are many pipes with zero defects and we would expect the number of defects to grow in future time periods as well – due to ground movement, weather conditions, or other unknown and random events.

The number of defects per length is calculated using NGGT specific data, with a linear model is fitted using average age per feeder as the predictor variable which gives the following predictive equation ().

**Corrosion detects per metre = 0.000158 x Pipeline Age + 0.002**

For the whole NTS, this corresponds 1000 new defects appearing every year (1.7%). As this is based on historic ILI data we have good confidence in this assumption. Pipeline age is used as a surrogate for pipeline condition to distribute the appearance of new defects in the model, although other factor such as the protection offered by CP could be considered. Alternating Current (AC) induced corrosion growth rates

Includes sensitive variables: <Elec_Transmission_Factor>

An uplift of 20% to the corrosion growth rate was assumed if corrosion defects exist on pipelines within 50 metres of an overhead AC source based on discussions with pipeline experts. Research to better quantify this effect is ongoing. The expert review that a higher rate of 1.1 mm/year could be adopted, but this gave very high leak failure rates and we have agreed not to incorporate this assumption pending further research. The sensitivity of this assumption is discussed in Section 5.3.6.

### 7.3.4. Rate of corrosion defect growth under different levels of protection

Includes sensitive variables: <Det CIPS>, <Det Corrosion High>, <Det Corrosion Med>

Our corrosion model takes account of the reduction in the rate of metal loss when a pipeline is effectively protected using cathodic protection (CP). CP performance is measured during routine pipeline surveys and the protection afforded is recorded as a value in millivolts (mV). This value is used to determine the amount of corrosion protection (resistance) offered by the CP system (Table 33)[38].

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[37] http://www.ukopa.co.uk/wp-content/uploads/2013/03/UKOPA-13-028.pdf

[38] Intervals2

**Table 33 - CP health indicators linked to pipeline corrosion resistance**

| Resistance to corrosion | CIPS Pipe to Soil Potential |
|---|---|
| Very high, negligible corrosion rate | < -950 mV |
| High resistance (average resistance in anaerobic soil) | -950 to -850 mV |
| Average resistance | -850 to -550 mV |
| Low resistance | ≥ -550 mv |

To test the applicability of corrosion resistance (or its inverse, the corrosion growth rate[39]) values (as shown in Table 34), actual fault data and assessed corrosion defect growth rates was taken from the UKOPA data set and a probability distribution of corrosion growth (reduction in wall thickness) fitted to a Weibull distribution for each assessed band of pipeline corrosion growth (High, Medium, or Low). Figure 27 shows that by comparing these fitted Weibull curves to observed corrosion growth rates from the UKOPA data-set, a reasonable fit can be observed. In reality, the UKOPA data set will be a mixture of low, medium and high corrosion rates.

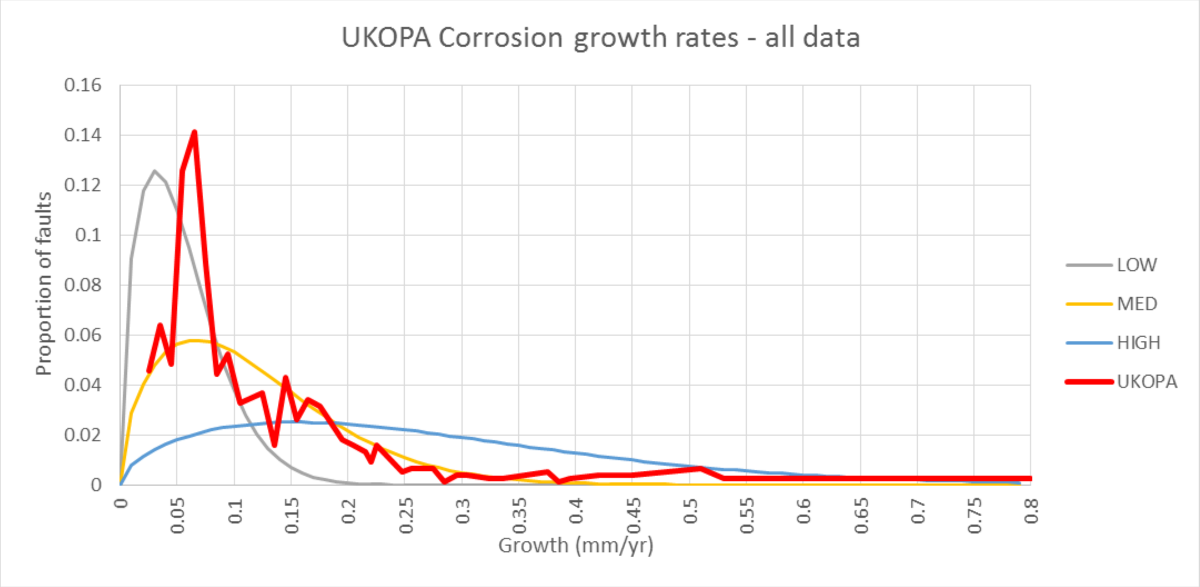

**Figure 27 -** Modelled corrosion growth rates. Legend is corrosion rate, not corrosion resistance

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[39] A high corrosion resistance implies a low corrosion rate, and vice versa

**Table 34 – Corrosion resistance rate from Intervals2. High corrosion resistance equates to low defect growth rate**

| **Corrosion resistance** | **Corrosion Rate Expected Value (mm/year)** |
|---|---|
| High (<Det Corrosion Low>) | 0.05 |
| Medium (<Det Corrosion Med>) | 0.12 |
| Low (<Det Corrosion High>) | 0.27 |

The applied corrosion resistance banding is applied based on actual measurements of CP performance (through CIPS surveys). The corrosion defect growth rate associated with the applied banding is used to calculate the remaining wall thickness, which reduces at a rate in proportion to the defect growth. The likelihood of a leak (loss of integrity) is then predicted using this calculated wall thickness value. The relationship between the remaining wall thickness and the leak consequence probability was estimated through conversations with pipeline integrity engineers.

Figure 28 shows that the probability of a leak from a corrosion defect only exceeds 0.1 after 80% of the pipe wall has corroded away. We investigate corrosion defects when 20% of wall loss has been identified through ILI, so very few corrosion defects should reach this 80% position with effective CP system maintenance.

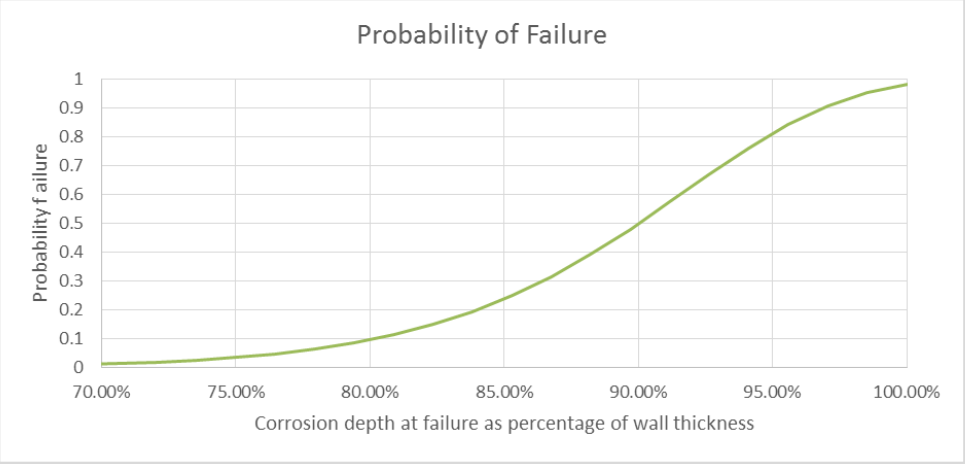


**Figure 28 – Probability of a corrosion failure based on percentage remaining wall thickness**

### 7.3.5. Cathodic system protection deterioration

Includes sensitive variables: <Det CIPS>

The rate of deterioration of the corrosion protection provided by CP system is modelled based on extrapolation between the protection offered by a new CP system and one at its assumed end of life.

CIPS deterioration was based on assuming an expected life of 30 years for the CP system, an average of 15 for the sacrificial anode and 25 for the transformer rectifier. Corrosion protection for a new CP system and at end of life is based on the values presented in Table 35.

**Table 35 - CP health indicators linked to pipeline corrosion resistance (Intervals2)**

| Resistance to corrosion | CIPS Pipe to Soil Potential |
|---|---|
| Very high, negligible corrosion rate | < -950 mV |
| High resistance (average resistance in anaerobic soil) | -950 to -850 mV |
| Average resistance | -850 to -550 mV |
| Low resistance | ≥ -550 mv |

A linear model was fitted through these soil potential values to give an initial 23mV per year CP protection deterioration rate assumption.

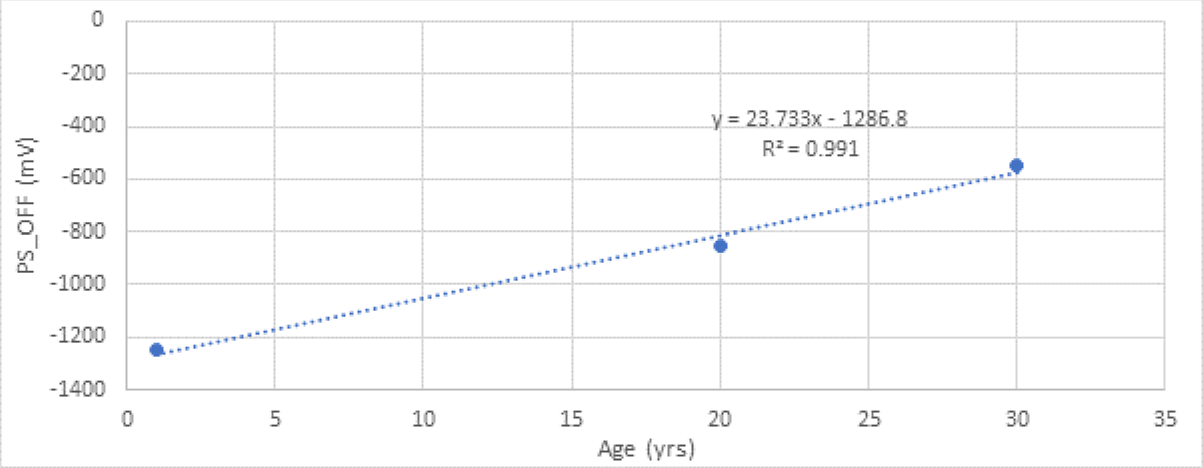


**Figure 29 - CP system protection deterioration based on an assumed 30-year life**

When this 23 mV/year deterioration rate was used to predict the numbers of major corrosion defects requiring investigation it was found to significantly overstate the numbers of major defects (defined as a corrosion defect with >20% wall thickness loss). A value of 9 mV/year was shown to give the expected rate of major corrosion defect investigations of around 44 per year.

It is likely that CP system deterioration is not linear, but more likely to a Weibull distribution with accelerated deterioration as the CP system reaches the end of its asset life. As this assumption is sensitive (Section 5.3.4) further research will be carried out and will inform future improvements to the Methodology.

### 7.3.6. Volume of gas lost through leaks

Includes sensitive variables: <Block Valve Distance> which includes Leak Hole Size and Leak Run Time

## Calculation overview

For the sensitivity analysis, three parameters were modelled together as they represent the assumptions required to estimate the total volume of gas lost through a fixed orifice size

- Run time – length of time gas is lost from the network at a fixed rate
- Hole size – determines the rate of gas loss through a fixed orifice. For rupture this is the pipeline diameter
- Block valve distance – the length of the network that needs to be depressurised and vented to undertake a repair. This is effectively the distance between block valve stations.

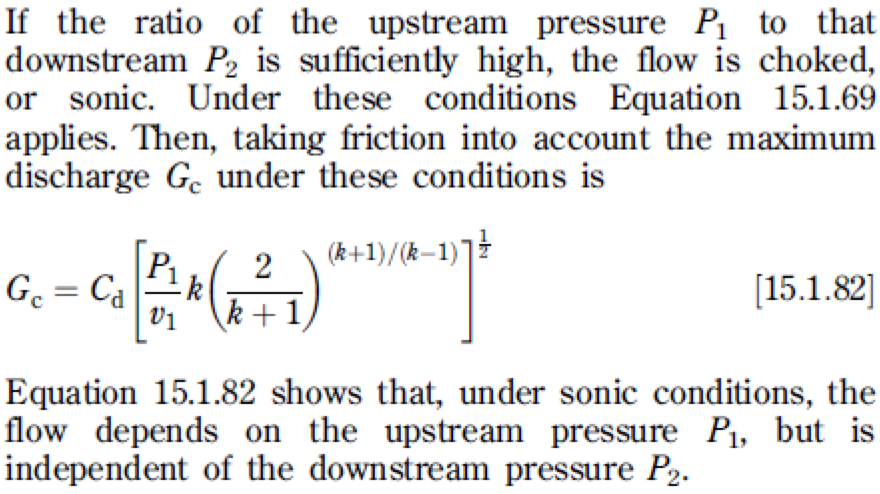
As rupture frequency and the resulting loss of gas is much lower than leak frequency and gas loss, only the leak flow rate assumption is discussed. However, equivalent conclusions can be drawn as the calculations are similar.

The rate of gas loss is also highly sensitive to pipeline operating pressure and pipeline diameter, but these are known values taken from our Pipeline Data Book and assumed to be error-free.

The following equation has been used to calculate the total loss of gas from a leak is calculated in two stages. First the gas lost in undertaking the repair is estimated using the volume of gas stored in the pipe section to be isolated.

**Gas lost in repairing leak = π x Block Valve Distance x Operating Pressure x (Pipeline Diameter/2)$^2$**

The relationship between the leak hole size and discharge rate is modelled by standard discharge rate equations.



If the ratio of the upstream pressure $P_1$ to that downstream $P_2$ is sufficiently high, the flow is choked, or sonic. Under these conditions Equation 15.1.69 applies. Then, taking friction into account the maximum discharge $G_c$ under these conditions is

$$G_c = C_d \left[ \frac{P_1}{v_1} k \left( \frac{2}{k+1} \right)^{(k+1)/(k-1)} \right]^{\frac{1}{2}} \qquad [15.1.82]$$

Equation 15.1.82 shows that, under sonic conditions, the flow depends on the upstream pressure $P_1$, but is independent of the downstream pressure $P_2$.

Except for Operating Pressure (P) and Leak Hole Size ($C_d$ is the area of the hole) all other elements of this equation are constants. Therefore, for a fixed hole size a linear relationship between gas discharge rate and operating pressure can be established (Figure 30).

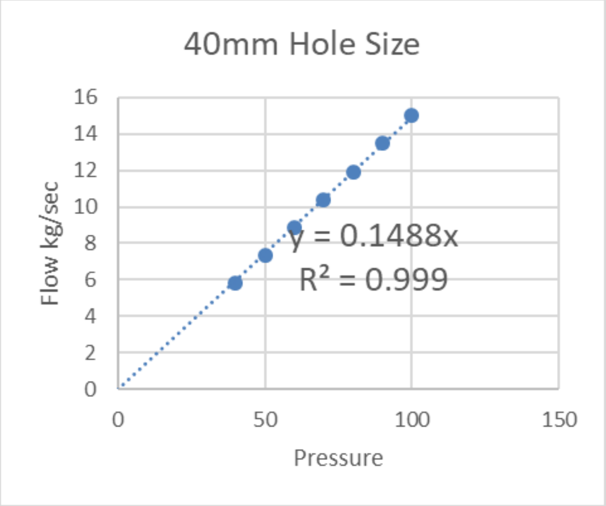


Figure 30 – Relationship between gas pressure and discharge rate for a 40mm leak

This then allows the volume of gas lost before the leak can be isolated to be calculated by multiplying the discharge rate by the leak run time.

**Gas lost while leak is running through a 40 mm leak = 0.1488 x Operating Pressure x Leak Run Time**

And the total loss of gas from the leak can then be estimated:

**Total gas volume lost from leak = Gas lost in repairing leak + Gas lost while leak is running through a 40 mm leak**

## Leak hole size

As there have been no corrosion leaks from the NTS since data was collected we have had to assume an average hole size. The following definitions of a leak hole size were taken from IGEM/TD2[40]:

- Pin hole - Equivalent hole diameter up to 6 mm
- Small hole - Equivalent hole diameter greater than 6 mm and up to 40mm
- Large hole - Equivalent hole diameter greater than 40 mm but less than pipe diameter
- Rupture - Equivalent hole diameter equal to or greater than pipe diameter

TD/2 also states that "*In deriving pipeline failure frequencies induced by specific damage mechanisms for use in pipeline risk assessment, account needs to be taken of pipeline specific factors such as wall thickness, pressure, diameter, material properties, location, environment and pipeline operator management practices*".

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[40] Section A4.1

Based on the above a Leak Hole Size of 40mm was selected as the upper range of a Small hole (as per TD/2 definitions) given that the NTS operated at higher pressures than LTS. Should a smaller hole size be selected a different relationship between discharge rate and operating pressure is formed.

The relationship between assumed leak hole size and monetised risk is sensitive (Section 5.3.3). Future improvements to the Methodology should consider a likely distribution of corrosion hole sizes to define the expected which may potentially be larger or smaller than 40mm, but data does not currently exist to do this for the NTS. Table 5 of the UKOPA report[41] shows that 34 out of 192 corrosion faults measured since 1962 have been with hole sizes of 20mm or higher, which indicates our assumption is conservative but reasonable. However, these will have been collected over differing operating pressures and pipeline integrity standards. The expert review did not specifically comment on the corrosion hole size assumption, but it was not challenged.

### Leak Run Time

A leak run time of 12 hours was assumed, corresponding to:

- The time for NGGT to become aware of the leak
- The time to depressurise and isolate for repair

This is equivalent to the assumption for significant leaks on compressor sites, based on the larger hole size and the likelihood that a 40mm leak will be reported by the public.

### Block Valve Distance

It is not currently possible to work out the true pipeline length between block valves from the Pipelines model because block valves are modelled within our Sites model. A value of 13,000 metres (13km) was applied which corresponds to the total pipeline length divided by the number of AGIs. A limitation of this approach is that the volume of gas lost from a leak on a pipeline section with the same operating pressure will be identical, however on average the total leak volumes will be consistent.

A method to more accurately calculate the distance between block valve stations will be explored through improvements to the NOMs Methodology (see Section 10.2.2, Action 2.2).

## 7.3.7. People at risk of death or injury

Includes sensitive variables: <People per Property>; <HS_FATAL_MID_PROPN>

The treatment of numbers of persons at risk of death of injury from pipeline asset failure is identical to Sites (Section 7.2.9), except that no NGGT employees are at risk of death or injury from pipeline asset failure. Safety risk tends to be higher as the pipeline network covers a more extensive geographic area and passes through areas of higher population density.

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[41] UKOPA: Pipeline Product Loss Incidents and Faults Report (UKOPA/15/003)

The suburban/rural factor (Section 7.2.10) was not deemed sensitive for Pipelines. However, a correction factor of 0.03 is applied if the pipeline passes through urban/suburban areas and a value of 0.1 is applied in rural areas. This flag is set based on the density of properties within the defined hazard zones, calculated using spatial data analysis and applied to individual 12-metre pipe sections.

### 7.3.8. Value of a loss of life or major injury

Includes sensitive variables: <Gross Disproportion Factor>

The derivation of the Gross Disproportionality Factor (GDF) is identical as for Sites (Section 7.2.12). However, as only the public are judged to be at risk from pipeline failures then a GDF of ten (10) is appropriate in all cases.

## 7.4. GAS EMISSIONS VALIDATION

A top-down check was undertaken to ensure that all unburned gas emitted from the NTS was accounted for across Sites and Pipelines models (shrinkage). It was not possible to directly compare shrinkage assumption on individual models as the data is not captured consistently (e.g. block valves are part of the pipeline for emissions reporting, but are included within our Sites model).

The concept of Maintenance Emissions was introduced to account for non-failure related shrinkage. These are defined as related to routine maintenance activity, not condition-related failures. The maintenance emissions are calculated from the difference between overall emissions and emissions from gas leaks and ESD vents and split between all gas emitting failure modes.

By allocating the unburned gas emissions to maintenance emissions, the models now fully represents Environment risk. Failure-related emissions only contribute 6% of overall emissions in the base year, but this proportion will increase for without intervention scenarios. As most of our proactive maintenance activities occur at AGIs, all maintenance emissions were allocated to the Sites model.

Maintenance emissions have the same environmental private and social costs as emissions from leaks and ESD vents and are subject to the same condition-based annual maintenance uplift as baseline repair and maintenance costs. This is to represent increased maintenance requirements as assets age.

# 8. LTS / NTS PIPELINES BENCHMARKING

## 8.1. APPROACH

A core element of the expert review was comparison of the inputs and outputs from our models with UK and international benchmarks. These benchmarks have been used to set an appropriate level of monetised risk for the pipeline network based on current levels of integrity management (Section 7.3.2), These comparisons need to be undertaken carefully as:

- Non-UK networks often have different regulatory mechanism and operational challenges
- Data is not collected consistently (e.g. leak volumes)

This section describes some specific benchmarking we have carried out with the Gas Distribution Networks (GDNs) using outputs from their NOMs Methodology. Similar challenges exist as for non-UK networks, in that operational challenges and data collection may not be consistent so we have limited this comparison to NTS and Local Transmission System (LTS) pipelines only. It may be theoretically possible to compare our Exit points with GDN Offtakes, as they contain similar assets, but we model data at different levels of detail (asset versus) making comparisons difficult without more in-depth analysis.

Individual GDN figures have been anonymised within this report.

## 8.2. COMPARISON OF MONETISED RISK

A comparison of normalised (per kilometre) monetised risk was done, split down by common elements of the SRF.  Availability and Social Risk have been combined to correspond with the GDN Customer risk measure.

The NGGT costs include all fixed costs of maintaining the network Without direct knowledge of how the GDNs have calculated their monetised risk values it is difficult to draw conclusions as to reasons for any differences but the following general observation and conclusions can be made.

### 8.2.1. Total Monetised Risk

Overall levels of monetised risk appear to be low compared to the LTS networks. The most obvious comparison is a more rural network, which would appear to be consistent with the geographically disperse nature of the NTS. Intuitively, one might expect overall NTS risk to be higher than LTS so this merits further investigation. Our lower monetised risk overall is possibly explained by proactive intervention costs not being included within total monetised risk (e.g. rectification of corrosion defects following ILI surveys).

### 8.2.2. Customer Risk

In our modelling this generally corresponds to Availability risk. The NGGT per-kilometre Customer risk is nearly 10 times lower than the least risky LTS network and 130 times lower than the riskiest network. Our expected rate of outages resulting from the pipeline network is 1 in 17 years. We would expect the numbers of properties impacted to be greater for an NTS asset than an LTS asset, so we can only assume that the LTS outage rate is significantly higher for GDNs than assumed for the NTS. Customer compensation per-household costs are taken from GDN sources and are assumed to be equivalent.

### 8.2.3. Health & Safety Risk

NTS Safety risk is significantly lower than all LTS networks. Safety risk is predominantly related to proximity of populations to assets and the proportional relationship with rurality would be expected given no bias in the input data assumptions. The Safety risk reduced significantly when we applied the correction factors which limited the risk of loss of life or injury due to fire or explosion. We do not know if the GDNs have applied similar correction factors within their analysis.

### 8.2.4. Carbon Risk

Carbon risk for NGGT is much greater than for all LTS networks and will be related to an assumed number of leaks and ruptures arising from external interference and corrosion. This is most likely due to higher operating pressures and longer pipeline sections that may need to be vented in the event of failure. As no network reports a significant number of corrosion leaks, we understand that all baseline risk is calibrated to a pooled UKOPA data set of historic failures. Therefore, it would seem likely that differences in the operational characteristics of the NTS and LTS would explain the greater Carbon risk on the NTS.

### 8.2.5. Financial Risk

Financial risk largely corresponds to the daily running of the network, including proactive maintenance to manage risk and achieve Pressure Systems Regulation (PSR) compliance (e.g. cathodic protection systems; marker posts; ILI runs; surveillance etc.).

NGGT Financial risk appears to be relatively low. It might be expected that the size and complexity of the NTS, with the associated operational challenges of managing an extensive geographic area may have resulted in a higher unit Financial risk, although there may be some economies of scale. However, costs of investigating and remediating corrosion defects are not included in the NGGT baseline Financial risk, as we consider these to be proactive interventions. It is possible the GDNs include these ILI digs in their baseline costs.

Without understanding the costs feeding into this risk for the LTS networks it is not possible to comment further.

# 9. MONETISATION OF AVAILABILITY & RELIABILITY RISK

## 9.1. OVERVIEW

As described in the Main Methodology document[43] we have adopted a simplistic approach to estimate Availability and Reliability (AR) risk. A MS Excel connectivity-based model has been developed, using NTS experts to correlate the relationship between individual pipeline and AGI outage and upstream and downstream risk. This approach is summarised in the Consequence of Failure supporting document[44]. The valuations used to monetise these asset risks are discussed in the Service Risk framework supporting document[45].

Two major issues were identified by the expert review (Section 6.2.1):

- That the Safety risk associated with the wide-scale loss of supply to customers is not included
- That the social costs (potential increase in customer gas prices) caused by breakdown of the UK gas trading market (and we are unable to transport gas from major Entry points) are not modelled

The Safety risk issue was initially valued but not included after discussions with Ofgem, as the potential number of fatalities is large but the likelihood of such an event occurring is small it is difficult to quantify the risk with confidence. The impact on the gas trading market was not considered and should be explored through a future improvement to the Methodology.

The expert review also recommended:

- That alternatives to the single year flow scenarios should be explored, including the 1 in 20 peak demand scenarios
- That compressor risk should be valued in a consistent method with that used for our 10-year statement
- That the model should be simplified to remove assets (e.g. block valves) which carry very little chance of generating an AR risk
- That the model should be adapted to model partial site outage where this is a possibility (e.g. regulator streams)
- That the connectivity model used potentially contains errors and should be revisited

Following this review, and discussions with Ofgem, further work to test and improve the AR risk modelling approach was undertaken.

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[43] Section 3.2, Potential Supply and Demand Impacts

[44] Section 6 and Appendix C

[45] Section 6 and Appendix E

## 9.2. SCOPE OF MODEL IMPROVEMENT WORK

Following the expert review and discussions with Ofgem, several updates have been made to the AR model which have changed the valuations of AR and monetised risk predicted through the Methodology.

### 9.2.1. Supply & demand scenario

Several scenarios and the potential impact of each of these on the AR monetised risk analysis were discussed with Ofgem. These included:

1. A 1 in 20-year scenario using current demands as the base year
2. A Bacton Terminal Stressed scenario, where demands are stressed locally to reflect Bacton operating at full capacity and demands for the remainder of the network rebalanced to a level corresponding to the highest winter day demand experienced over the last 7 years
3. A St Fergus Terminal Stressed scenario, where demands are stressed locally to reflect St Fergus operating at full capacity and demands for the remainder of the network rebalanced to a level corresponding to the highest winter day demand experienced over the last 7 years
4. An Easington Terminal Stressed scenario, where demands are stressed locally to reflect Easington operating at full capacity and demands for the remainder of the network rebalanced to a level corresponding to the highest winter day demand experienced over the last 7 years
5. A Milford Haven Terminal Stressed scenario, where demands are stressed locally to reflect Milford Haven operating at full capacity and demands for the remainder of the network rebalanced to a level corresponding to the highest winter day demand experienced over the last 7 years
6. A low-summer’s day demand scenario, with high gas flows into storage

A comparison of AR risk resulting from each of these scenarios, using the original fixed Entry constraint cost assumption, is discussed in Section 9.3. Entry flows for the modelled scenarios are summarised in Table 36:

| **Supply Type** | **Bacton Stressed** | **St Fergus Stressed** | **Milford Haven Stressed** | **Easington Stressed** | **1 in 20** | **Summer** |
|---|---|---|---|---|---|---|
| Bacton Terminal | 93 | 28 | 38 | 38 | 38 | 27 |
| Bacton Interconnector | 50 | 45 | 45 | 45 | 89 | 10 |
| Barrow Terminal | 4 | 4 | 4 | 4 | 4 | 3 |
| Easington Terminal | 43 | 64 | 54 | 84 | 67 | 35 |
| Burton Point Terminal | 2 | 2 | 2 | 2 | 1 | 2 |
| St. Fergus Terminal | 55 | 117 | 52 | 67 | 88 | 56 |
| Teesside Terminal | 21 | 21 | 21 | 21 | 21 | 15 |
| Theddlethorpe Terminal | 4 | 4 | 4 | 4 | 4 | 3 |
| Milford Haven Terminal | 23 | 30 | 75 | 30 | 72 | 15 |
| Isle of Grain Terminal | 21 | 1 | 21 | 21 | 13 | 0 |
| LNG Storage | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Storage | 63 | 63 | 63 | 63 | 103 | 0 |
| Shale | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Sources | 0 | 0 | 0 | 0 | 0 | 0 |
| **TOTAL (mcm/d)** | **378** | **378** | **378** | **378** | **500** | **165** |

**Table 36 – Entry flows used for fixed capacity buyback comparison under alternative supply and demand scenarios**

Following this initial analysis, it was agreed that for initial use of the NOMs Methodology that a 1-in-20 scenario should be used. From a range of possible scenarios, it was proposed that a 1-in-20 demand scenario, from gas year 2021 (running from October 2020 to October 2021), would be most appropriate. This scenario covers the final winter of the T1 period, thus giving the best representation of the end of this price control. To project forward in time we have used the Future Energy Scenario (FES)[46] Steady Progression scenario. Steady Progression is consistently used within NGGT as it is the most conservative scenario with regards to the rate of decarbonisation and decentralisation and provides a conservative, but realistic indication of what levels of NTS demand may be experienced in the future.

A comparison between the final 1-in-20 scenario and alternative scenarios, using a new variable Entry constraint cost assumption, is discussed in Section 9.4.

### 9.2.2. Variable Entry and Exit constraint costs

Following internal discussions, we have adopted a new approach to model the potential costs of Entry (terminal) and Exit (offtake) constraints. Previously a fixed capacity buyback assumption was used, whereby the constraint cost was independent of the flow at the terminal at the time of the outage. The constraint cost is now modelled to be directly proportional to the assessed terminal flow, or customer demand, under the chosen supply and demand scenario. Terminal flows and customer demands under each scenario are now taken from our hydraulic modelling solution (SIMONE).

### 9.2.3. Removal of flow swap capability

By using the 1 in 20-year scenario, it is unlikely that the Gas Distribution Networks would be able to accept the request to use alternative offtakes should there be an unplanned outage at an Exit point. Therefore, we have removed all capability to “flow-swap” within our AR risk modelling. The impact of this is that the full risk resulting from the loss of a specific Exit point is now modelled, whereby it was previously factored down should a flow-swap capability exist. This generally has the impact of increasing AR risk.

### 9.2.4. Correction to customer compensation charge for outages

The compensation charge has been updated to £30 per property per day[47] from £20 per property per day. This reflects the current amount payable for a loss of service, which has increased since the original risk valuation was undertaken[48]. This monetised risk is modelled as a societal cost, as these charges are payable by the gas supplier, not NGGT.

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[46] http://fes.nationalgrid.com/fes-document/

[47] https://www.citizensadvice.org.uk/consumer/energy/energy-supply/problems-with-your-energy-supply/get-compensation-if-you-have-a-power-cut/

[48] Planning and Network Analysis Requirements for the Evaluation of Security of Supply (T/PM/NP/15)

### 9.2.5. Entry and Exit constraint values

The Auction Book Prices for Entry points has been updated to the Quarterly System Entry Capacity (QSEC) Reserve and Step Prices[49].

The Auction Book Prices for Exit points have been updated to the Indicative prices for 2020/21[50]. these can be found in: Notice of Final NTS Exit (Flat) Capacity Charges effective from 1 October 2019, and Indicative NTS Exit (Flat) Capacity Charges for the 2019 Annual Application Window for Enduring Annual NTS Exit (Flat) Capacity dated the 30th April.

We propose that these Auction Book Prices are reviewed annually and any significant changes to overall monetised risk resulting from a change in Entry/Exit constraint cost valuations addressed through a material change process.

## 9.3. FIXED CAPACITY BUYBACK SCENARIO COMPARISON

To test the sensitivity of different supply and demand (SD) scenarios on AR and overall monetised risk, six new scenarios were developed (as per Section 9.2.1) and compared with the original SD scenario, based on an average, high winter's day NTS flows. The original scenario was constructed using historic flow data taken from NGGT telemetry/SCADA systems. To model a range of alternative scenarios, where there may not be a historic record of flow data to construct the desired scenario, requires a different approach.

A range of SD scenarios were modelled using our SIMONE gas transmission hydraulic analysis tool. From these hydraulic model scenarios, the following data was extracted for use in our AR modelling tools.

- Terminal (Entry) flows
- Exit demands, split by customer type
- Pipeline flows
- Pipeline flows were then used to model the flows through Above Ground Installations (AGIs), including Compressor stations

Pipeline and AGI flows are used to model the Value of Flow component of AR risk, which estimates the capacity loss associated with an outage of every NTS asset.

Entry and Exit flows are used to estimate the constraint compensation cost associated with the inability to transport gas from shippers to suppliers. For this initial analysis, a fixed capacity buyback value is used, which is the same regardless of the modelled Entry/Exit flows. This assumption is changed to a variable Entry/Exit flow assumption for the next stage of sensitivity analysis (Section 9.4).

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[49] Notice of Revised NTS Entry Capacity QSEC Reserve and Step Prices (17th January 2019) (https://www.nationalgridgas.com/document/125136/download)

[50] Notice of Final NTS Exit (Flat) Capacity Charges effective from 1 October 2019, and Indicative NTS Exit (Flat) Capacity Charges for the 2019 Annual Application Window for Enduring Annual NTS Exit (Flat) Capacity (30th April 2019) (https://www.nationalgridgas.com/document/126946/download)

### 9.3.1. Comparing total Availability & Reliability monetised risk

Table 37 shows the differences in the overall levels of AR monetised risk using different SD scenarios. These are the AR risk values assuming an asset has failed and **exclude** the probability of an outage occurring. The percentage values are the difference between the defined scenario and the original and Bacton Stressed scenarios respectively.

| **Scenario** | **Compared to Original Total AR Risk Difference** | **Compared to Bacton Stressed Total AR Risk Difference** |
|---|---|---|
| **Bacton Stressed** | 39% | 0% |
| **St Fergus Stressed** | 40% | 1% |
| **Milford Haven Stressed** | 39% | 0% |
| **Easington Stressed** | 39% | 0% |
| **1 in 20** | 40% | 1% |
| **Summer** | 39% | 0% |

Table 37 – Comparison of AR monetised risk between alternative supply and demand scenarios (fixed capacity buyback assumption)

The comparison shows a relatively large difference between the Original and other scenarios. This is due to differences in how risk values are allocated to pipelines and AGIs using the new hydraulic modelling derived flows, including the reallocation of risk between the St Fergus Terminal, multijunction and associated pipeline feeders. However, differences between scenarios using the same hydraulic model sourced risk values are minor. This is mainly due to the assumption of a fixed capacity buyback value, which means the analysis is insensitive to changing flows at Entry and Exit points

### 9.3.2. Comparing Availability & Reliability CoF risk values

Table 38 shows the differences in the AR consequence of failure (CoF) values using different SD scenarios. These **include** the probability of an outage resulting from an asset failure and relate to the true, current level of AR risk for the NTS.

| **Scenario** | **Compared to Original AR CoF Difference** | **Compared to Bacton Stressed AR CoF Difference** |
|---|---|---|
| **Bacton Stressed** | 15% | 0% |
| **St Fergus Stressed** | 18% | 3% |
| **Milford Haven Stressed** | 14% | -1% |
| **Easington Stressed** | 15% | 0% |
| **1 in 20** | 18% | 3% |
| **Summer** | 14% | -1% |

Table 38 - Comparison of AR consequence of failure between alternative supply and demand scenarios (fixed capacity buyback assumption)

When comparing to the original scenario, differences in AR CoF risk are lower than for AR monetised risk, but the differences are still significant. The AR CoF risk differences, when compared to the Bacton Stressed scenario are still small, but greater than seen with the total

AR monetised risk comparison. This is because Entry points have a higher volume of modelled outages as there are more assets per site and more failure modes types that could cause potentially generate an outage consequence.

The St Fergus and 1 in 20 scenarios shows the biggest difference when compared to Bacton. A higher flow out of St Fergus (when stressed) combines with a high modelled outage potential to generate a 3% overall increase in AR CoF risk (NTS demands are equivalent for these scenarios). The 3% increase for the 1 in 20 scenario, when compared to Bacton, is due to higher overall NTS demands (and hence higher flows through AGIs and pipeline assets).

### 9.3.3. Summary of AR risk using fixed capacity buyback assumption

In summary, using a fixed capacity buyback assumption for Entry and Exit points results in minimal sensitivity of the AR risk to the applied SD scenario, assuming a consistent method to model flows is used. The migration from telemetry/SCADA based flows to the use of flows derived from hydraulic modelling has:

- Allowed multiple SD scenarios to be tested and compared, which is not possible just using historical flow data
- Generated a step-change in AR risk due to better modelling of flows, both at Entry/Exit points and within the network

## 9.4. VARIABLE CAPACITY BUYBACK SCENARIO COMPARISON

Following agreement of a final SD scenario, and other model updates (Section 9.2.1), a further comparison was carried out between the following scenarios:

1. A 1 in 20-year scenario using FES Steady Progression and 2021 base demands (agreed as our scenario for T1 rebasing)
2. A 1 in 20-year scenario using FES Steady Progression and 2025 base demands (to test the sensitivity to change of the FES demand base year)
3. A Bacton Terminal Stressed scenario (to show differences between a fixed and variable capacity buyback assumption)

Entry flows for the modelled scenarios are summarised in Table 39:

| **Terminal** | **Bacton Stressed** | **1 in 20 2021 FES** | **1 in 20 2025 FES** |
|---|---|---|---|
| Bacton Terminal | 93 | 31 | 19 |
| Bacton Interconnector | 50 | 79 | 96 |
| Barrow Terminal | 4 | 4 | 2 |
| Easington Terminal | 43 | 76 | 61 |
| Burton Point Terminal | 2 | 1 | 0 |
| St. Fergus Terminal | 55 | 85 | 82 |
| Teesside Terminal | 21 | 39 | 28 |
| Theddlethorpe Terminal | 4 | 0 | 0 |
| Milford Haven Terminal | 23 | 54 | 67 |
| Isle of Grain Terminal | 21 | 1 | 1 |

| | | | |
|---|---|---|---|
| LNG Storage | 0 | 0 | 0 |
| Other Storage | 63 | 102 | 111 |
| Shale | 0 | 0 | 5 |
| Other Sources | 0 | 0 | 0 |
| **TOTAL** | **378** | **472** | **472** |

**Table 39 - Entry flows used for variable capacity buyback comparison under alternative supply and demand scenarios**

The original scenario, using telemetry/SCADA flows and a fixed capacity buyback assumption, was also retained for comparison.

Rather than the fixed capacity buyback assumption used previously, capacity buyback (constraint) costs are now variable based on the proportional change in Entry and Exit flows. This means that when modelled flows increase the constraint cost will be higher, reflecting the higher value of the Entry or Exit point under each SD scenario. As the actual constraint costs resulting from outages or to prevent an outage are highly complex, this is acknowledged to be a simplified approach. Improving these valuations would require direct integration with trading models (which simulate how the energy market would respond to NTS restrictions and inform how we may influence the market to avoid or mitigate outages).

### 9.4.1. Comparing total Availability & Reliability monetised risk

Table 40 shows the differences in the overall levels of AR monetised risk using alternative SD scenarios. These are the AR risk values assuming an asset has failed and **exclude** the probability of an outage occurring. The percentage values are the difference between the defined scenario and the Original and Bacton Stressed scenarios respectively.

| **Scenario** | **Compared to Original Total AR Risk Difference** | **Compared to Bacton Stressed Total AR Risk Difference** |
|---|---|---|
| Bacton Stressed | 47% | 0% |
| 1 in 20 2021 FES | 78% | 21% |
| 1 in 20 2025 FES | 80% | 22% |

**Table 40 - Comparison of AR monetised risk between alternative supply and demand scenarios (variable capacity buyback assumption)**

The comparison shows a relatively large difference between the Original and other scenarios. This is due to differences in how risk values are allocated to pipelines and AGIs using the new hydraulic modelling derived flows, including the reallocation of risk between the St Fergus Terminal, multijunction and associated pipeline feeders. The increase of the compensation payment from £20 to £30 and the removal of the flow-swap assumption have also contributed to the increase from the original scenario.

Use of a 1 in 20 SD scenario increases AR monetised risk by around 20%, when compared to a stressed terminal SD scenario (Bacton in this case). There is minimal difference between the adoption of a 2021 or 2025 base year for demands.

### 9.4.2. Comparing Availability & Reliability CoF risk values

Table 41 shows the differences in the AR consequence of failure (CoF) values using alternative SD scenarios. CoF vales **include** the probability of an outage resulting from an asset failure and relate to the true, current level of AR risk for the NTS.

| **Scenario** | **Compared to Original**<br>**AR CoF Difference** | **Compared to Bacton Stressed**<br>**AR CoF Difference** |
|---|---|---|
| Bacton Stressed | 106% | 0% |
| 1 in 20 2021 FES | 146% | 19% |
| 1 in 20 2025 FES | 147% | 20% |

**Table 41 - Comparison of AR consequence of failure between alternative supply and demand scenarios (variable capacity buyback assumption)**

Comparison of AR CoF risk values show a similar trend as observed for total AR risk. The difference between the original and other scenarios is greater for AR CoF than for total AR risk because of increased weighting towards the terminals, based on their higher modelled outage frequency.

### 9.4.3. Summary of AR risk using variable capacity buyback assumption

In summary, using a variable capacity buyback assumption for Entry and Exit points, using terminal and pipeline/AGI flows derived from hydraulic modelling and updated service risk valuations has:

- A 150% increase in AR CoF risk (total AR monetised risk has increased by around 80%), when compared to the original scenario (which uses a fixed capacity buyback assumption)
- A 20% increase in AR CoF risk using 1 in 20 demand scenarios, when compared to a stressed terminal demand scenario (Bacton in this case). Both scenarios in this comparison are based upon variable capacity buyback assumptions

The additional validation work undertaken has allowed us to model the sensitivity of the AR analysis under a range of SD scenarios and improve the overall valuation of AR risk.

However, the valuation of AR risk is still under-stated until the adopted AR risk method can fully:

- Take account of the safety impact of wide-scale loss of supply, including the risk of fatalities due to hypothermia and attempted self-connections
- Account for the economic impact on the UK gas trading market

We also recognise that the AR risk modelling approach needs to be made more dynamic, to explore the likelihood of different SD scenarios occurring through a probabilistic approach. This is a major undertaking which will be addressed through ongoing updates to the Methodology (see Section 10.1.2, Action 1.1).

## 9.5. FOLLOW-ON EXPERT REVIEW

A further expert review session was arranged to validate the improvements made to the AR risk modelling approach. The conclusions are summarised below:

*The changes made by NGG to the loss of supply consequence model used by the AIM model improves the way in which the AIM model assess the risk associated with loss of supply. The updates address recommendations 6, 7 and 8 of the report; however, they do not address recommendation 10 which required further work to quantify the impact a major loss of supply event would have on the general public and industry.*

*In order. to ensure the AIM model continues to assess the risk associated with loss of supply effectively the following inputs should be reviewed and updated annually:*

*a) Review and update the supply consequence model using the most appropriate 1 in 20 winter scenario from the current Gas Ten Year Statement and materiality assessment*

*b) Ensure the domestic compensation and connection charges are updated following any change.*

*c) Update the Entry and Exit capacity charges in line with the most recent auction prices.*

Any potential changes to service valuations identified through annual reviews will be incorporated subject to materiality criteria to be agreed with Ofgem.

# 10. SUMMARY & IMPROVEMENT PLAN

We have undertaken extensive validation on the Sites and Pipelines models that allows total monetised risk (TMR) and proactive investment costs to be produced using the NOMs Methodology.

Our approach does not monetise the existing Asset Heath and Criticality bands. Risk is calculated from first principles using the prevailing asset defect rates as an input to the model. A consequence of this is that observed and measured defects cannot be used to test the outputs from the model. We have focused on the justification of the sensitive inputs to the model and have highlighted where these inputs have a material impact on monetised risk and future investment levels.

In summary, we are confident that the Sites and Pipelines are fully suitable for modelling the **relative** levels of monetised risk for use in monetised risk reporting and investment planning, if the same assumptions for without- and with- intervention analysis are used. An example of this is asset deterioration, where a higher/lower rate of deterioration will result in higher/lower values of intervention benefit.

In terms of modelling **absolute** levels of risk there is greater uncertainty at present, as assumptions need to be made for some sensitive input variables where there is immaturity in modelling monetised risk or limited historical failure and consequence data. This is particularly true for Pipelines where, due to a lack of historic failures. risk has been scaled to an expected level of risk based on industry benchmarks. Comparison with GDN transmission monetised risk values shows that there are no gross errors, but overall risk may be understated

Environment risk appears to be relatively high when compared to Availability or Safety risk. Availability risk is currently biased towards risk at Exit points and further work to consider the wider impacts of wide-scale loss of supply would be beneficial. Availability risk is missing key elements that may increase the overall risk levels to a level expected by stakeholders, such as potential fatality risk and the impact on the ability to transport gas from exit points gas on the UK gas trading market. Environmental risk is high due to the use of HM Government carbon inflation assumptions. It is possible that this imbalance may potentially direct future investment towards assets which do not meet customer’s needs for a safe and reliable network. Fortunately, investments that deliver Environment risk improvements also deliver Safety risk reductions as a secondary benefit. This will be tested through development of the RIIO-T2 Asset Heath investment plans.

A summary of the current risk profile for NTS Sites and Pipelines is presented below, along with a draft improvement plan to address some of the input data uncertainties and limitations identified. Some elements of this plan should be undertaken collaboratively within UK gas pipelines sector and should incorporate international best practice.

## 10.1. SITES IMPROVEMENT PLAN

### 10.1.1. Risk overview

In terms of the Sites model, we have used best available information to determine the current level of monetised risk and how this may change over time due to deterioration. We have tested the model against the few number of consequences that have a large enough sample size to undertake a comparison between model outputs and observed, namely:

- Numbers of Emergency Shutdown (ESD) vents - Section 7.2.3
- Numbers of gas leaks - Section 7.2.4

In early years of the planning period, risk is dominated by Financial risk, the costs of maintaining the network. In later years of the planning period Environment risk dominates, due to the increased rates of gas leakage and through inflation in the social value of carbon. Key sensitive factors driving future monetised risk are therefore:

- Asset deterioration rates
- Compressor unplanned outages (ESD vent numbers and volumes)
- Gas leak numbers and volumes

Safety risk from Sites assets is currently low and does not drive significant investment (Section 7.2.9). It is possible that Safety risk is undervalued at certain locations due to the application of generic assumptions in terms of asset proximity and connectivity.

Availability risk is also low due to the amount of system resilience and the ability to mitigate outages through commercial mechanisms. However, Availability risk is not currently fully quantified in the Methodology, so again will be understated (See Section 9).

### 10.1.2. Improvement plan

Table 42 shows the potential improvement plan for the Sites model and indicative implementation timescales (to be agreed with internal stakeholder and Ofgem). Material changes arising from any improvement actions could potentially trigger a change to the Methodology (threshold to be agreed with Ofgem)

Table 42 – Sites model improvement plan

| Ref | Action | Potential Approach | Timescales |
|---|---|---|---|
| 1.1 | Develop a full risk based approach to quantity Availability risk, that enables alternative supply/demand scenarios to be modelled and the expected values chosen based on risk | Innovation project to bring together strategic planning, reliability and hydraulic modelling tools together into a single environment allowing the likelihood and consequences of asset failure to be explored under different prevailing conditions (current and future) and NTS operating scenarios.<br>The **strategic planning models** will determine how often a specific supply/demand will occur, allowing the profile of scenarios to be generated<br>The **reliability models** will predict how often a failure consequence and account for asset connectivity and resilience (this may be done at a site level for major entry/exit points)<br>The **hydraulic models** will quantify the consequence of asset failure and account for NTS resilience and interconnectivity<br>These tools generally already exist but are not linked together<br>A project plan will be developed pending completion of the ongoing RIIO-T2 compressor strategy analysis and a common approach adopted, where possible | 2 -3 years |
| 1.2 | Review the unit of an asset used for modelling asset risk and monetised risk reporting. This is the lowest level of asset risk that can be reported | The current level of modelling, at individual asset equipment level, is challenging as performance and costs data are often not collected at this level with NGGT.<br>A unit of an asset relating to actual, practical asset interventions may be | 1 -2 years |

| Ref | Action | Potential Approach | Timescales |
|---|---|---|---|
| | | more appropriate, but requires changes to our Ellipse system to implement<br>This is the opportunity to remove assets that contribute little to monetised risk from the analysis (e.g. small electricals)<br>The unit of an asset should also be reviewed with GDNs to allow simpler benchmarking of model outputs. | |
| 1.3 | Review and benchmark of asset deterioration assumptions | In safety-critical industries assets cannot be allowed to deteriorate to the point that they fail and generate consequences. Our current deterioration of assumptions is an improvement on those used for T1 as they have used a structured elicitation approach and involved a wider range of business experts.<br>However, future investment levels to manage this risk are sensitive to deterioration assumptions. Two potential improvements will be explored:<br>• Review whether our current elicitation process could be improved, and repeat if necessary<br>• Undertake wider benchmarking, UK and world-wide. This is dependent on having a consistent asset unit between benchmarking companies | 1 year |
| 1.4 | Undertake regular reviews against actual asset failures | ESD vent numbers and volumes can be calculated annually and compared to our assumptions. It may also be possible to apply site-specific vent volumes.<br>Leak numbers can be updated annually and compared with predictive model outputs. Over time, this may allow calibration of asset-type specific failure mode proportions (the proportion of defects that lead to a specific failure mode) | 6 months |

| Ref | Action | Potential Approach | Timescales |
|---|---|---|---|
| 1.5 | Review failure mode assignments and consequence frequencies | The mappings of specific failure modes to assets as carried out using industry experts. Some of these were questioned through the expert review and further validation will be carried out.<br>Failure mode proportions assigned to specific consequences are based on OREDA data, which is predominantly related to offshore industries. An innovation project will be promoted that could potentially collect better data for the onshore gas industry | 1 – 2 years |
| 1.6 | Improve quantification of leak sizes. Currently assumed to be 1mm for a minor leak and 5mm for a significant leak. | A wider benchmarking review will be carried out and (if possible) a profile of leak sizes determined.<br>It is possible that data capture throughout the industry makes this impossible to achieve and that further innovation research may be required to map asset specific failure modes to leak sizes. | 1 – 3 years |
| 1.7 | Use of site-specific Qualitative Risk Assessments (QRA) to inform site-specific safety assessments (population at risk) | Current Safety risk in the model is based on generic assumptions.<br>The use of existing safety QRA reports will be explored for sensitive sites. If the data cannot be used directly in the Methodology an approach to undertake useful site-specific risk assessments will be developed.<br>Implementation of any site-specific QRA is subject to development of the revised approach.<br>This may require development of site-specific models to allow asset connectivity and proximity to be modelled, which is not possible at present.<br>This will also validate the current assumptions of the proportions of population killed or injured within each hazard zone. | Method: 1 – 2 years<br>Implementation: 3 - 5 years potentially |

| Ref | Action | Potential Approach | Timescales |
|---|---|---|---|
| | | Trial on a single high consequence site initially to prove method. | |
| 1.8 | Improve assessment of properties at risk within hazard zones | A suitable mapping source was not available for use in the initial development of the Methodology and properties at risk is inferred using property boundary areas.<br>Purchase of the OS Mastermap spatial data by NGGT will allow property counts within hazard zones to be better quantified | 1 year |
| 1.9 | Include the impact of a wide-scale loss of a gas supply on Safety risk within our Availability/Reliability analysis | This has already been implemented, but the monetised risk values are not included in our current Methodology.<br>Requires further discussions with Ofgem | 6 months |
| 1.10 | Include the impact of a breakdown of the gas trading market (Societal impact) within our Availability/Reliability analysis | This would require a literature search to identify work already undertaken in this area. If suitable analysis does not exist a specialist study may need to be commissioned.<br>This is wider issue than just monetised risk and NOMs Methodology and an industry innovation project may be required | 2 -3 years |
| 1.11 | Update Health and Safety modelling to take account of pressure systems failures on sites | Pressure systems failures to be added as a potential failure mode to relevant assets<br>Frequency and consequences (proportions of deaths and injuries) to be estimated from best available sources | 1-2 years |
| 1.12 | Investigate the possibility of more detailed benchmarking with companies that operate similar transmission networks, across Europe and world-wide. | Identify commonalties that can be realistically benchmarked and undertake detailed comparisons, understanding reasons for differences.<br>Include any identified improvements within future action plans | 2-4 years |
| 1.13 | Implement better, site-specific estimates of failure emissions | Use available information on pipe lengths, fitting/flange numbers etc. to | 2-3 years |

| Ref | Action | Potential Approach | Timescales |
|---|---|---|---|
| | | develop a site-specific emissions estimate, which can then be disaggregated down to specific assets and failure models | |

## 10.2. PIPELINES IMPROVEMENT PLAN

### 10.2.1. Risk overview

The Pipelines model has been built using several industry-standard assumptions, including factors influencing the rate of defect appearance and deterioration. As there have been very few actual failures on the NTS, benchmarking and scaling has been carried out to set a current level of risk in line with the integrity management policy that is in place within NGGT (Section 7.3.2).

The alternative to benchmarking and scaling is that the Pipelines model would have zero condition-related risk in the current year (risk based on potential asset damage only). Therefore, the Pipelines model cannot be confirmed to reporting the true level of absolute risk, but the change in risk levels over time (relative risk) is reasonable as it is based on sound industry assumptions.

The model is sensitive to the factors influencing the rate of pipeline corrosion, such as:

- Corrosion defect growth rates – Section 7.3.4
- Cathodic protection (CP) system deterioration – Section 7.3.5

The CP system deterioration value was calibrated to match the observed rate of appearance of major corrosion defects, which provide confidence in the predictive ability of the model.

The model is also sensitive to factors influencing leak flow rates and subsequent Environment risk, namely:

- Leak hole size – Section 7.3.6
- Response time to isolate leaks – Section 7.3.6

Environment risk is particularly sensitive as once the protection provided by the CP system breaks down under a no intervention scenario, corrosion defects start to grow rapidly and pipeline integrity is lost. We have used guidance from pipelines experts to assign current expected values to these input, based on the limited UK and international experience of resolving corrosion leaks on transmission pipelines, but further collaborative research would be valuable. A further sensitive factor, the distance between block valves, requires additional data to be captured within our asset data systems.

The breakdown of pipeline integrity also causes high Availability risk in later years of the planning period. The same connectivity based model as used for Sites is used and could be improved using a full risk-based approach and hydraulic analysis.

Safety risk is largely driven by the proximity of population to high pressure pipelines, namely

- Hazard zone areas – Section 7.2.9 and 7.3.7
- Proportion of people killed or injured resulting from fire or explosions - 7.2.10
- Population at risk within hazard zones - 7.2.11

We have used best practice in the estimation of these measures. Population at risk could be improved using more granular data regarding property locations and potentially site-specific QRA at high-risk locations.

Financial risk is relatively stable over time as the costs of repairing leaks and ruptures are treated as proactive costs. Increases are mainly due to higher costs of maintaining and replacing secondary assets as they deteriorate, such as nitrogen sleeves.

### 10.2.2. Improvement plan

Table 43 shows the improvement plan for the Pipelines model and indicative implementation timescales. Material changes arising from any improvement actions could potentially trigger a change to the Methodology (threshold to be agreed with Ofgem).

**Table 43 - Pipelines model improvement plan**

| Ref | Action | Potential Approach | Indicative Timescales |
|---|---|---|---|
| 1.1 | Develop a full risk based approach to quantity Availability risk, that enables alternative supply/demand scenarios to be modelled and the expected values chosen based on risk | As per Sites<br>Innovation project to bring together strategic planning, reliability and hydraulic modelling tools together into a single environment allowing the likelihood and consequences of asset failure to be explored under different prevailing demand conditions and NTS operating scenarios.<br>The **strategic planning models** will determine how often a specific supply/demand will occur, allowing the profile of scenarios to be generated<br>The **reliability models** will predict how often a failure consequence and account for asset connectivity and resilience (this may be done at a site level for major entry/exit points)<br>The **hydraulic models** will quantify the consequence of asset failure and account for NTS resilience and interconnectivity<br>These tools generally already exist but are not linked together | 2 -3 years |

| Ref | Action | Potential Approach | Indicative Timescales |
|---|---|---|---|
| | | A project plan will be developed pending completion of the ongoing RIIO-T2 compressor strategy analysis and a common approach adopted, where possible | |
| 1.3 | Review and benchmark of asset deterioration assumptions | As per Sites.<br>In safety-critical industries assets cannot be allowed to deteriorate to the point that they fail and generate consequences. Our current deterioration of assumptions is an improvement on those used for T1 as they have used a structured elicitation approach and involved a wider range of business experts.<br>However, future investment levels to manage this risk are sensitive to deterioration assumptions. Two potential improvements will be explored:<br>• Review whether our current elicitation process could be improved, and repeat if necessary<br>• Undertake wider benchmarking, UK and world-wide. This is dependent on having a consistent asset unit between benchmarking companies | 1 year |
| 1.7 | Use of site-specific Qualitative Risk Assessments (QRA) to inform site-specific safety assessments (population at risk) | As per Sites.<br>Current Safety risk in the model is based on generic assumptions.<br>The use of existing safety QRA reports will be explored for sensitive pipeline locations. If the data cannot be used directly in the Methodology an approach to undertake useful site-specific risk assessments will be developed.<br>Implementation of any site-specific QRA is subject to development of the revised approach. | Method: 1 – 2 years<br>Implementation: 3 - 5 years potentially |

| Ref | Action | Potential Approach | Indicative Timescales |
|---|---|---|---|
| | | This will also validate the current assumptions of the proportions of population killed or injured within each hazard zone.<br>Trial on a single high consequence site initially to prove method. | |
| 1.8 | Improve assessment of properties at risk within hazard zones | As per Sites.<br>A suitable mapping source was not available for use in the initial development of the Methodology and properties at risk is inferred using property boundary areas.<br>Purchase of the OS Mastermap spatial data by NGGT will allow property counts within hazard zones to be better quantified | 1 year |
| 1.9 | Include the impact of a wide-scale loss of a gas supply on Safety risk within our Availability/Reliability analysis | This has already been implemented, but the monetised risk values are not included in our current Methodology.<br>Requires further discussions with Ofgem | 6 months |
| 1.10 | Include the impact of a breakdown of the gas trading market (Societal impact) within our Availability/Reliability analysis | This would require a literature search to identify work already undertaken in this area. If suitable analysis does not exist a specialist study may need to be commissioned.<br>This is wider issue than just monetised risk and NOMs Methodology and an industry innovation project may be required | 2 -3 years |
| 2.1 | Align benchmarking and scaling analysis to ongoing updates and improvements in industry data sets | UKOPA, EGIG and IGEM/TD2 reports are updated on a frequent basis and our benchmarking/scaling results should be reviewed as these reports are updated.<br>There may also be the possibility of more detailed benchmarking with companies that operate similar | Annual update as part of Methodology review |

| Ref | Action | Potential Approach | Indicative Timescales |
|---|---|---|---|
| | | transmission networks, across Europe and world-wide. | |
| 2.2 | Improve quantification of leak sizes. Currently assumed to be 40mm for a corrosion leak | As per 2.1, this review will be carried out as updates to industry reports are published.<br>A short study to confirm if currently available data sets allow the profiling of leak sizes on transmission networks will be carried out prior to the first review | Annual update |
| 2.3 | Pipeline specific values for the distance between block valves sites, corresponding to the length of pipe that must be isolated and vented in the event of a gas leak/rupture will be incorporated | This data does not directly exist in the UPTIME data set that was used to build the Pipelines model. Values will be inferred spatially to assign a specific isolation length to each 12-metre pipe section | 6 months |
| 2.4 | Pipeline specific values leak run times will be estimated, based on the location and availability/accessibility of block valves to carry out the isolation, including remote valve control capability | This will assign a specific leak run time to each 12-metre pipe section. It likely that this will still involve expert judgement but better account of operational factors will be taken | 1 year |
| 2.5 | Ensure that corrosion defect growth rates remain aligned to Intervals2 as further data and evidence emerges | The rates of corrosion defect growth based on the quality of CP Protection are based on Intervals2, which contribute an industry standard approach. We propose to remain aligned to Intervals2 and will actively contribute to ongoing industry research<br>Incorporate ongoing learning from ongoing research into AC interference impacts on corrosion rates | Annual update |
| 2.4 | Improve understanding of the rate of cathodic protection system deterioration | There is no current hard evidence to support this value. It was originally estimated to be 23 mV/year based on an assumed linear deterioration rate. This value resulted in too many major corrosion defects. A value of 9 mV/year gave an expected number of pipeline inspections and repairs. | 2 – 3 years |

| Ref | Action | Potential Approach | Indicative Timescales |
|---|---|---|---|
| | | An innovation project will be instigated to better measure the rate and “shape” of CP system deterioration. | |

# 11. DOCUMENT CONTROL

| Version | Date of Issue | Notes |
|---|---|---|
| 0.1 | 14/12/2018 | Internal review |
| 0.2 | 17/12/2018 | Draft for Ofgem |
| 1.0 | 14/2/2019 | Final unredacted version for Ofgem |
| 1.1 | 12/7/2019 | Draft version, including 1 in 20 updates, for Ofgem review |
| 1.2 | 20/8/2019 | Redacted version for public consultation |

# APPENDIX D – EXPERT REVIEW SCOPE AND OBJECTIVES

The table below summarise the scope and approach for the expert review of Pipelines and Sites model, to be undertaken by independent experts.

| Task | Title | Summary |
|---|---|---|
| 1 | Validation of Pipeline Risk Model | Review of corrosion failure prediction methodology, including impact of: Pipeline wall thickness, coating,<br>CP deterioration<br>Number of corrosion features predicted and number requiring investigation (i.e. actioned digs). Number of corrosion failures with and without intervention.<br>Assessment of safety and loss of supply consequences predicted based on modelling of leaks and ruptures due to all damage mechanisms.<br>Consider the use of UKOPA and EGIG datasets to calibrate failure rate (leak and rupture) predictions for all damage mechanisms. Include explanations of any accepted modelling assumptions and applied caution in using industry data.<br>Review modelling of pressure reductions leading to supply restriction and prediction of number of supply interruptions and comment on whether the predicted risk is over or under valued.<br>Review modelling logic and predicted results for numbers of fires, explosions and fatalities |
| 2 | Validation of Sites Risk Model | Review of modelling of network resilience and site / sub site/unit availability. Consider predicted consequences of loss of supply scenarios, and site/ unit criticality. Consider how model could be used to assess different supply/demand scenarios.<br>Review modelling logic and predicted results for;<br>• Number of minor and significant leaks<br>• Number of ignited leaks<br>• Emission events and volumes<br>• Number of fires:<br>• number of public and employee fatalities<br>• loss of supply events |

| | | |
|---|---|---|
| | | • plant damage events<br>• Number of explosions:<br>• number of public and employee fatalities<br>• loss of supply events<br>• plant damage events<br>• Events leading site, part site and unit unavailability:<br>• Associated Availability/Reliability Constraint values<br>Provision of output reports from Site Model by ICS and details of model function/equations<br>The above will involve specific equipment analyses of:<br>• Entry Points<br>• Compressors<br>• Multi junctions<br>• PRS (Full offtakes)<br>• LDZ offtakes, Block valves, Pig Trap and Minimum Offtakes sites<br>The list of sites to be considered is given in Appendix 2<br>Assess impact of EGI failure on the site and impact on the network / supply constraints and resilience.<br>Consider predicted number of fatalities, including split between public and employee loss of life and injury. Review need to include fatalities/injuries due to pressure release events. Analyse risk diagram to ensure all relevant impact and failures modes have been considered. |