Programme Area: Energy Storage and Distribution

Project: Impact Analysis

Title: Future Networks: Impact Analysis Gas Final Report

Abstract:

This deliverable provides the final report for the gas case studies that have been assessed as part of the project. Please refer to the Executive Summary on Page 13 for an overview of the report content.

Context:

This project assessed the potential impact of selected, identified innovations on specific types of network (relating to heat, gas, electricity and hydrogen). Generic modelled networks will be developed utilising the 2050 Energy Infrastructure Cost Calculator model developed by a separate ETI project to understand the expected costs of certain types of network. The modelled networks will provide 'business as usual data' and a useful basis for further understanding of the impact of identified innovations in terms of overall cost and network performance.

Energy Infrastructure Outlook 2050

Innovation Impact Analysis - Gas - Final Report

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Glossary

Term	Definition
Abandonment	A term used in the context of the ICC to refer to the end of life of an asset and the costs associated with its removal / decommissioning. Abandonment costs are included in Lifecycle costs.
Assembly	A term used in the context of the ICC. These are collections of Components compiled using quantity multipliers to produce composite costs for these Assemblies.
Component	A term used in the context of the ICC. This is lowest level to which capital costs are disaggregated.
Feeder 10	Specific part of the existing gas transmission network in Scotland which has been considered for repurposing previously
First costs	In this study, the term first costs refers to the initial capital cost incurred on installation of new equipment or decommissioning of existing commitment. First costs are the indexed costs at the date of installation / decommissioning and are not discounted.
Lifecycle	A term used in the context of the ICC to refer to the cost profile of an asset over its life including new build, minor and major refurbishment and ultimate abandonment / decommissioning.
Losses	As energy is transported from generation through to end user, a share of it will get lost from the system through leakage or other factors. These losses are dependent upon a variety of factors and have a cost associated with the value of the energy lost. The value of these losses is not included in the ICC.
Net Present Value	This is the combined value of all future cash flows associated with a project discounted back to 2015. Net Present Value is the term used in the ICC however it should be noted that, as all cash flows in the cost tool are in fact costs (ie no 'values' or revenues are included), strictly the term should be Net Present Cost.
Normalised cost	The total cost of undertaking a project divided by a single parameter such as network length (km) to give a cost per km or population (No.) to give a cost per capita.
Project	A term used in the context of the ICC. Projects are collections of Assemblies with specific quantity multipliers combined to produce whole Project cost estimates.
Refurbishment	A term used in the context of the ICC to refer to the minor and major overhaul of an asset during its life
Repurposing	Modifying the system to make it capable of carrying a different substance from the one for which it was originally designed (e.g. natural gas pipeline repurposed to carry hydrogen).
Service connection pipe	Connecting pipes that branch off the gas main pipeline to supply the final consumers
Special crossings	When pipelines cross elements such as rivers, rail ways or roads.

Acronyms

Term	Definition
BCIS	Building Cost Information Services
BoQ	Bill of Quantities
BtG	Biomethane to Grid Plant
Capex	Capital Expenditure
CNG	Compressed Natural Gas
CO2	Carbon Dioxide
DNO	Distribution Network Operator
GIS	Geographical Information System
H2	Hydrogen
HGV	Heavy Goods Vehicle
HP	High Pressure
ICC	Infrastructure Cost Calculator
IP	Intermediate Pressure
LP	Low Pressure
LTS	Local Transmission System
MEAV	Modern Equivalent Asset Value
MP	Medium Pressure
MSOA	Middle layer super output area
Nm^3	Normal cubic metre
NPV	Net Present Value
NTS	National Transmission System
Opex	Operational Expenditure
PRS	Pressure Reduction Station
Repex	Replacement Expenditure

1 Executive Summary

1.1 Project overview

This study brings together two strands of work within the ETI focused on understanding the cost and performance of energy infrastructure in the UK. On the one hand, the research projects undertaken by various teams looking at specific scenarios and innovations, and on the other, the Infrastructure Cost Calculator (ICC – formerly referred to as the Energy Infrastructure Outlook 2050 Cost Tool), an analysis tool based on an extensive database of energy infrastructure costs.

The research questions addressed can be divided into two broad categories:

- Firstly, questions around the configuration and cost of representative (or 'generic') networks applicable to particular situations.
- Secondly, questions around the potential impact of selected, identified innovations on specific types of network.

This report considers the research questions posed in relation to natural gas. Separate reports are available for electricity, heat and hydrogen.

The work undertaken here made use of the first version of the ICC and as such also acted as a testing phase. Some issues arose in relation to the output of the tool particularly in respect of the treatment of operational and lifecycle costs. These findings are being fed into a parallel project to develop a second version.

1.2 Key findings

Some findings are the same across all projects. These include:

- First costs are higher at later installation dates. This is due to the impact of the real-term cost trends in the ICC applied to labour, material and plant costs. There are clearly alternative views on cost trajectories and these will influence the relative impact of deferring installation.
- NPV[1] (Capex plus Opex) is lower for projects installed at a later date. Two factors come into play here: one, as expected, is the impact of discounting; the other is the way in which lifecycle costs are modelled in the ICC and the fact that the analysis has been undertaken for a fixed period of 60 years (2015 to 2075) irrespective of the installation date. Lifecycle costs include for a major refurbishment (100% of new build costs) at a fixed period after first instalment. For later installation dates, this major refurbishment may be beyond the analysis period and therefore not be included in the NPV calculation.
- Opex costs represent a relatively small proportion of whole life costs. It should be noted that the modelling of Opex is to be revised in the next version of the ICC which may influence the outturn values (see Section 3.2.4). Note also that Opex does not include the cost of any energy lost from the system.

A summary of findings specific to each project is given in Table 1-1.

[1] In this study, the term Net Present Value (NPV) refers to the combined cash flows of a project over the project period discounted back to 2015. Note that as all cash flows in this analysis are costs (ie no revenues are included), strictly the term should be Net Present Cost. NPV is used to be consistent with the terminology used in the ICC.

Table 1-1 Key findings for gas network research projects

Ref*	Title	Key findings
		Generic
G-G-2	Representative Gas Distribution Model: connecting networks to transport sites at different capacities for different network lengths, in rural, semi-urban, urban and London contexts	• Context is a strong influencer of costs, with costs increasing from rural through to urban and London. This is due to the higher costs of installing pipework in more congested areas. • Pipe costs dominate the overall network cost, particularly for the longer network lengths. • Pipe capacity and hence size (6" MP or 12" LP) has some influence over cost at the longer network lengths where pipe costs are the most significant element. At these longer lengths, the MP network costs are lower than the LP network costs. • Normalised costs (ie costs per km) fall with increasing network length. This is largely due to the spreading of the single compressor cost over a longer network length.
G-G-3	Generic decommissioning costs (transmission), 100km length at different capacities / pipe sizes, rural context	• Decommissioning costs (NPV Opex in 2015 for networks decommissioned in 2020) are of the order of £90k/km. • Decommissioning of the pipework comprises around 80%-85% of cost, with the remaining 15%-20% relating to decommissioning the conversion station. • Pipe size has a minimal impact on cost.
G-G-4	Generic decommissioning costs (distribution) for different contexts and populations	• Decommissioning costs (NPV Opex in 2015 for networks decommissioned in 2020) range from around £250k/km in London down to £60k/km in rural areas. • The relative importance of the different Assemblies in terms of share of cost varies with context: decommissioning the LP network represents the largest share of cost in rural areas (60%) and decommissioning domestic connections represents the largest share of cost in London areas (58%).
G-G-5	Generic operational costs associated with remaining part of a partially decommissioned network (distribution)	• In each context, reduction in Opex with increasing decommissioning is linear. This is a reflection of the modelling approach, where both direct and indirect costs are prorated to asset value. • Direct costs represent approximately 80% of the overall Opex for gas distribution infrastructure with indirect costs (including both closely associated costs and business support costs) making up the remainder. • Decommissioning (abandonment) costs make up a small share of overall cost with the NPV of Opex saved being 5 to 10 times higher. • After partial decommissioning, NPV (Opex plus abandonment) of the partially decommissioned network per connection served increases as the percentage of network decommissioned rises. • This task is particularly affected by the approach to modelling Opex in the ICC which is to be revised in the next version.
		Innovation
G-I-6	Gas transmission network: repurposing to hydrogen for different network lengths in a rural context	• Overall the innovation of repurposing existing natural gas transmission networks to carry hydrogen is roughly half the cost (NPV in 2050 for repurposing undertaken in 2020) of abandoning those same networks and building hydrogen pipelines from scratch • NPV/km decreases slightly with network length for both the innovation and the counterfactual
G-I-7	Gas transmission network: repurposing to carbon dioxide for single network length in rural	• The task compared repurposing existing gas transmission pipelines to carry gas phase CO_2 compared with building new transmission pipelines to carry dense phase CO_2. Although operational conditions of pressure and

Ref*	Title	Key findings
	and semi-urban contexts	temperature (P, T) were different, they maintain the same CO_2 capacity flow (8m tonnes/year). • Both first costs and NPV are higher for the counterfactual (new build) than for the innovation (repurposing) due to the high costs of installing new transmission pipelines. • As expected, all costs are higher (around 10-20%) in a semi-urban context than a rural one due to higher costs associated with more dense / congested environment.
G-I-8	Natural gas conversion: installation of Biomethane to Grid injection points with different network lengths and capacities in rural and urban contexts	• The cost of installing Biomethane to Grid plant is higher in urban areas than in less dense rural ones mostly due to the additional cost associated with installing pipework associated with the connection point in more congested areas • Normalised costs per km fall with increasing network length • Normalised costs per m^3 gas decrease with increasing gas injection capacities

** One research question, G-G-1, was subsequently removed from scope. The original number referencing has however been retained.*

1.3 Further work

Further work could be undertaken on some of the tasks as follows:

- G-G-2: consider the impact on cost of including a metering and control station and connection to the network.
- G-G-3: consider the impact on cost of including the upstream compressor.
- G-G-4: the reliance on single locations to represent particular types of location remains a limitation of the analysis. Further work could include the analysis of additional locations to better understand and develop general cost trends.
- G-G-5: as this task explores Opex costs, the results will be particularly affected by the approach taken to modelling Opex in the ICC. Results therefore are likely to differ if the task is re-run using ICCv2.
- G-I-7: further more detailed costing could be undertaken on the gas compressor used in the counterfactual.

In addition, all tasks could be re-run in the second version of the ICC. This version will use a revised approach to modelling Opex and lifecycle costs which should address the issue encountered in this study in relation to the use of a fixed analysis period. ICC v2 will also incorporate different costs trends which will impact on results.

2 Introduction

2.1 Overview

The ETI and its Members are interested in the cost effective deployment of energy infrastructure in the UK. By 2050 the UK will need to be meeting stringent targets requiring an 80% reduction in CO_2 emissions, whilst maintaining a sufficient supply of energy. In order to appropriately assess the opportunities for meeting these targets, it is necessary to understand, amongst other things, the costs and performance of the energy infrastructure that will carry energy from where it is generated to where it is consumed.

The study brings together two strands of work within the ETI aimed at addressing these issues. On the one hand, the research projects undertaken by various teams looking at specific scenarios and innovations, and on the other, the Infrastructure Cost Calculator (formerly referred to as the Energy Infrastructure Outlook 2050 Cost Tool), an analysis tool based on an extensive database of energy infrastructure costs. The tool is being used to enable the research teams to answer specific research questions.

The research questions addressed in this study can be divided into two broad categories:

- Firstly, questions around the configuration and cost of representative (or 'generic') networks applicable to particular situations. These network models are required to understand the expected costs, etc of certain types of typical network, the intention being to enable expedited assessment of certain types of network (at a high level) in future as the need arises, e.g. through making adjustments to the models provided as part of this work.
- Secondly, questions around the potential impact of selected, identified innovations on specific types of network. For example, questions around the difference in cost and performance between repurposing natural gas pipelines to carry hydrogen and building hydrogen pipelines from scratch. The generic networks provide the counterfactual against which the innovations can be compared.

This report considers the research questions posed in relation to natural gas. Separate reports are available for electricity, heat and hydrogen.

The study was undertaken by BuroHappold with the Sweett Group and a team of external specialists to validate the technical scoping (see Appendix A).

2.2 Approach and methodology

An overarching methodology was developed applicable to all research questions. As illustrated in Figure 2-1, key steps were to:

1. Agree the outline scope of each of the research questions with ETI.
2. Develop a detailed scope for each of the research questions including a clearly defined network design and associated Bill of Quantities (BoQ).

An important aspect of this step was to ensure that, as far as possible, the network designs were representative of the particular situation being modelled. To support this, a team of experts was engaged to provide a robust approach to validation and to ensure that assumptions and simplifications made were reasonable. The detailed scoping methodologies are particular to each research question and are covered in the relevant chapter of this report. Full copies of all Detailed Scoping reports are available separately from the ETI.

3. Cost the network design using the ICC, including costing any additional infrastructure elements not already available. For this step, the details of the Bill of Quantities generated during the detailed scoping phase were input to the tool under various contexts, capacities and timescales, thereby generating a number of data points on which to perform the analysis.

4. Analyse the cost data generated by the tool in the context of the research question and, where relevant, compare the cost of the innovation with that of the generic counterfactual.

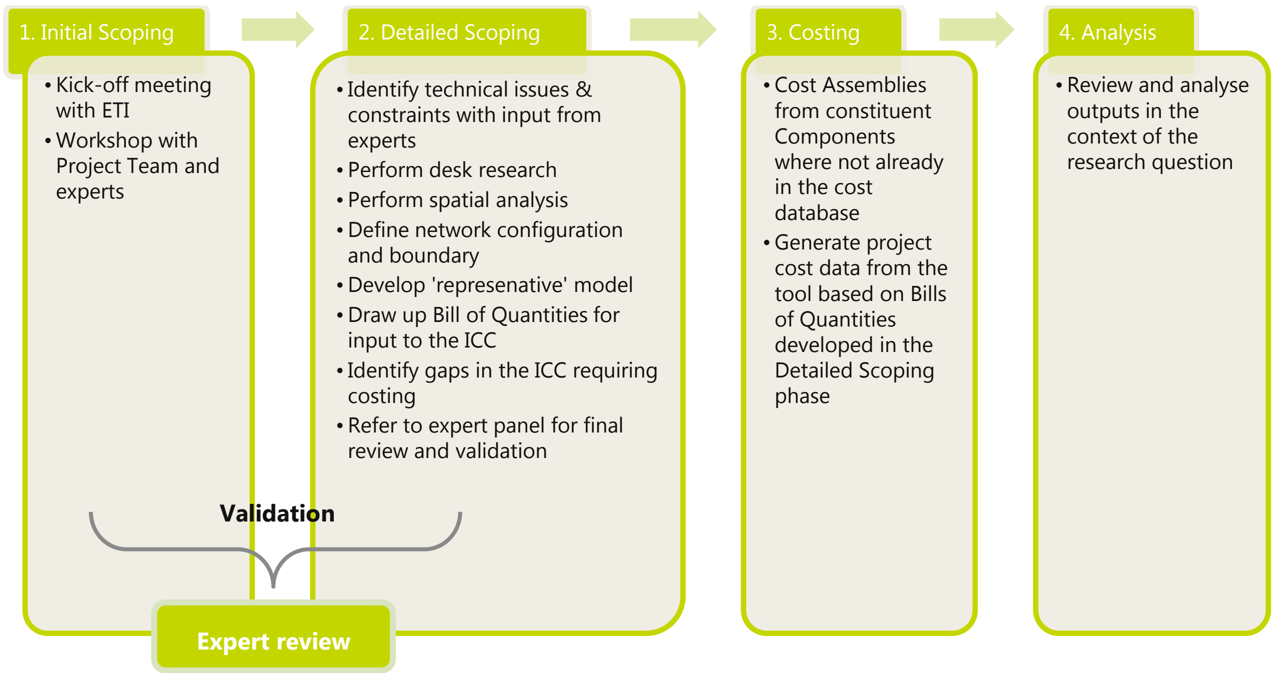


Figure 2-1 Outline methodology applied to all research questions

The ICC that underpins this analysis is a tool that was commissioned by ETI in 2012 and created by Buro Happold and the Sweett Group. It contains a wealth of information on the capital and operational costs of infrastructure related to the four energy vectors, electricity, gas, heat and hydrogen. To provide context for readers of this report, further background information on the structure and functionality of the tool is provided in Chapter 3.

2.3 Scope

A summary of the heat research questions covered in this study is provided in Table 2-1. As noted above, these questions arose from within ETI's operational and strategic teams, and as such are specific to particular areas of work on which they are engaged. The table outlines the context of each research project and the value this analysis provides.

Table 2-1 Summary of gas research questions covered in this study

Ref	Title	Description	Context / value added
GENERIC NETWORKS *			
G-G-2	Representative Gas Distribution Model: connecting networks to transport sites	Representative new build gas distribution networks for connecting to depot refuelling sites for Heavy Goods Vehicles (HGVs).	Rural, semi-urban, urban, London. Provides generic costs per km that can be applied to different network configurations.
G-G-3	Generic decommissioning costs (transmission)	Full decommission of gas transmission network in rural areas	Rural. Provides generic decommissioning costs per 100km of network length.
G-G-4	Generic decommissioning costs (distribution)	Full decommission of gas distribution network in rural areas	Rural, semi-urban, urban and London. Provides generic decommissioning costs per connection and per km.
G-G-5	Generic operational costs associated with partially decommissioned network (distribution)	Generic network operational costs associated with remaining part of partially decommissioned network	Rural, semi-urban, urban and London. Provides information on the impact of decommissioning part of a gas network on operational costs for different densities and populations.
INNOVATIONS			
G-I-6	Gas transmission network: repurposing to hydrogen	Comparison of the costs of repurposing natural gas transmission pipelines to hydrogen compared with decommissioning gas and building new hydrogen pipelines.	Rural. Impact of innovation.
G-I-7	Gas transmission network: repurposing to carbon dioxide	Comparison of the costs of repurposing natural gas transmission pipelines to carbon dioxide compared with decommissioning gas and building new carbon dioxide pipelines.	Rural. Impact of innovation.
G-I-8	Natural gas conversion: gas injection points	Costs of incorporating injection points for bio-gases or synthetic gases into the gas transmission and distribution networks.	Rural and urban. Cost comparison in different contexts and capacities.

** One research question, G-G-1, was subsequently removed from scope. The original number referencing has however been retained.*

2.4 Report structure

This report synthesises the work undertaken on each of the research questions and presents and discusses the findings. A chapter is included for each question using the project reference provided in Table 2-1. The analysis is based on the detailed scoping exercise that was undertaken for each project. The Detailed Scoping reports are available separately from the ETI.

An overview of the ICC is provided in Chapter 3 to provide context to the reader in the interpretation of the results.

3 Infrastructure Cost Calculator

3.1 Introduction

This chapter explains the workings of the ICC in the context of this study. Full details of its structure and operation can be found in the ETI Energy Infrastructure 2050 Final Report, 22 November 2013, available from the ETI.

This chapter should be considered as a reference chapter to provide background to the interpretation of the data.

3.2 Cost Tool overview

The ICC is a structured database containing cost data for a broad spectrum of infrastructure elements for electricity, gas, heat and hydrogen in respect of transmission, distribution, conversion, connection and storage. It was developed over a two year period by Buro Happold in close association with the Sweett Group, combining expertise in technical design and cost modelling. The tool is under development with a second version due to be released towards the end of 2015. The analysis presented in this report was undertaken using the first version, completed in November 2013.

The following sections highlight some of the key features of the tool that are of relevance to this study.

3.2.1 Tool structure

The tool uses a modular approach to build up costs, from Component to Assembly to Project as shown in Figure 3—1.

- **Components** represent the lowest level to which capital costs are disaggregated. For example, civil engineering cost Components may include excavation, filling, surface re-instatement, etc.

- **Assemblies** are collections of Components compiled using quantity multipliers to produce composite costs for these Assemblies. Components are assembled for new build, refurbishment, re-purposing and abandonment within Assemblies, as appropriate. Assemblies are the key 'building blocks' of the tool with each Assembly being clearly defined in a technical diagram that gives the element boundary, typical configuration and capacity range.

  The name given to each Assembly includes the following descriptors:

  - Vector: Electricity, Gas, Heat, Hydrogen
  - Function: Transmission, Distribution, Conversion, Connection, Storage
  - Mode: eg. NTS, HP, IP' MP, LP, None
  - Rating: eg 26" gas pipe
  - Installation: Buried, Overhead, Offshore, Tunnelled, None

  This naming structure is used wherever Assemblies are referred to in this report.

- **Projects** are collections of Assemblies with specific quantity multipliers combined to produce whole Project cost estimates. Projects can be attributed with specific context (urban, rural, etc), scale and region to allow Assembly costs to be appropriately modified during calculations.

This study makes use of the Project functionality of the tool. A detailed description of how this works and how the data flows from Component to Assembly to Project is provided in Appendix B.

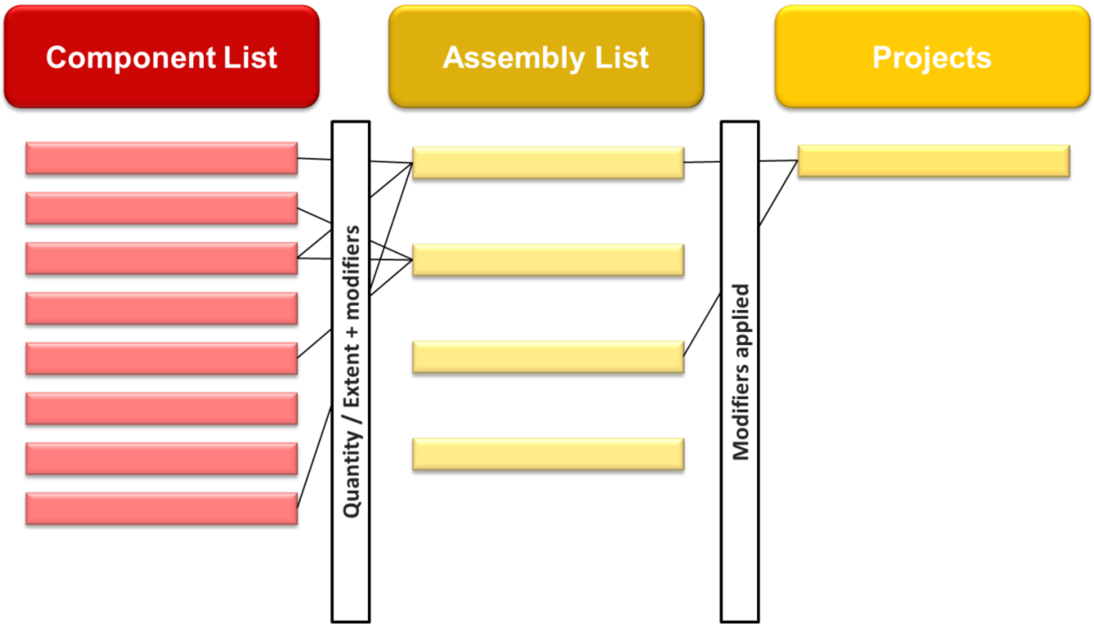


Figure 3—1 Outline of Infrastructure Cost Model structure

3.2.2 Cost data

The approaches to capital and operational costs in the tool are different, primarily due to the difference in availability of data.

Capital costs are derived using a 'bottom up' approach whereby each Component is costed separately as data is generally available at this level. The data has been built up from a number of sources which vary in quality from strong to weak. Items for which data is weakest are generally those which are relatively new and for which there are few precedents. The quality of the data is referenced within the tool.

A more 'top down' approach is used for operational costs, based on regional and / or network wide data that reflects the way that networks tend be managed and reported upon, particularly in the case of the regulated utilities. Operational costs include for direct and indirect costs and are based on the published network costs of the Distribution Network Operators (DNOs)[2]. Profiles for changes in operating costs over time are described in Section 3.2.4 below.

[2] For a full description of how operational costs were applied in the tool, see the *ETI Energy Infrastructure 2050 Final Report*, 22 November 2013, available from the ETI, in particular Chapter 7 and Appendix G, *Opex Framework for Energy Infrastructure*, PPA Energy, April 2013.

3.2.3 Component cost rate modifiers

All Components are given a baseline cost, split into materials, labour and plant. In order to reflect the fact that costs vary in different contexts and under different circumstances, modifications (expressed in percentage changes) to this baseline cost are allowed for. Thus for example, while the baseline cost for civils associated with the installation of 12" LP gas pipeline in a rural context might be £135/m, the ICC assumes that semi-urban costs are 130% of this and urban costs are 400%. Similarly, cost rate modifiers are applied for different scales of installation, and different environments such as ground conditions.

To take account of the variation of costs across the UK, the current version of the ICC applies Regional Tender Price Indices as extracted from Building Cost Information Service (BCIS). Thus for example, the cost of projects installed in London are inflated by 122% against the 'All of UK' baseline.

3.2.4 Operational and lifecycle cost profiles

The ICC recognises that different infrastructure elements are likely to have different cost profiles over time. This is accounted for through the application of different operational cost and lifecycle cost profiles.

- **Operational cost profiles**: The most significant impact on operational costs over an asset's life is the failure rate and therefore the need for reactive maintenance. The failure rate is assumed to be mainly influenced by the asset type, either active or passive. On this basis, two profiles are incorporated into the tool to represent the variation in operating cost over the life of the asset (from 0 to 100% of the defined asset life) as illustrated in Figure 3—2. The area under each profile curve is taken as the total operating cost for the asset over its life and the operating cost in any given year is determined as a proportion of the total operating cost that is applied in that year[3].

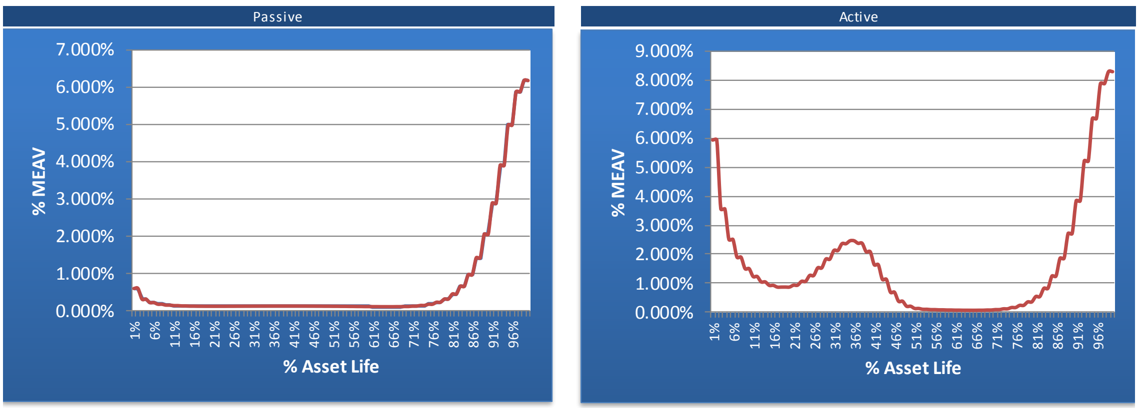


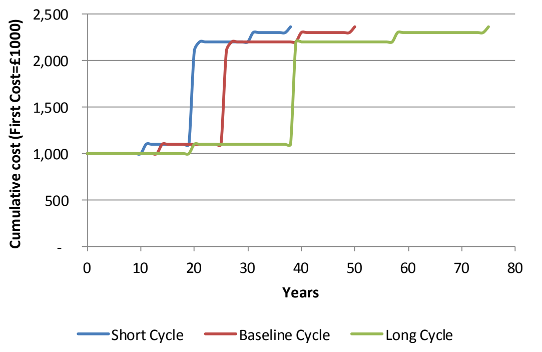
Figure 3—2 Passive and Active Opex profiles in the ICC v1[4]

- **Lifecycle cost profiles**: The lifecycle profile defines the periods of major and minor replacement and the percentage replaced in each of these cycles. It also includes abandonment at end of life. The cycles are deemed to differ according to context (ie assets are assumed to have a shorter lifecycle in an urban context than in a rural one). Two examples of lifecycle profiles used in the tool are shown in Figure 3—3[3].

[3] The modelling of Opex and lifecycle costs will be changed in v2 of the ICC. In v1, Opex comprises failure costs and indirect Opex only, with cyclical replacements of capital equipment and abandonment being modelled through the lifecycle profiles as described here. In v2, the method will use combined Weibull curves to represent failure costs, indirect Opex and replacements of capital equipment, with these latter costs being spread over a number of years, rather than all at once as in v1.
[4] MEAV is the Modern Equivalent Asset Value and is used as the basis for calculating operational costs.

Profile 1: 25 Year asset life

Lifecycle Parameters	% Replaced	Cycle (Years)		
		Short	Baseline	Long
Major Replacement	100%	19	25	38
Minor Replacement	10%	10	13	19
Abandonment		38	50	75
Cycle modifier		Urban	Semi-Urban	Rural
		90%	100%	120%



Profile 2: 40 Year asset life

Lifecycle Parameters	% Replaced	Cycle (Years)		
		Short	Baseline	Long
Major Replacement	100%	30	40	60
Minor Replacement	10%	15	20	30
Abandonment		60	80	120
Cycle modifier		Urban	Semi-Urban	Rural
		90%	100%	120%

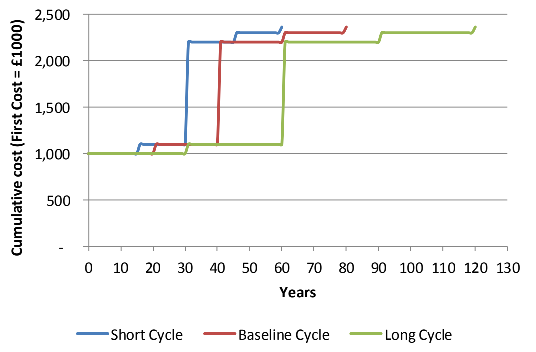


Figure 3—3 Lifecycle profiles in the ICC v1

3.2.5 Trends

The tool includes two specific types of cost trend that are applied to Component data.

The first are general real-term cost trends applied specifically to labour, materials and plant. High, medium and low increase trends are allowed for within the ICC, with the default trend – used in this analysis – being medium (Figure 3—4). Alternative versions of these trends are being developed for future analysis.

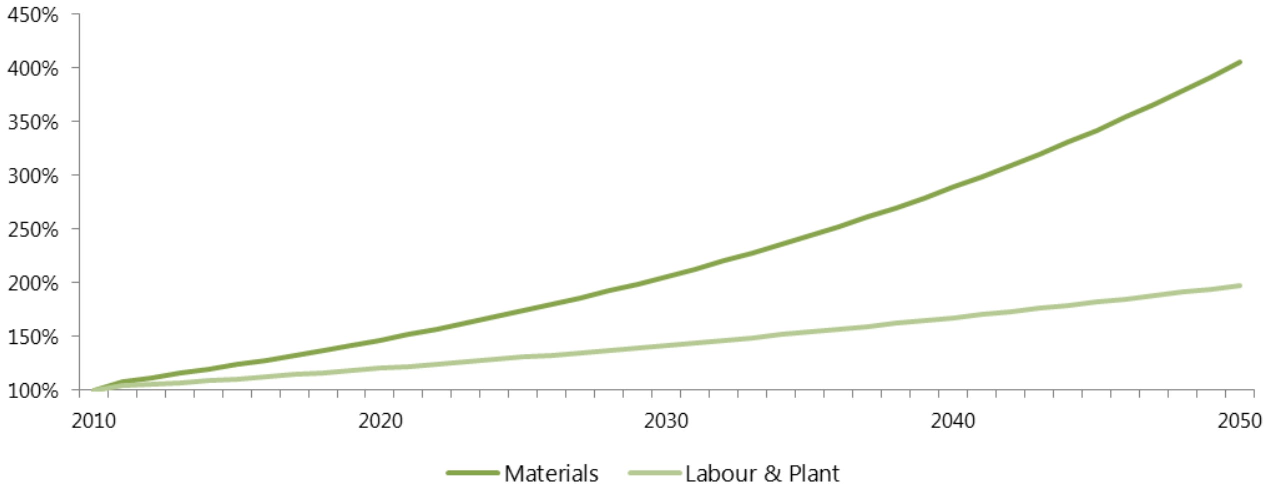


Figure 3—4 Medium general real-term cost trends as applied in the analysis

The second are technology cost curves that relate to the different cost trajectories arising as a consequence of the maturity of the underlying technology. Five curves are available within the ICC as illustrated in Figure 3—5. These are taken from a report prepared by EA Technology for Ofgem[5] and are made up as follows:

[5] http://www.ofgem.gov.uk/Networks/SGF/Publications/Documents1/WS3%20Ph2%20Report.pdf

Type 1; Rising (based on an average of the Steel and Aluminium cost curves)

Type 2; Flat (to represent no change in cost)

Type 3; Shallow reduction (based on an average of offshore wind farm costs and flat line)

Type 4; Medium reduction (based on the cost curve for offshore wind farms)

Type 5; High reduction (based on the cost curve for laptops)

The majority of Components are categorised as Type 2 (flat) but steeper reduction curves are applied to more innovative technologies.

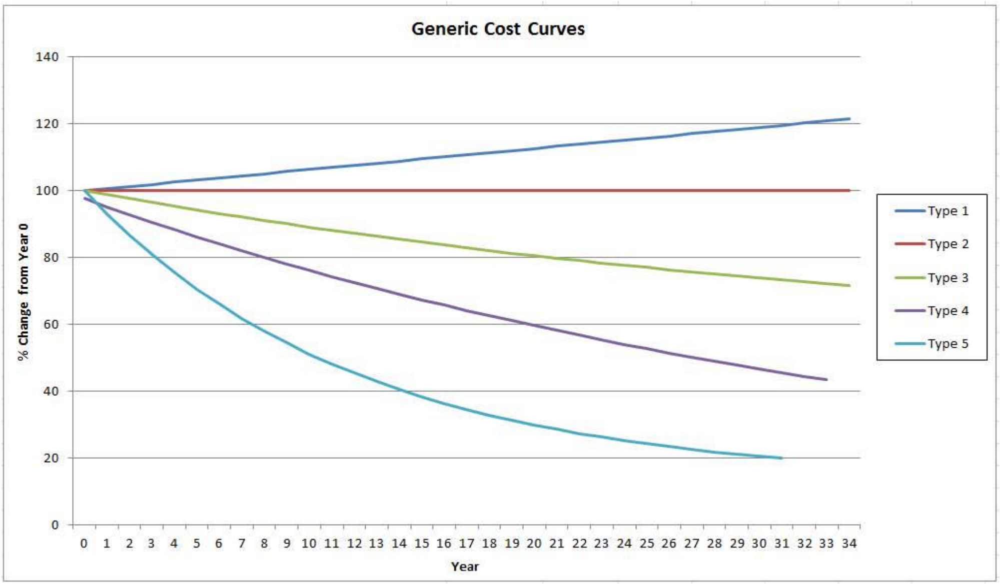


Figure 3—5 Technology cost curves incorporated into the ICC v1

3.2.6 Projects

For the purposes of this study, the key functionality of the tool is the costing of Projects. A Project is essentially a Bill of Quantities (BoQ) based on a specific network design, the BoQ comprising a list of Assemblies each with a particular quantity.

Project costs are built up within the database such that cost data flows from the Components through to the Assemblies and on to the Project. As noted above, the tool allows for baseline costs to be modified according to particular circumstances of installation. Thus for example, different projects may be installed in different ground conditions, or in different contexts (urban, semi-urban, rural) resulting in different out turn costs.

A detailed description of how the cost rate modifiers are applied and the data flows from Component to Assembly to Project is provided in Appendix B.

3.3 Application of the ICC in this study

This section outlines how the ICC has been used in this study, describing the treatment of all input variables and the derivation of outputs.

3.3.1 Inputs

As noted above, the ICC allows for a variety of factors to be specified in order to tailor the analysis to the specifics of a particular project. For this study, some of these have been applied specifically for each project while some have been fixed across all projects as a practical response to managing the amount of data generated. A description of each variable is given below.

1. Add on costs (contingencies etc): these are calculated as a percentage of Capex and have been set at the same rate for all projects in this analysis as detailed in Table 3-1.

Table 3-1 Add on costs applied to all projects

Parameter	Description / details	Value
Project management, Engineering, etc	% to be added to Capex	12%
Preliminaries	% to be added to Capex	15%
Contractor overheads and profit	% to be added to Capex	5%
Contingencies	% to be added to Capex	10%

2. Cost trends for labour, materials and plant: all projects use the Baseline trend (see Section 3.2.5).

3. Technology maturity: these are specified at Component level depending on the nature of the Component (see Section 3.2.5).

4. Installation conditions: excavation difficulty, ground contamination and ground water are the same for all projects as outlined in Table 3-2.

Table 3-2 Ground conditions applied to all projects

Parameter	Condition	% of ground in specified condition
Excavation difficulty	Ground is soft and clean. No rock or hard material	60%
	Intermittent rock / hard material (20% by volume)	30%
	Prolific rock / hard material (75% by volume)	10%
Ground contamination	Ground is clean and inert	50%
	Ground is mildly contaminated	30%
	Ground is heavily contaminated	20%
Ground water	Little or no ground water	80%
	Intermittent dewatering required	20%
	Continuous dewatering required	0%

5. Region: all projects (rural, semi-urban and urban) are designated as 'All of UK' with the exception of the London context which is designated as London (see Section 3.2.3).

6. Context: this is a variable within the analysis, thus projects are defined as urban, semi-urban or rural as specified in the relevant Detailed Scoping document.

7. Optimism bias: this is the same for all projects as outlined in Table 3-3.

Table 3-3 Optimism bias applied to all projects

Parameter	Description / details	Value
Optimism bias	% Increase to estimated NPV to allow for Optimism Bias:	Capital Expenditure
	Lower	6%
	Upper	66%

7. Cash flow parameters: these are the same for all projects as outlined in Table 3-4. In particular it is important to note that cash flows are derived for the period 2015 to 2075 (ie a 60 year period) regardless of installation date. Thus a project installed in 2040 will have cash flows over the period 2040 to 2075 and these cash flows will be discounted back to 2015.

Table 3-4 Cash flow parameters applied to all projects

Parameter	Description / details	Value
Start year	This is the date at which the NPV is calculated.	2015
Lifecycle Assessment Period (years)	This is the total period over which project cash flows are assessed.	60
Discount rate	From 2015	3.5%
	From 2046	3.0%

3.3.2 Outputs

The key outputs from the ICC used in the analysis are the Net Present Value (NPV)[6] of the capital and operational costs over the project life; the first cost, being the initial capital cost, undiscounted; and the relative cost of different Assemblies within the network. These are described below.

- **The capital cost NPV** is the NPV of cash flows associated with the initial installation of the asset plus those associated with replacement and abandonment. Cash flows are initially discounted at 3.5% and at 3.0% from 2046.

  An example of these cash flows is illustrated in Figure 3-6. This graph is an output of the tool and shows the annual cash flows associated with capital and replacement costs for a new build hydrogen distribution network including pipes, conversion stations and connections. The project assumes all assets are installed in 2020, with subsequent cash flows associated with minor and major replacement cycles occurring periodically thereafter. As noted in Section 3.2.4 above, the minor and major replacement cycles are determined by the lifecycle profile attributed to the Assemblies in the project as annotated in the graph below.

[6] Note, throughout this report, the term Net Present Value (NPV) has been used to refer to discounted cash flows as this is a convention as used in the ICC. However, it should be noted that as all cash flows are in fact costs (ie no 'values' or revenues are included), strictly the term should be Net Present Cost.

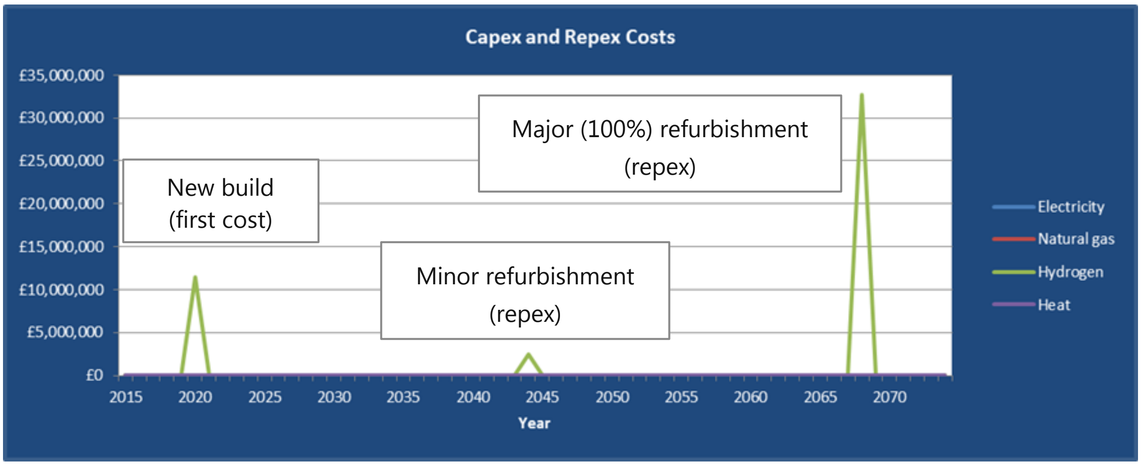


Figure 3-6 Graphical output from ICC showing capital and replacement cost cash flows over the life of a project with assets installed in 2020

An important point to take into account in the interpretation of the results in this report is the impact on lifecycle costs of deferring installation. Thus, if the same network shown above were installed in 2040 rather than 2020, the lifecycle cash flows would be as illustrated in Figure 3-7. The new build costs are now in 2040 and are higher than in 2020 due to the impact of inflation (Figure 3—4) with the minor refurbishment occurring in 2064. However, as the period for calculating the NPV is fixed at 60 years from 2015, the major replacement is beyond the end of the assessment period and therefore not included in the cash flow. This can have a significant impact on NPV when comparing costs at different installation dates.

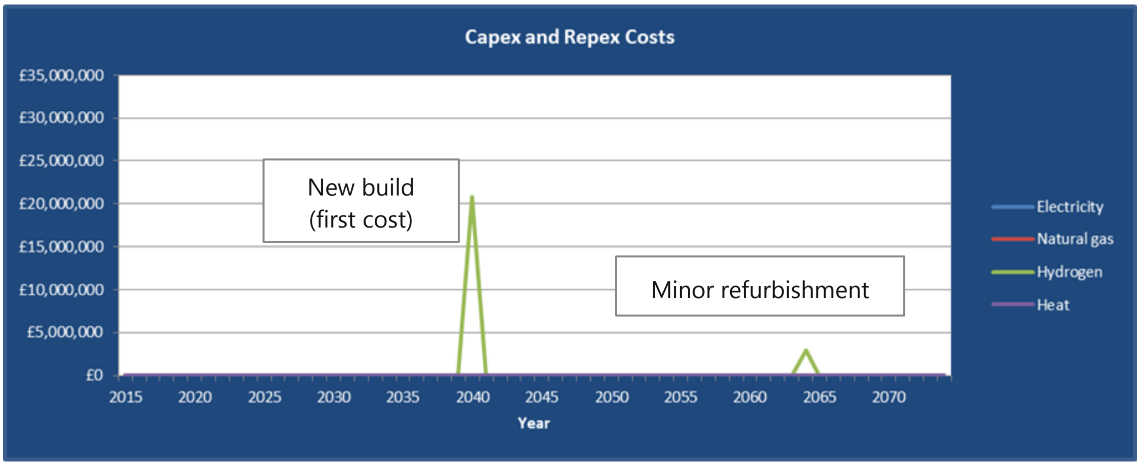


Figure 3-7 Graphical output from ICC showing capital and replacement cost cash flows over the life of a project with assets installed in 2040

- **The Opex NPV** is the NPV of all operational cost cash flows associated with all Assemblies in the Project over the assumed project life.

An example of these cash flows is illustrated in Figure 3-8. This graph is an output of the tool and shows the annual cash flows associated with operational costs for a new build hydrogen distribution network including pipes, conversion stations and connections. As noted in Section 3.2.4 above, operational costs are determined by the operational cost profile attributed to the Assemblies in the project.

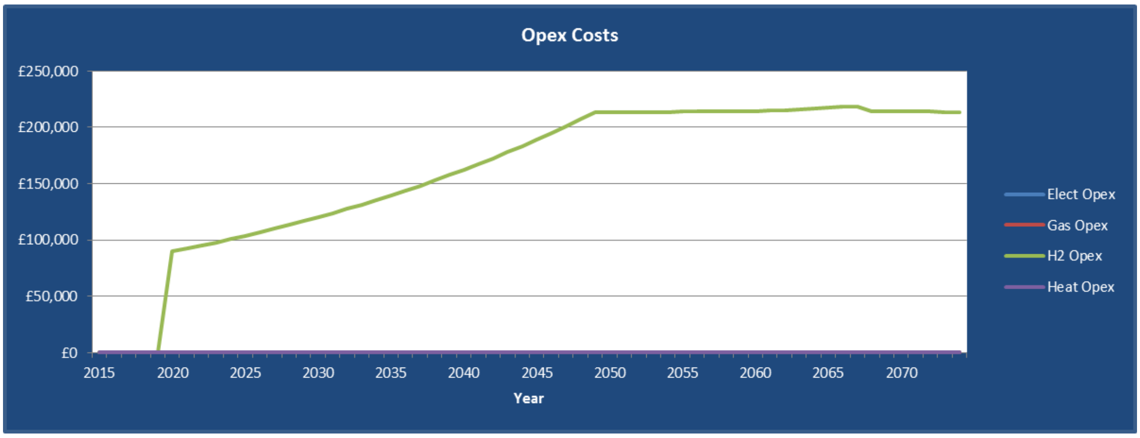


Figure 3-8 Graphical output from ICC Cost Tool showing operational cost cash flows over the life of a project

- **First cost** is the undiscounted cost of the initial installation of the asset including preliminaries and contingencies etc. but without considering replacement and abandonment. This has been included in the analysis to contextualise costs excluding Repex and Opex. First costs are higher at later installation dates due to the impact of the future cost trends (see Figure 3—4.

- **Relative cost of Assemblies:** The analysis also explores the relative costs of different Assemblies within a network to understand key cost drivers. The costs being compared are the total undiscounted costs of all Capex and Repex associated with that Assembly over the project life.

3.4 Considerations and limitations

The cost outputs of the tool and thus the analysis arising need to be viewed with the following issues in mind:

- Technical scope

  As noted above, the key units or 'building blocks' in the tool are the Assemblies. Each Assembly is defined so as to be representative in terms of configuration, capacity, size etc of a 'typical' piece of infrastructure. Given the wide number of alternative designs and configurations available in practice, it is recognised that selecting a single 'typical' design reduces the accuracy of a detailed study. For the purposes of this high level study however, the designs within the tool are considered to be adequate. Where no appropriate Assembly was available in the tool for a particular research question, a new one was added.

- Opex

  The approach taken to operational costs was simplified for the purposes of this first version of the tool. These are being refined for the second version.

- Losses

  No account is taken of losses occurring over the network. Losses were not included in the tool due to their dependence on network design, which is outside the scope of the tool.

- Lifecycle profiles

Three lifecycle profiles are included in the tool, all of which include for a major (100%) replacement after a certain period. The inclusion of lifecycle costs in the Capex NPV influences results particularly where installation occurs at different dates given that the assessment period remains fixed (ie 60 years from 2015 to 2075).

It should be noted that the modelling of lifecycle costs will be revised in the next version of the tool, taking a more probabilistic approach and thereby allowing for cash flows to be smoothed. In addition, lifecycle costs will be included in with Opex costs rather than with Capex costs.

- Project cost parameters

  The tool allows for the variation of a number of different parameters in relation to ground conditions, prelims costs, optimism bias etc. For the purposes of this initial study, these have been fixed for all projects. They can however be varied should more detailed analysis be required at a later date.

- Economic trends

  Subsequent to the initiation of this project, the economic trends for materials, labour and plant costs have been revised. These revisions have not been taken into account in this analysis.

Overall, the results of the analysis need to be considered in the context of the first version of the ICC. As well as providing cost information for ETI research teams, the exercise has also identified issues to be addressed in the second version of the tool.

4 G-G-2 Representative Gas Distribution Model: connecting networks to transport sites

4.1 Research question overview and scope

This research question was concerned with the cost of connecting natural gas refuelling depots to the natural gas distribution network. The scope was focused on:

- Connections from gas networks to existing transport sites such as a return to base logistics centre located adjacent to a motorway and servicing a large Heavy Goods Vehicle (HGV) fleet.
- Delivery of Compressed Natural Gas (CNG) by pipeline in the LP/MP pressure range.

The schematic in Figure 4-1 shows the boundary, assemblies and network layout of this project. Essentially the network comprises distribution pipelines connecting to a depot which includes gas compressors and a storage tank. The scope excludes connections to the distribution network and the actual delivery apparatus to the vehicle. In the context of the ICC, the Assemblies used to build the network are:

- LP - Buried: 12" gas pipe [20,000 m^3/day]
- MP - Buried: 6" gas pipeline [300,000 m^3/day]
- Conversion. Gas Compressor up to 300bars with gas storage tank [42,500 m^3/day & 170,000m^3/day]

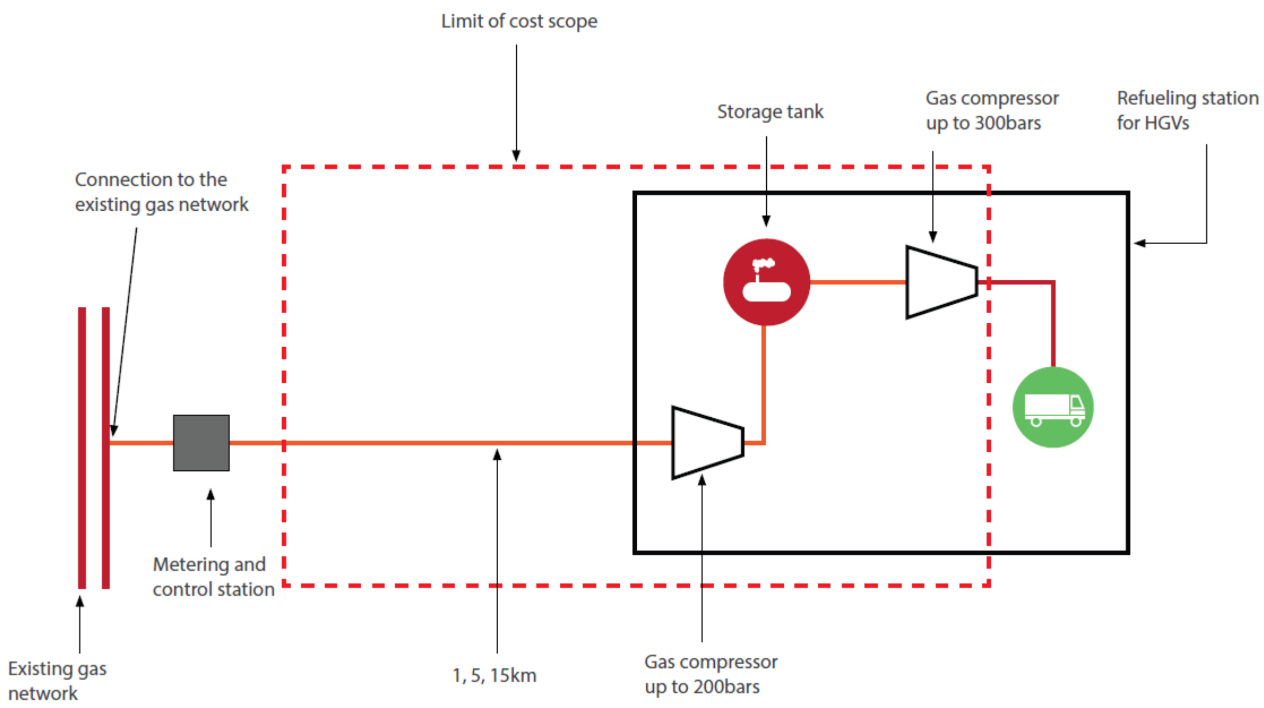


Figure 4-1 Network schematic indicating scope boundary

The research question was concerned with exploring costs in different contexts, capacities and periods as summarised in Table 4-1. Combining all the variants generated 48 data points which form the basis of the analysis below (2 capacities (I & II) x 2 dates x 3 lengths x 4 contexts = 48 data points).

Table 4-1 Variations to be costed

Parameter	Variants		
Installation date	2020 2040		
Capacity (Nm^3/day) / pipe diameter / compressor capacity	Capacity I: 32,000 / 64,000 / 128,000 Nm^3/day	MP pipe of 6" diameter (max. capacity 300,000Nm^3/day) – same pipe diameter used for all capacities	Compressor-storage (170,000 Nm^3/day)
	Capacity II: 16,000 Nm^3/day	LP pipe of 12" (max. capacity 20,000 Nm^3/day)	Compressor-storage (42,500 Nm^3/day)
Length	1km – single compressor-storage 5km – single compressor-storage 15km – single compressor-storage		
Context	Rural Semi-urban Urban London		
Mode	New build		

4.2 Results and Analysis

The outputs from the ICC for the different scenarios are shown in Table 4-2. As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project. Also included in the table is NPV/km. This is discussed in Section 4.2.2 below.

The NPV (Capex and Opex) of all scenarios are shown graphically in Figure 4-2 and Figure 4-3.

Table 4-2 Base output data

Installation date	Context	Capacity	Length (km)	First Cost (£m)	NPV Capex (£m)	NPV Opex (£m)	NPV Total (£m)	NPV/km (£m/km)
2020	Rural	LP	1km	3.19	6.59	0.75	7.34	7.34
			5km	11.91	18.03	2.92	20.95	4.19
			15km	33.06	45.73	8.19	53.92	3.59
	Semi-urban		1km	3.74	7.36	0.89	8.25	8.25
			5km	14.59	22.72	3.58	26.29	5.26
			15km	40.97	59.96	10.12	70.08	4.67
	Urban		1km	7.92	15.11	1.93	17.04	17.04
			5km	35.42	54.93	8.79	63.72	12.74
			15km	102.83	152.40	25.60	178.00	11.87
	London		1km	9.67	18.43	2.36	20.79	20.79
			5km	43.21	67.01	10.73	77.74	15.55
			15km	125.45	185.90	31.24	217.14	14.48
	Rural	MP	1km	3.47	7.48	0.78	8.27	8.27
			5km	10.31	16.41	2.49	18.89	3.78
			15km	26.56	37.70	6.53	44.23	2.95
	Semi-urban		1km	3.93	7.97	0.89	8.86	8.86
			5km	12.58	20.12	3.04	23.16	4.63
			15km	33.22	49.26	8.16	57.42	3.83
	Urban		1km	7.62	15.48	1.82	17.29	17.29
			5km	30.98	49.17	7.64	56.81	11.36
			15km	87.85	131.29	21.83	153.11	10.21
	London		1km	9.29	18.88	2.22	21.10	21.10
			5km	37.79	59.98	9.32	69.30	13.86
			15km	107.17	160.15	26.63	186.78	12.45
2040	Rural	LP	1km	5.56	3.97	0.44	4.42	4.42

Installation date	Context	Capacity	Length (km)	First Cost (£m)	NPV Capex (£m)	NPV Opex (£m)	NPV Total (£m)	NPV/km (£m/km)
			5km	21.40	11.05	1.73	12.78	2.56
			15km	59.85	28.25	4.84	33.09	2.21
	Semi-urban		1km	6.56	4.67	0.52	5.19	5.19
			5km	26.24	13.55	2.11	15.66	3.13
			15km	74.12	35.14	5.98	41.12	2.74
	Urban		1km	14.19	8.25	1.14	9.39	9.39
			5km	64.29	30.80	5.21	36.01	7.20
			15km	187.11	86.09	15.16	101.25	6.75
	London		1km	17.31	10.06	1.40	11.45	11.45
			5km	78.43	37.57	6.35	43.92	8.78
			15km	228.27	105.01	18.50	123.51	8.23
	Rural	MP	1km	5.84	4.56	0.46	5.02	5.02
			5km	18.27	10.12	1.47	11.59	2.32
			15km	47.85	23.36	3.86	27.22	1.81
	Semi-urban		1km	6.66	5.26	0.53	5.78	5.78
			5km	22.36	12.34	1.79	14.14	2.83
			15km	59.87	29.28	4.82	34.10	2.27
	Urban		1km	13.39	8.48	1.07	9.55	9.55
			5km	55.97	27.64	4.52	32.17	6.43
			15km	159.64	74.32	12.93	87.24	5.82
	London		1km	16.34	10.34	1.31	11.65	11.65
			5km	68.28	33.72	5.52	39.24	7.85
			15km	194.75	90.65	15.77	106.42	7.09

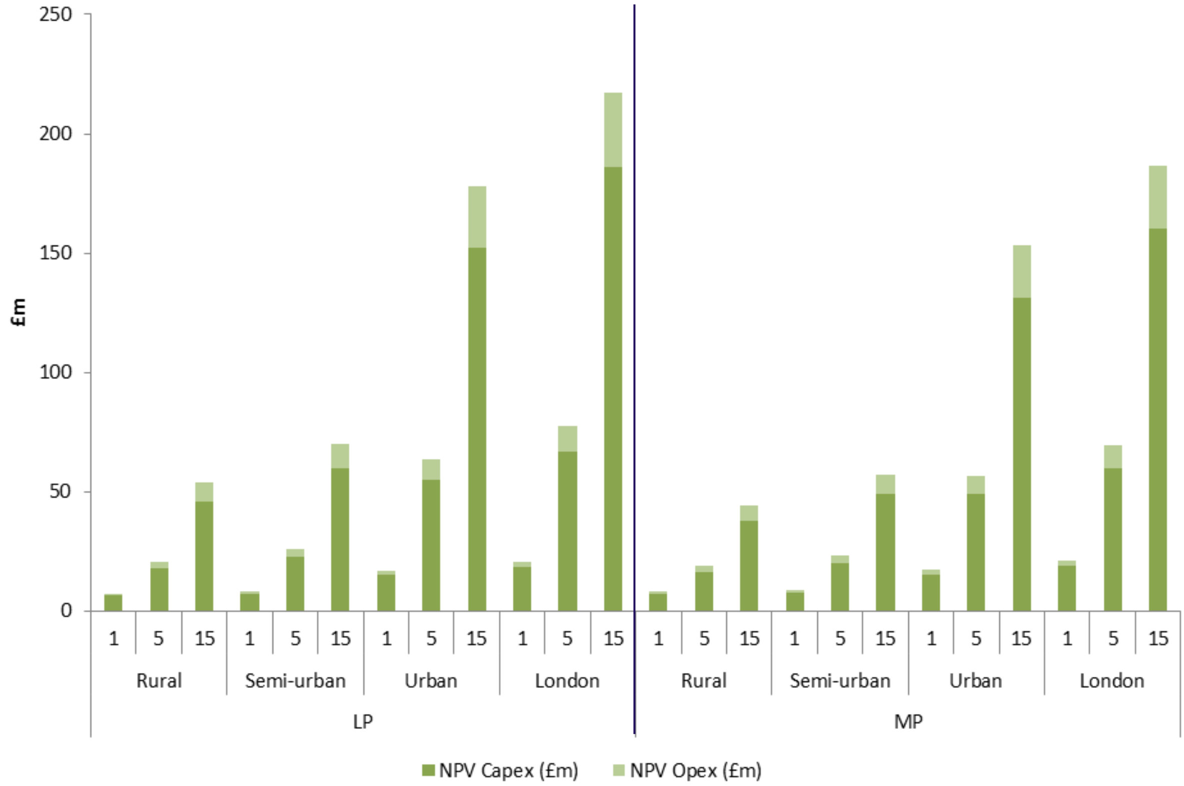


Figure 4-2 NPV (Capex and Opex) 2020

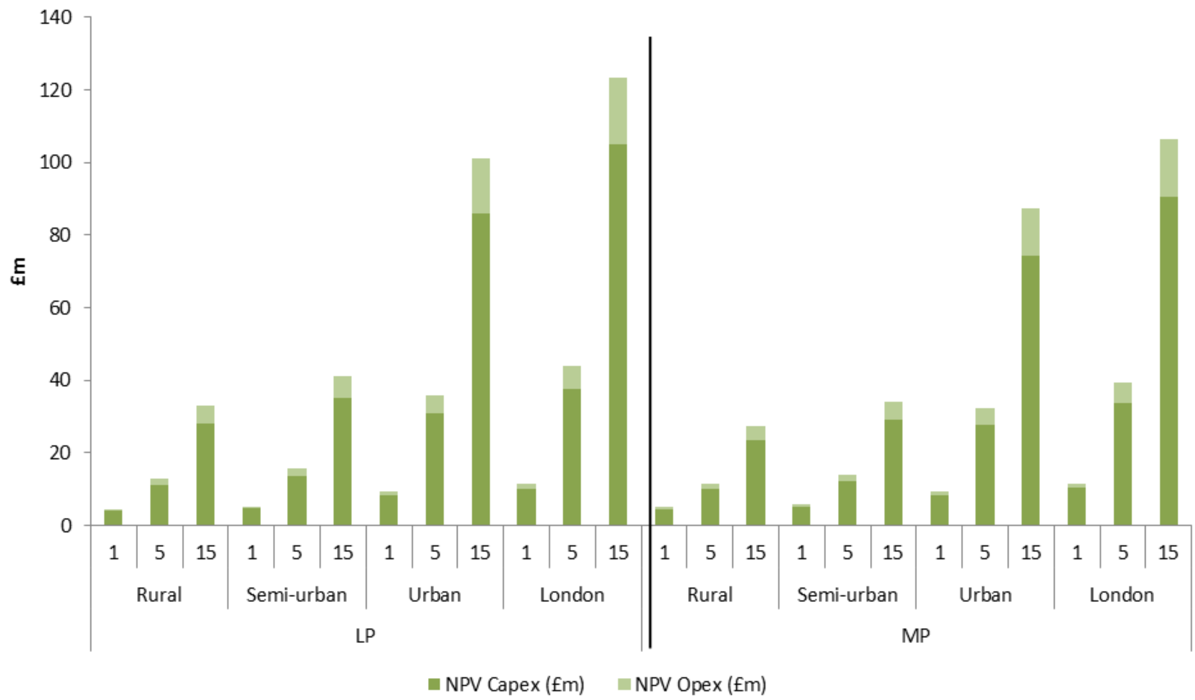


Figure 4-3 NPV (Capex and Opex) 2040

Key findings:

- NPV Total is higher for all network lengths in the denser or more populated areas. Costs differ by a factor of around 1.25 from rural to semi-urban but around 3-4 from rural to urban and London. This is due to higher installation costs (and Repex) in denser contexts.
- A larger increase in cost occurs in an urban context with longer pipe lengths than a rural context. As the pipe length increases the share of costs represented by pipework increases – pipework installation is more sensitive to context and has a bigger impact at the longer network lengths.
- The longer the pipeline the greater NPV total. The proportion of NPV Opex in the total cost increases with the pipe length.
- The Low Pressure (LP) network costs are higher than the Medium Pressure (MP) network costs due to the pipe sizes selected to cope with the flows required. LP – 12" and MP -6".
- Overall NPV costs are higher in 2020 than 2040.

4.2.1 Analysis: Assemblies

As previously stated, two Assemblies have been used for this task: the distribution gas network (MP and LP) and the compressor/conversion station. Figure 4-4 illustrates the percentage contribution to total cost of the two Assemblies for each variation.

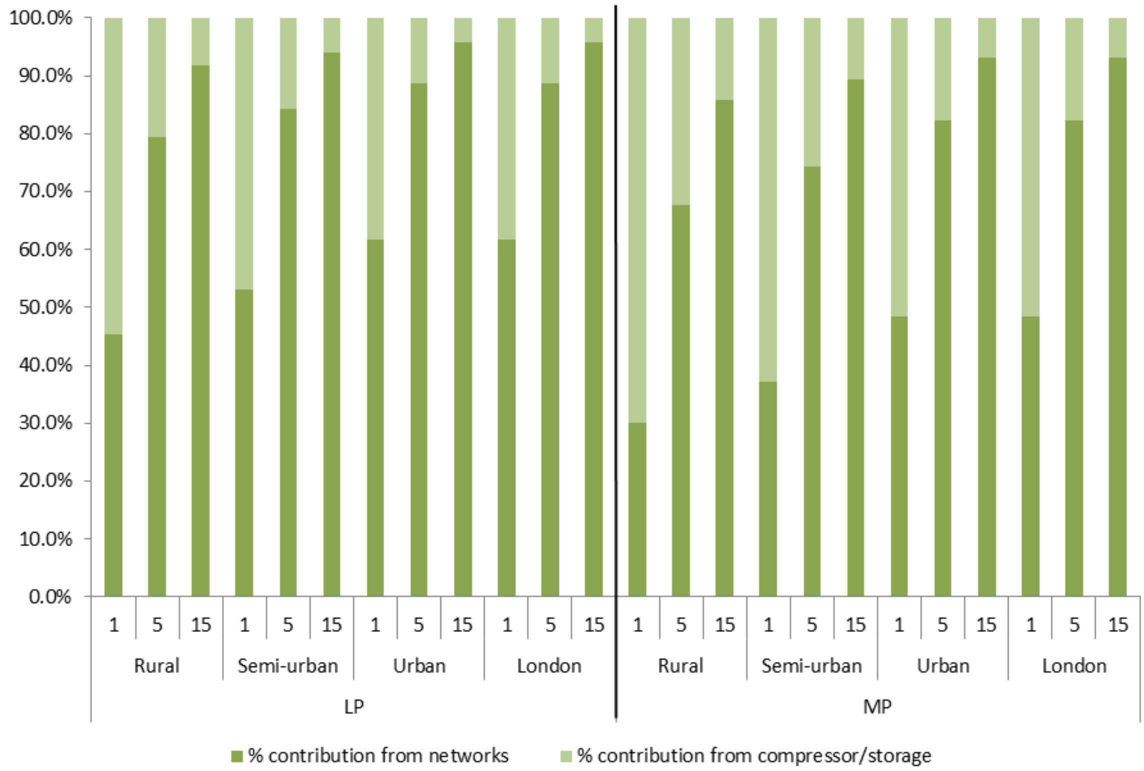


Figure 4-4 Percentage contribution of each Assembly to total cost

Key findings:

- The Assembly making the highest contribution to total cost varies with the pipeline length (1, 5, 15km). As expected, the longer the pipeline the higher the contribution from the pipeline assembly (LP or MP) compared with the compressor/storage assembly.
- The denser or more populated the area, the higher the contribution made by the pipeline assembly compared with the compressor/storage assembly.
- Generally, in MP networks, the pipeline costs make a lower contribution to total cost than the equivalent context and length in LP networks. This is due to the larger pipe size (12" against 6") used for LP.

4.2.2 Analysis: Normalised costs

Normalised costs of NPV per km for each variation as given in Table 4-2 are presented in Figure 4-5 and Figure 4-6.

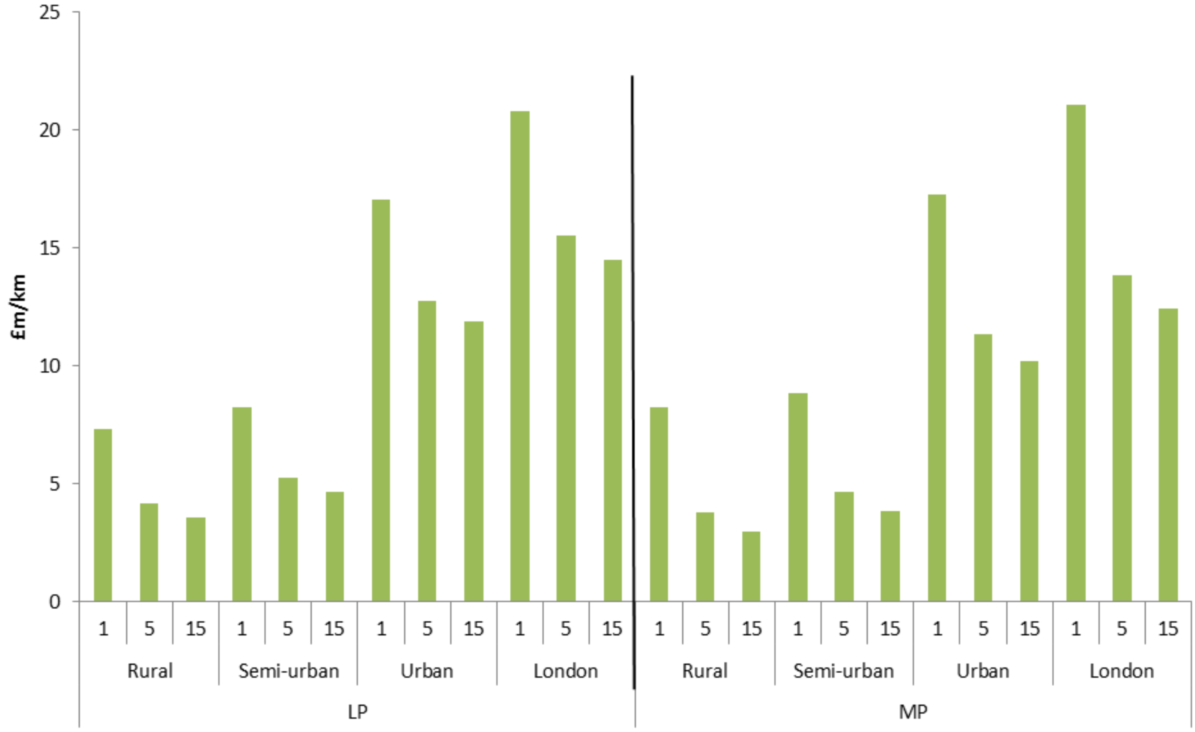


Figure 4-5 NPV total per km 2020

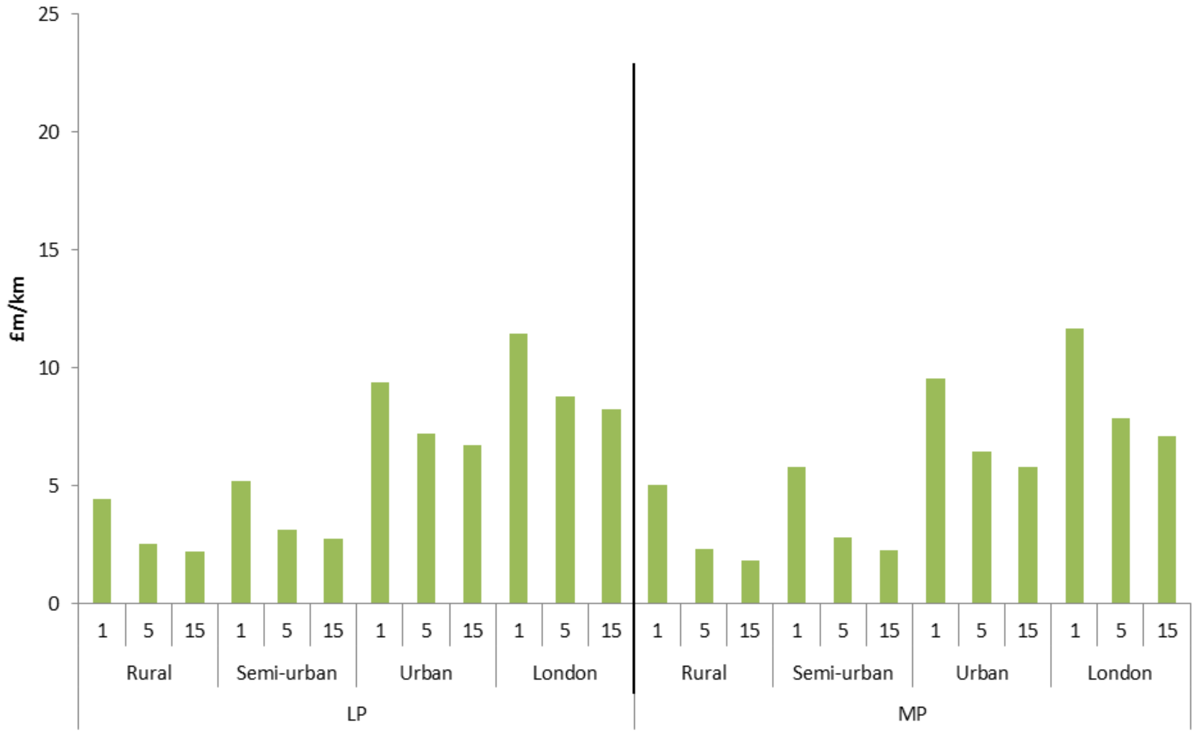


Figure 4-6 NPV total per km 2040

Key findings:

- There is a reduction in cost per km for each additional km of piping. This reduction is more significant from 1 to 5km than from 5 to 15km due to the spreading of the cost of the compressor over the network length (there is only one compressor for each network irrespective of network length).
- As previously stated, context influences cost. Installation costs increase moving from less dense rural areas to increasingly dense semi-urban and urban areas. There is a further uplift in cost in London areas (the ICC applies a 22% uplift in London compared with the UK overall – Section 3.2.3).
- Overall NPV costs are higher in 2020 than 2040.

4.3 Limitations and further work

The limitations impacting the cost analysis include:

- The cost analysis does not include losses which would impact on whole life costs. However, losses would be minimal in new build infrastructure.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in the first version of the ICC used for this study. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in future versions which could impact on these results.

5 G-G-3 Generic decommissioning costs (transmission)

5.1 Research question overview and scope

This research question was concerned with the cost of decommissioning gas transmission networks (NTS) in rural areas.

The schematic in Figure 5-1 shows the boundary, assemblies and network layout of this project. The network comprises transmission pipelines at NTS level (100km in length) and a gas regulator at the interface between the NTS and LTS gas system (single unit per 100km pipe). The scope excludes the gas compressor between the gas terminal and the NTS system or compressors along the pipeline length which would be required for longer lengths. In the context of the ICC, the Assemblies used to build the network are:

- Conversion – NTS. Conversion NTS/HP [10,000,000 m^3/day]
- Transmission: NTS: Buried: 28" gas pipe - [20,000,000 m^3/day]
- Transmission: NTS: Buried: 32" gas pipe - [25,000,000 m^3/day]
- Transmission: NTS: Buried: 34" gas pipe - [30,000,000 m^3/day]

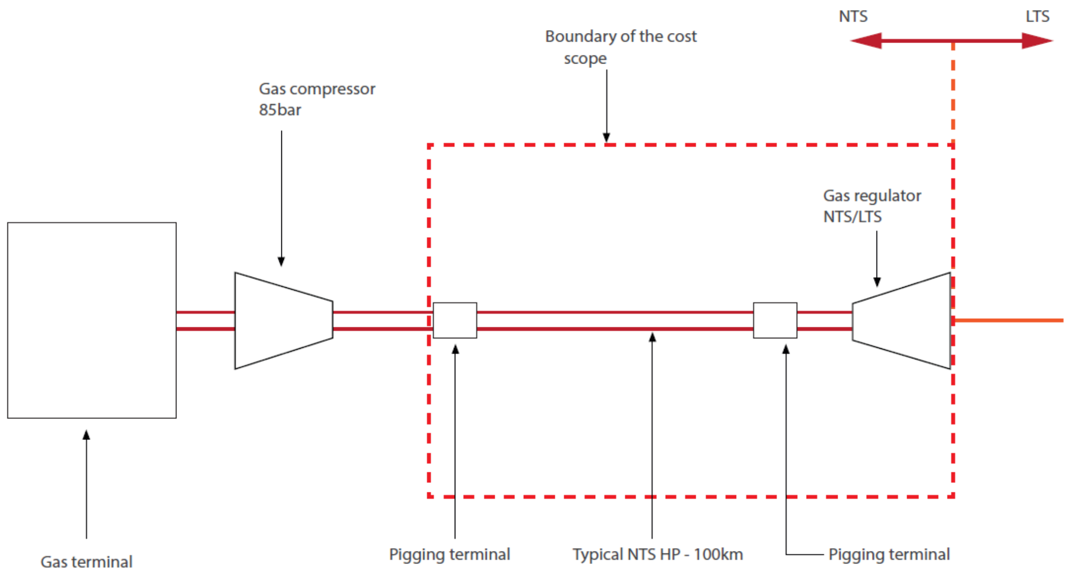


Figure 5-1 Network schematic indicating scope boundary

The research question was concerned with exploring costs for different pipe capacities decommissioned at different dates. The variants are summarised in Table 5-1. Combining all the variants generated 6 data points which form the basis of the analysis below. For the decommissioning of gas transmission networks the ICC tool includes:

- Calliper PIG / clean pipeline inspection
- Cap and abandon NTS pipeline

- Remove NTS PIG
- Remove NTS valve
- Remove NTS to LTS Pressure reduction station

Table 5-1 Variations to be costed

Parameter	Variants	Application / notes
Decommissioning date	2020 2050	Each date to be applied to each capacity
Capacity / pipe diameter	20m m^3/day - 28” 25m m^3/day - 32” 30m m^3/day - 34”	Each capacity to be applied to each date
Length	100km	Same for all variants. Network includes pipe of specified length plus a single compressor/gas regulator
Context	Rural	Same for all variants

5.2 Results and Analysis

The outputs from the ICC for the different scenarios are shown in Table 5-2. In the context of this project, first costs are the decommissioning costs (identified as the abandonment cost in the ICC), and NPV Capex is the discounted decommissioning cost. Opex is not considered for this project.

Table 5-2 Base output data

Installation date	Context	Capacity / Pipe diameter	Length (km)	NPV Capex (£m/100km)	First cost (decommissioning costs) £m/100km
2020	Rural	20m m^3/day - 28”	100	8.9	10.5
	Rural	25m m^3/day - 32”	100	9.2	10.9
	Rural	30m m^3/day - 34”	100	9.3	11.0
2050	Rural	20m m^3/day - 28”	100	6.7	19.0
	Rural	25m m^3/day - 32”	100	7.0	19.7
	Rural	30m m^3/day - 34”	100	7.1	20.0

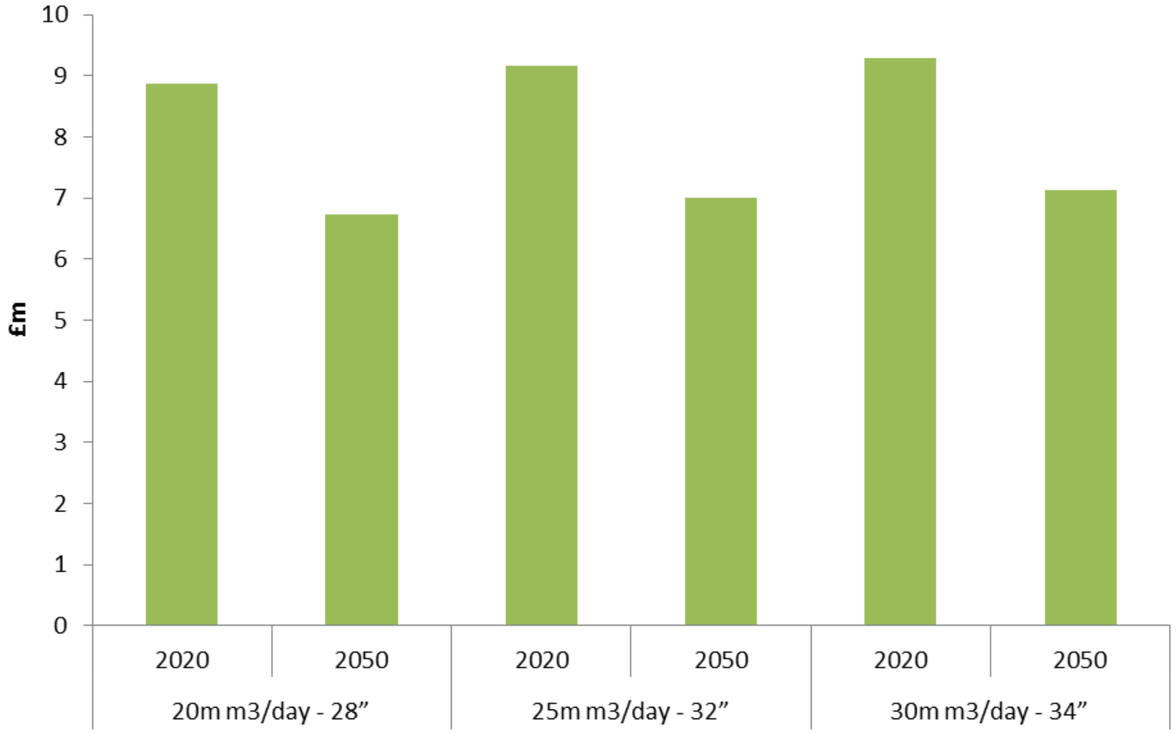


Figure 5-2 NPV Capex

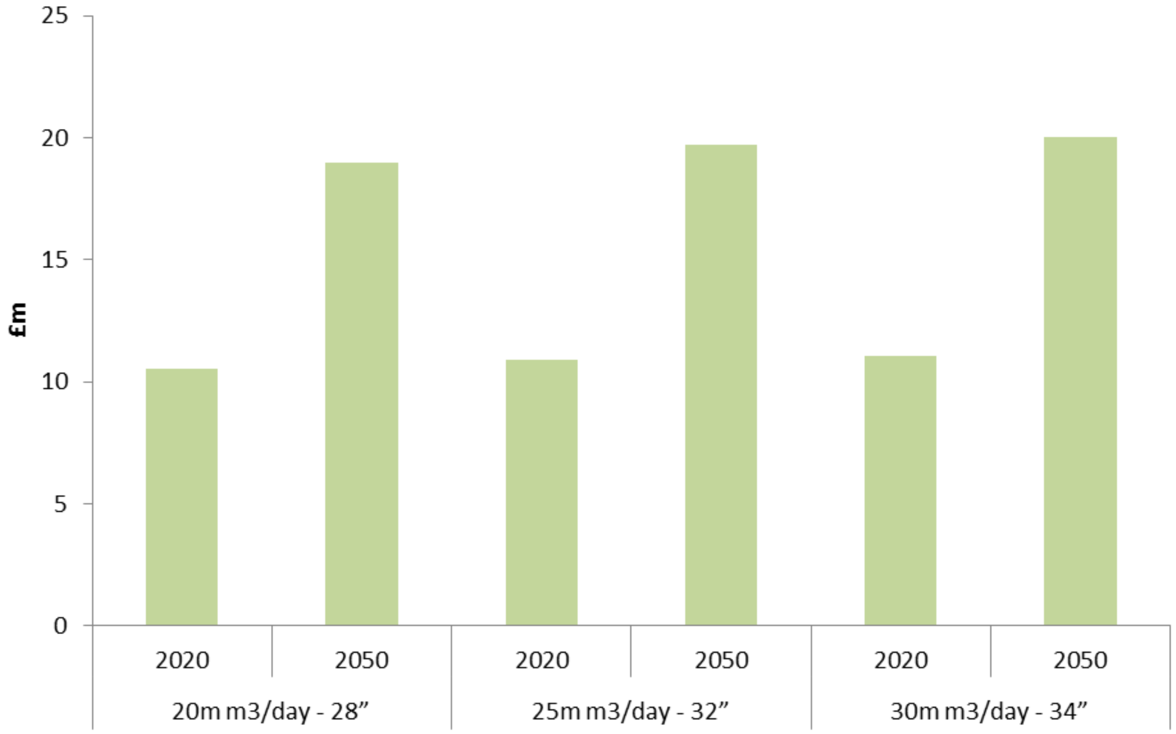


Figure 5-3 First costs

Key findings:

- Decommissioning costs (first costs) increase slightly with the pipe size although the effect is not marked.
- Based on the indexation included in the ICC, decommissioning costs (first costs) roughly double between 2020 and 2050 from around £10m per 100km to £20m per 100km.
- Decommissioning costs discounted to 2015 are around £9m per 100km for decommissioning in 2020 and around £7m per 100km for decommissioning in 2050.

5.2.1 Analysis: Assemblies

As noted, the network comprises two primary Assemblies, 100km of transmission NTS pipeline and a conversion station (NTS/LTS). Figure 5-4 shows the percentage contribution to total costs for these two Assemblies.

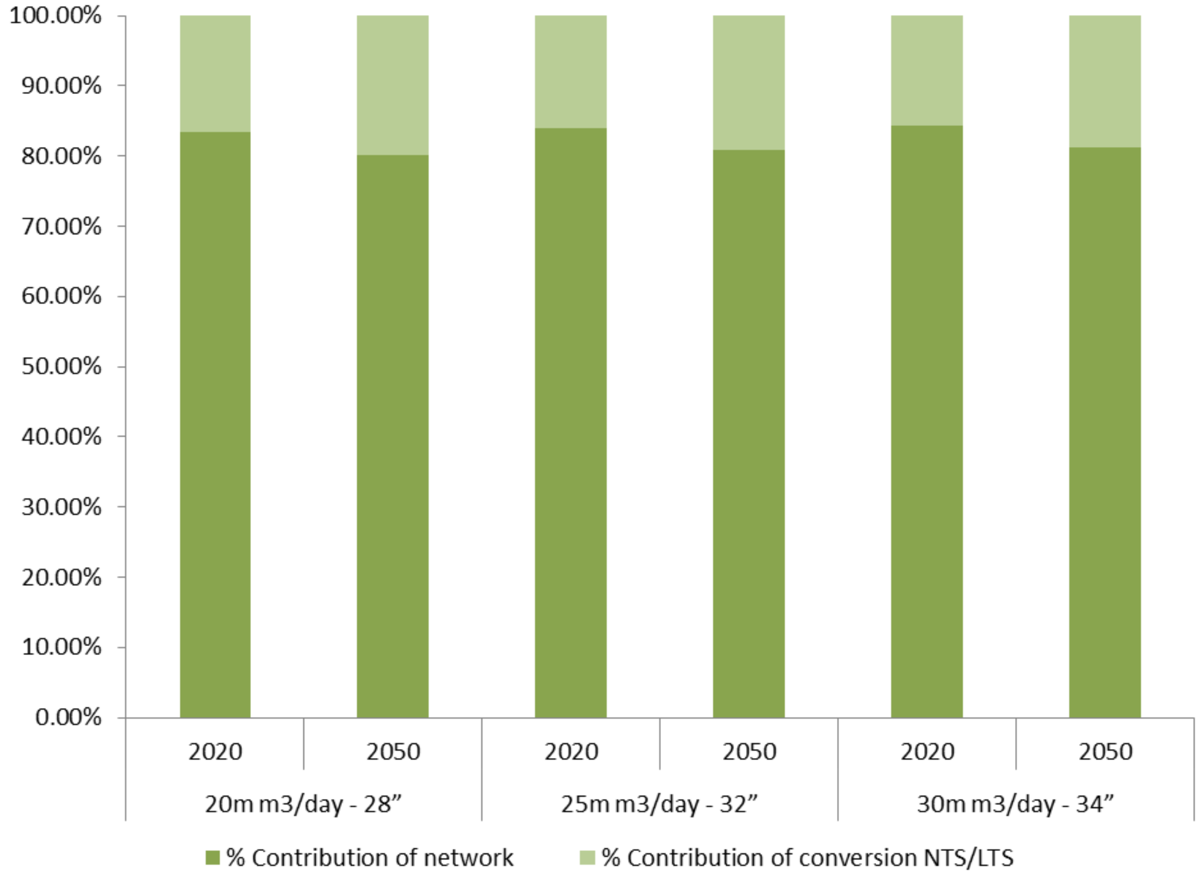


Figure 5-4 Percentage contribution of each Assembly to total cost

Key findings:

- Decommissioning of the pipeline represents around 80-85% of the total cost against 15-20% for decommissioning the conversion station depending on the variation.

5.2.2 Analysis: Normalised costs

All costs in Table 5-2 are per 100km of pipe length; no further normalisation costs have been calculated.

5.3 Limitations and further work

The limitations impacting the cost analysis include:

- The cost analysis does not include losses which would impact the lifecycle costs.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in first version of the ICC. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in the second version of the tool which could impact on these results.

6 G-G-4 Generic decommissioning costs (distribution)

6.1 Research question overview and scope

This research question was concerned with the cost of full decommissioning of natural gas distribution networks in rural, semi-urban, urban and London areas. The scope was focused on:

- Population < 1,000 – rural – IP/LP on a single network e.g. village / small town
- Population 7,500 – semi-rural - MP/LP
- Population 20,000 - urban (fed from city gate PRS but in city centre) - IP/MP/LP
- Population 50,000 - London (fed from city gate PRS but in city centre) - IP/MP/LP

The schematic in Figure 6-1 shows the boundary, assemblies and network layout of this project. Essentially it comprises the gas distribution networks including domestic and non-domestic connections as well as pressure reduction stations where required.

6.1.1 Design of representative network

The network design was based on current conventions in relation to pressures, pipe materials, sizes and connections. To devise a representative network model over different populations and population densities, spatial analysis was undertaken in GIS for selected areas in the UK[7].

In the context of the ICC, the Assemblies used to build the network are:

- Connection: LP: Buried: 12" Commercial office connection [350 m^3/day]
- Connection: LP: Buried: 2" Residential connection [6 m^3/hr]
- Conversion: IP: None: Conversion IP/MP [30,000 m^3/hr]
- Conversion: MP: None: Conversion MP/LP [5,000 m^3/hr]
- Distribution: IP: Buried: 8" gas pipe urban [400,000 m^3/day]
- Distribution: LP: Buried: 12" gas pipe rural [5,000 m^3/day]
- Distribution: LP: Buried: 12" gas pipe urban [2,0000 m^3/day]
- Distribution: MP: Buried: 6" gas pipeline urban [30,0000 m^3/day]

[7] This is described in full in the Detailed Scoping document available separately from the ETI.

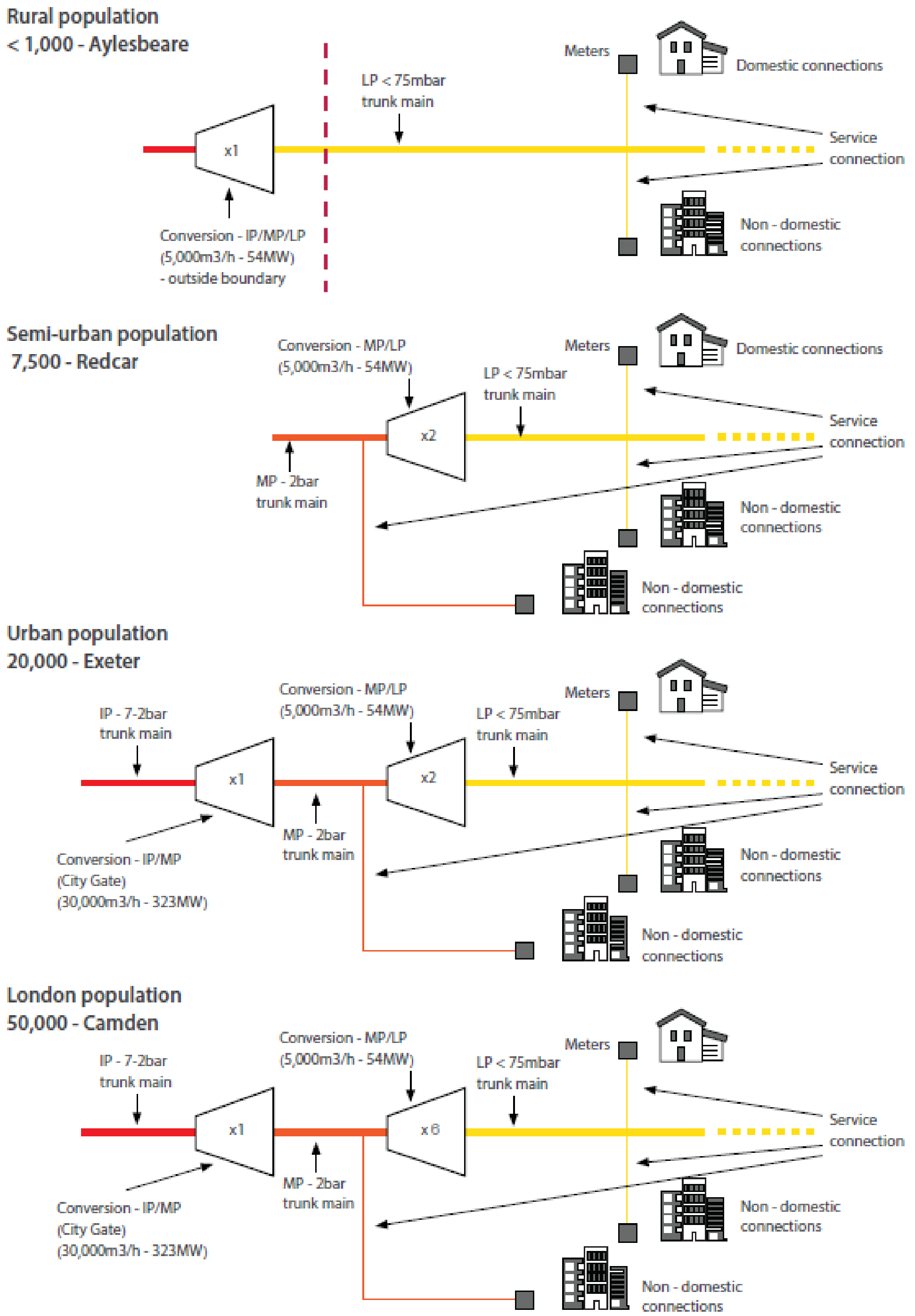


Figure 6-1 Network schematic indicating scope boundary

The research question was concerned with exploring costs in different contexts and capacities as shown in Table 6-1.

Based on the spatial and other analyses, Table 6-1 shows the number of connections, pressure reduction stations and network lengths assumed for each of the different contexts and populations. These four scenarios were costed at two decommissioning dates, 2020 and 2050. Combining all the variants generated 8 data points which form the basis of the analysis below.

Table 6-1 Bill of quantities for the four contexts

<table>
<tr><th rowspan="2">Context</th><th rowspan="2">Population</th><th rowspan="2">Example Area</th><th rowspan="2">Decommissioning date</th><th colspan="2">No. connections</th><th colspan="2">Pressure reduction stations</th><th colspan="3">Network length (km)</th></tr>
<tr><th>Domestic</th><th>Non - domestic</th><th>IP/MP</th><th>MP/LP</th><th>IP</th><th>MP</th><th>LP</th></tr>
<tr><td>Rural</td><td><1,000</td><td>Aylesbeare</td><td>2020
2050</td><td>165</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>3.2</td></tr>
<tr><td>Semi-urban</td><td>7,500</td><td>Redcar</td><td>2020
2050</td><td>2,723</td><td>13</td><td>0</td><td>2</td><td>0</td><td>4</td><td>26.8</td></tr>
<tr><td>Urban</td><td>20,000</td><td>Exeter</td><td>2020
2050</td><td>9,239</td><td>59</td><td>1</td><td>2</td><td>0.7</td><td>9.9</td><td>66</td></tr>
<tr><td>London</td><td>50,000</td><td>Camden</td><td>2020
2050</td><td>22,725</td><td>397</td><td>1</td><td>6</td><td>9.4</td><td>33</td><td>94.4</td></tr>
</table>

Note: Projects with rural contexts have no pressure reduction stations.

6.2 Results and analysis

The outputs from the ICC for the different scenarios are shown in Table 6-2 and graphically in Figure 5-2 and Figure 5-3. In the context of this project, first costs are the decommissioning costs (identified as the abandonment cost in the ICC), and NPV Capex is the discounted decommissioning cost. Opex is not considered for this project.

Table 6-2 Base output data

Decommissioning date	Context	Population	First Cost (£m)	NPV Capex (£m)
2020	Rural	<1,000	0.25	0.21
2050	Rural	<1,000	0.49	0.17
2020	Semi-urban	7,500	4.42	3.72
2050	Semi-urban	7,500	8.55	3.04
2020	Urban	20,000	14.39	12.12
2050	Urban	20,000	27.94	9.93
2020	London	50,000	39.09	32.91
2050	London	50,000	75.75	26.92

Figure 6-2 NPV Capex

Figure 6-3 First costs

Key findings:

- The more densely populated the context the higher the NPV Capex and the first costs due to the larger scale of system being decommissioned, i.e. longer pipe networks, more pressure reduction stations etc.
- NPV Capex costs are higher in 2020 than 2050 due to effects of discounting. However, undiscounted first costs are lower in 2020 than 2050 as the costs in later years are subject to indexation.

6.2.1 Analysis: Assemblies

The contribution of the different Assemblies to the Capex and Repex cash flow is shown in Figure 6-4. The Assemblies are shown by context for ease of comparison. Assembly costs are shown for a 2020 decommissioning date only – the split of assembly costs with a 2050 decommissioning date are similar. 'Other' costs are made up of a mixture of connection, distribution and conversion Assemblies but are too low to feature in the top 5 list.

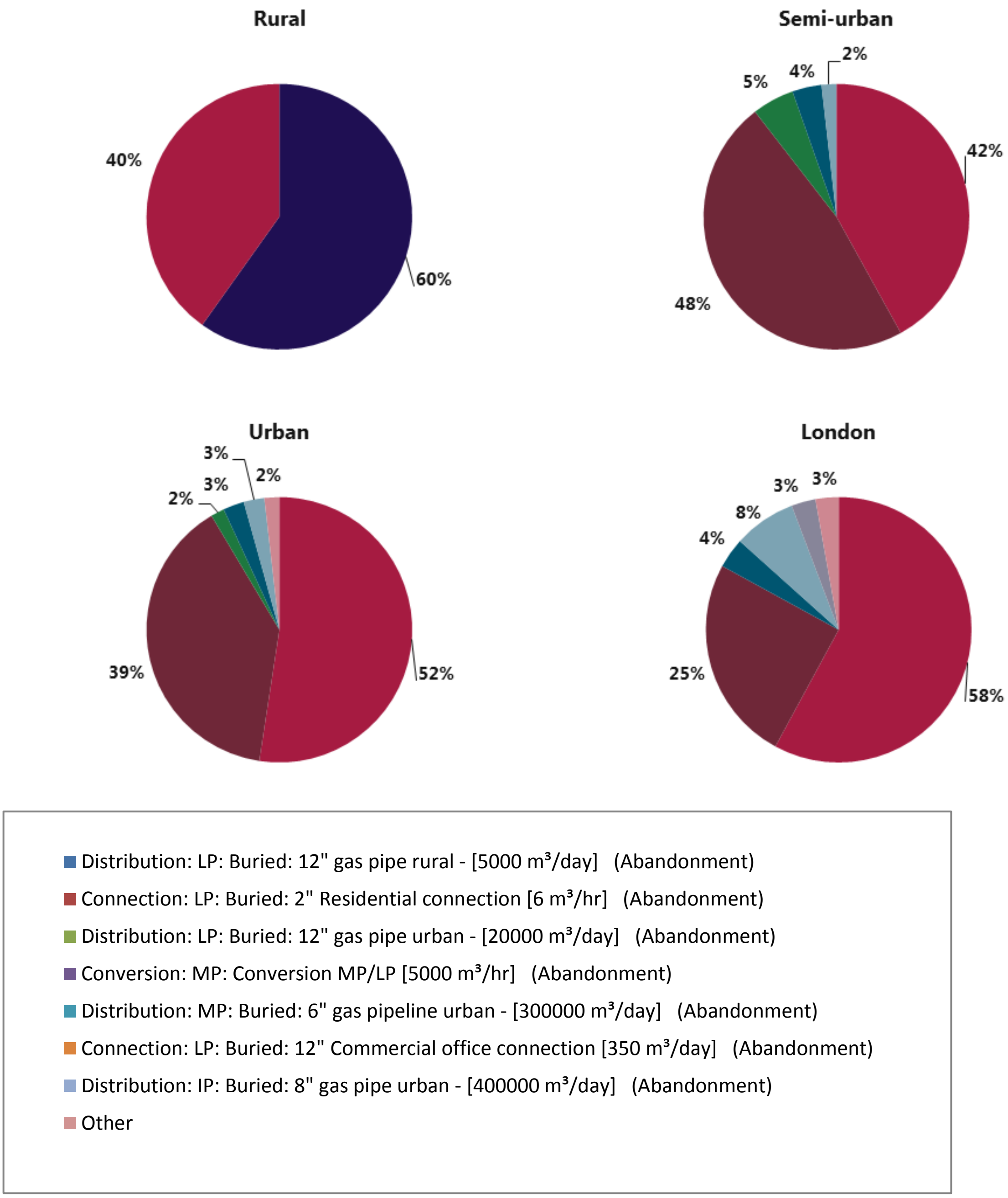


Figure 6-4 Contribution of assembly costs to each variation (with 2020 decommissioning date)

Key findings:

- The cost break down for the different contexts shown in Figure 6-4 is highly dependent on the network spatial GIS analysis and hence on the quantities of the different Assemblies required. As per the analysis above, the number of LP connections and LP network length represent key factors in the decommissioning costs.

- For rural contexts, 60% of the total costs are derived from decommissioning the LP network and 40% from decommissioning the domestic connections.
- For semi-urban contexts, 48% of the total costs are derived from decommissioning the LP network and 42% from decommissioning the domestic connections. These are followed by 5% from the gas pressure reduction stations and 4% and 2% from the MP network and commercial connections respectively.
- For urban contexts, 52% of the total costs are derived from decommissioning the domestic connections, while 39% is from the decommission of the LP network, followed by the gas pressure reduction stations, the MP network, commercial connections and other costs at approximately 2-3% for each item.
- For London contexts 58% of the total costs are derived from the domestic connections, while 25% is from the decommission of the LP network, followed by the commercial connections (8%), MP network (4%), IP network (3%) and others (3%).

6.2.2 Analysis: Normalised costs

Normalised costs are presented in Figure 6-5 and Figure 6-6 as NPV Capex per connection and NPV Capex per km. Connections include both domestic and non-domestic – the latter represents a small contribution of costs on a per connection basis due to the relative number of domestic and non-domestic properties.

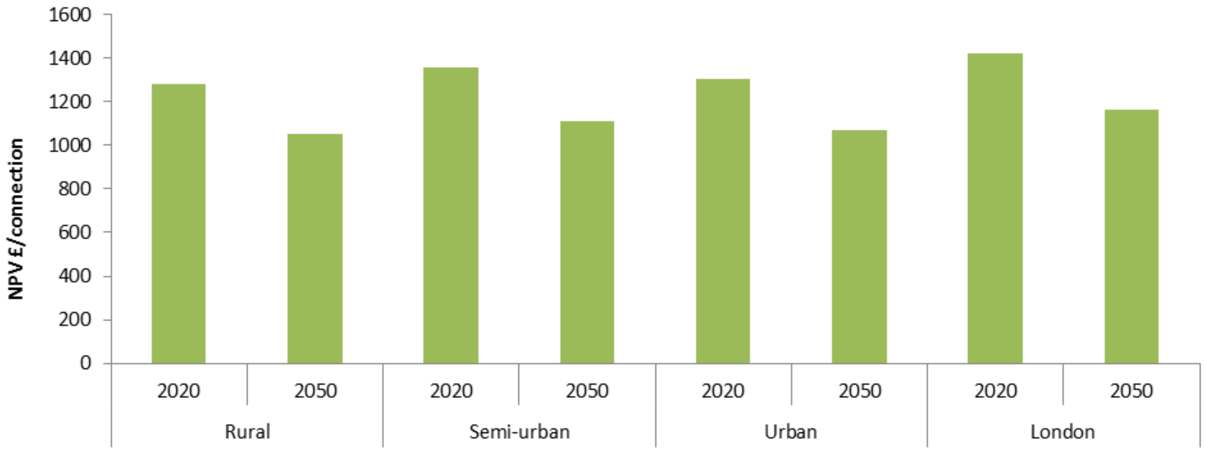


Figure 6-5 NPV Capex per connection

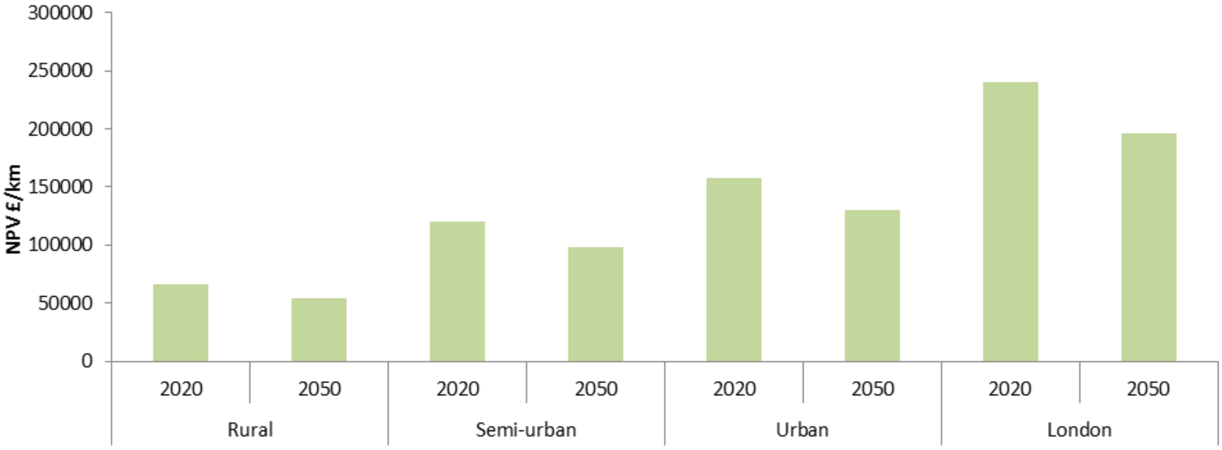


Figure 6-6 NPV Capex per km

Key findings:

- Decommissioning costs of gas distribution network per connection increases with denser contexts with the exception of urban which has very similar cost to semi-urban, this is due to number of connections calculated during the spatial GIS analysis.
- Decommissioning cost of gas distribution network per km basis is significantly higher as context moves from rural to urban. Costs in London are the highest due to the regional uplift applied (see Section 3.2.5).
- NPV Capex is lower for the 2050 installation date compared with 2020 due to impact of discounting.

6.3 Limitations and further work

The limitations impacting the cost analysis include:

- As the modelling approach has been based on using the road network as a proxy for gas network length there will be some errors arising from this. Changes in network length would affect costs.
- The cost analysis does not include losses which would impact on whole life costs.
- In the cost database only a single size for the pressure reduction station (PRS) is available, therefore the PRS cost would be overstated in the rural and semi-urban areas when they are oversized vs. demand.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in first version of the ICC. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in the second version of the tool which could impact on these results.

7 G-G-5 Generic operational costs associated with partially decommissioned network (distribution)

7.1 Research question overview and scope

The research question was concerned with operational costs associated with the retained part of a partially decommissioned network at distribution level in rural, semi-urban, urban and London areas. The scope was focused on:

- Population < 1,000 – rural – IP/LP on a single network e.g. village / small town
- Population 7,500 – semi-rural - MP/LP
- Population 20,000 - urban (fed from city gate PRS but in city centre) - IP/MP/LP
- Population 50,000 - London (fed from city gate PRS but in city centre) - IP/MP/LP

The schematic in Figure 7-1 shows the boundary, assemblies and network layout of this project. Essentially it is comprised of the gas distribution networks including domestic and non-domestic connections as well as pressure reduction stations where required.

The decommissioning process was backwards from the customer metres to the gas main starting from the service connection and moving to the gas trunk main (LP, MP and IP). The decommissioning process assumes:

- HP/IP: Pig and clean pipework and purge hydrocarbons. Remove pig stations, line valves and AGIs, cap pipework and fill with grout in urban areas and at crossings, otherwise fill with air or nitrogen and cap. For steel (IP) pipes then cathodic control should be maintained to ensure corrosion of the pipe does not have an environmental impact in the area.
- MP/LP: Remove line valves, clean as required, cap pipework and fill with grout in urban areas, under roads and at crossings, otherwise fill with air or nitrogen and cap.
- Pressure reduction stations: Clean residues, remove equipment for scrap, resale or reuse, cap and seal below ground pipework, demolish and remove housings, remove foundations and remediate soil to depth of 1m.
- Connections: Cap service pipe, remove meter and valves, remove housing.

7.1.1 Design of representative network

The network design was based on current conventions in relation to pressures, pipe materials, sizes and connections. To devise a representative network model over different populations and population densities, spatial analysis was undertaken in GIS for selected areas in the.

In the context of the ICC, the Assemblies used to build the network are:

- Connection: LP: Buried: 12" Commercial office connection [350 m3/day]
- Connection: LP: Buried: 2" Residential connection [6 m3/hr]
- Conversion: IP: None: Conversion IP/MP [30,000 m^3/hr]

- Conversion: MP: None: Conversion MP/LP [5,000 m^3/hr]
- Distribution: IP: Buried: 8" gas pipe urban [400,000 m^3/day]
- Distribution: LP: Buried: 12" gas pipe rural [5,000 m3/day]
- Distribution: LP: Buried: 12" gas pipe urban [2,0000 m^3/day]
- Distribution: MP: Buried: 6" gas pipeline urban [30,0000 m^3/day]

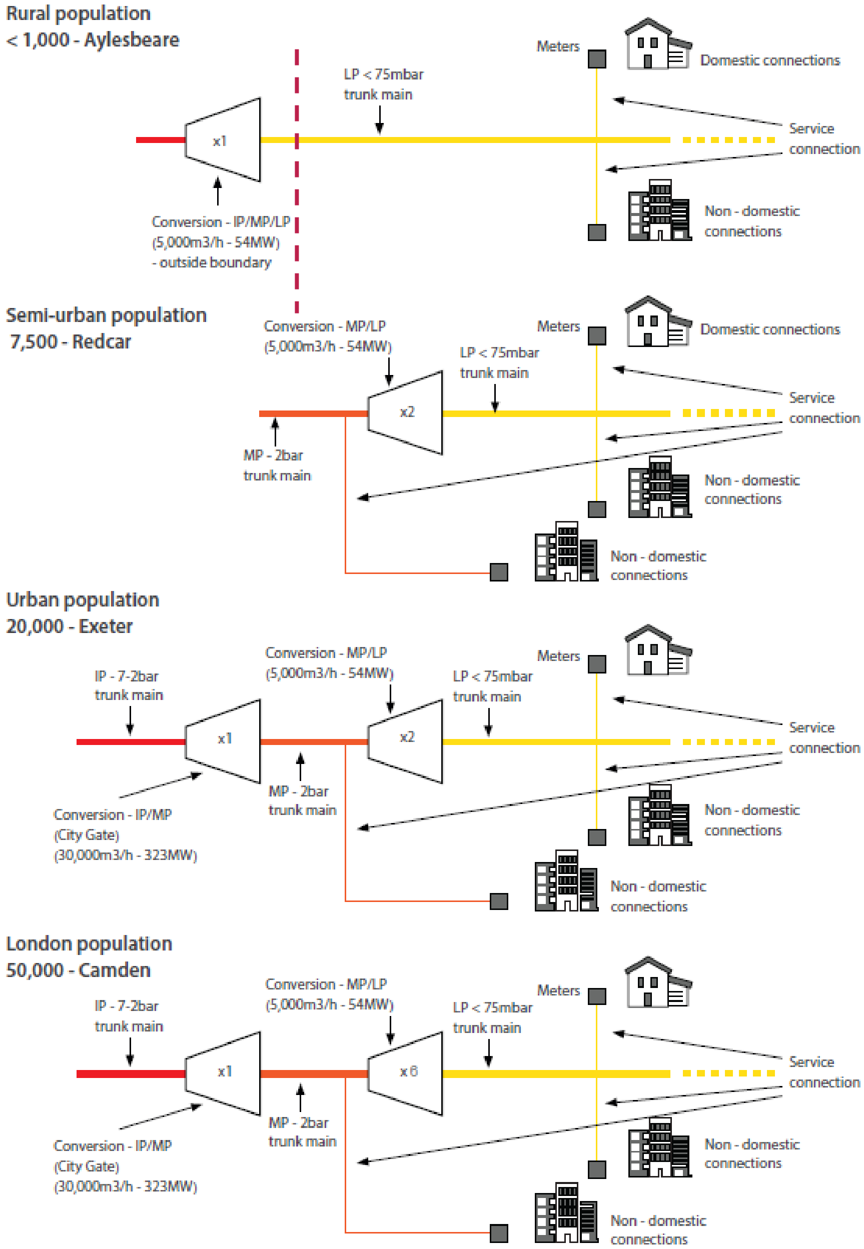


Figure 7-1 Network schematic indicating scope boundary

The research question was concerned with exploring costs in different contexts and capacities as shown in Table 7-1.

Based on the spatial and other analyses, Table 7-1 shows the number of connections, pressure reduction stations and network lengths assumed for each of the different contexts and populations.

These four scenarios were costed at two decommissioning dates, 2020 and 2040 and with three different decommissioning rates, 5%, 25% and 60%. The decommissioning rate is applied equally to all assets in the network.

Combining all the variants generated 24 data points which form the basis of the analysis below.

Table 7-1 Bill of quantities for the four contexts

Context	Population	Decommission-ing date	Decommission-ing rate	No. connections		Pressure reduction stations		Network length (km)		
				Domestic	Non - domestic	IP/MP	MP/LP	IP	MP	LP
Rural	<1,000	2020 2040	5% 25% 60%	165	0	0	0	0	0	3.2
Semi-urban	7,500			2,723	13	0	2	0	4	26.8
Urban	20,000			9,239	59	1	2	0.7	9.9	66
London	50,000			22,725	397	1	6	9.4	33	94.4

Note: Projects with rural contexts have no pressure reduction stations.

7.2 Results and analysis

The outputs for this research question include operational costs and decommissioning (abandonment) costs.

As described in Section 3.3.2, Opex NPV is the discounted Opex cash flows (direct and indirect) for the period 2015 to 2075. It excludes replacement costs (Repex) and losses. A full description of the basis of Opex costs in the ICC is given in Appendix C.

Table 7-2 shows the ICC output cost data for the different variants for decommissioning in 2020 and 2040 (columns A to C) as well as the reduction in Opex of the partially decommissioned network compared with Business as Usual (BAU) (ie. none of the network is decommissioned) (column E).

Figure 7-2 shows these results graphically.

Table 7-2 Base cost data (all in £ millions)

Decommissioning date	% Decommissioned	Context	NPV abandonment costs	NPV Opex remaining network	Total NPV	NPV Opex BAU	NPV Opex saved
			A	*B*	*C=A+B*	*D*	*E=D-B*
2020	5%	London	1.1	236.0	237.1	244.8	8.8
		Urban	0.4	108.5	108.9	112.7	4.2
		Semi-urban	0.1	17.2	17.4	18.0	0.7
		Rural	0.0	1.1	1.1	1.1	0.0
	25%	London	5.6	199.1	204.7	244.8	45.7
		Urban	2.0	91.0	93.0	112.7	21.7
		Semi-urban	0.6	14.3	14.9	18.0	3.6
		Rural	0.0	0.9	0.9	1.1	0.2
	60%	London	13.3	127.7	141.0	244.8	117.0
		Urban	4.9	58.0	62.9	112.7	54.7
		Semi-urban	1.5	9.1	10.6	18.0	8.9
		Rural	0.1	0.6	0.7	1.1	0.5
2040	5%	London	0.9	242.2	243.1	244.8	2.6
		Urban	0.3	111.3	111.6	112.7	1.4
		Semi-urban	0.1	17.7	17.8	18.0	0.2
		Rural	0.0	1.1	1.1	1.1	0.0
	25%	London	4.3	229.5	233.8	244.8	15.3
		Urban	1.6	104.7	106.3	112.7	8.0
		Semi-urban	0.5	16.6	17.1	18.0	1.4
		Rural	0.0	1.1	1.1	1.1	0.0
	60%	London	10.3	197.8	208.1	244.8	47.0
		Urban	3.8	89.8	93.7	112.7	22.8
		Semi-urban	1.2	14.5	15.6	18.0	3.5
		Rural	0.1	1.0	1.1	1	0.1

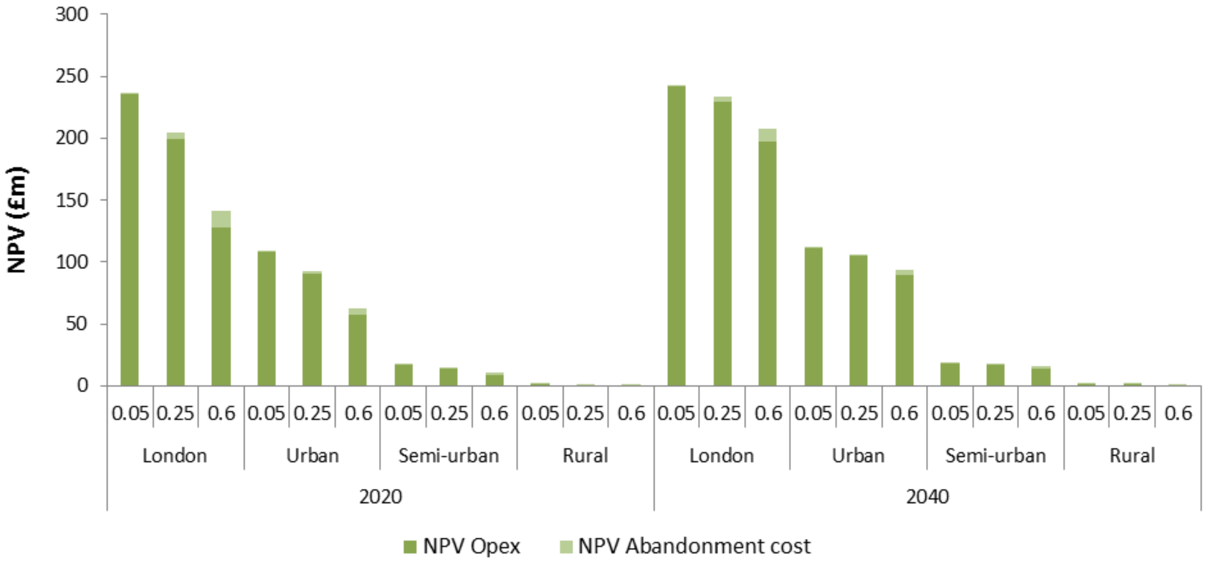


Figure 7-2 NPV (Opex + abandonment) of remaining network at different decommissioning rates in all contexts

Figure 7-3 illustrates the impact of partial decommissioning on annual operating cost cash flows. This example is for decommissioning in 2020 in the London context.

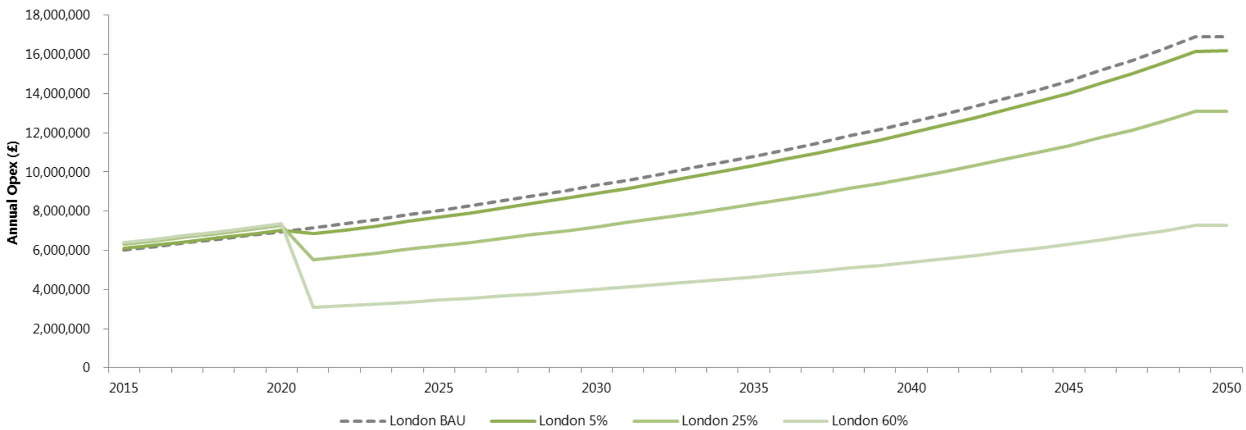


Figure 7-3 Opex cash flows for decommissioned networks in London in 2020

7.2.1 Analysis: Total network costs

The results given in Table 7-2 and Figure 7-2 are for the entire network in each context.

Key findings:

- In each context, reduction in Opex with increasing decommissioning is linear (see also Figure 7-4). This is a reflection of the modelling approach, where both direct and indirect costs are prorated to asset value. A prorated approach is considered a reasonable approximation of the actual situation on the basis that the vast majority (90-95%) of operating costs scale with the extent of the network being managed with over 90% being directly or 'closely associated' with network extent.

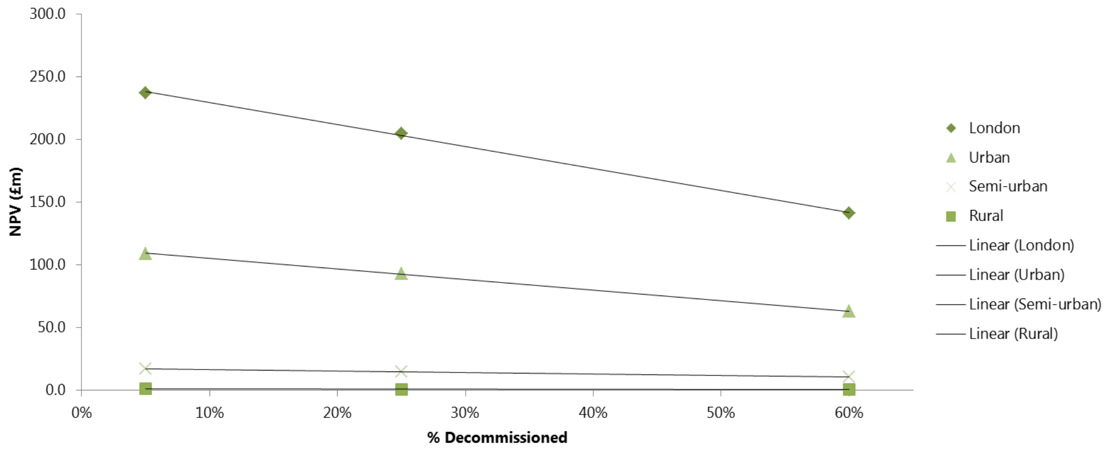


Figure 7-4 Variation of NPV (Opex + abandonment) of remaining network with % decommissioned in different contexts (2020)

- Direct costs represent approximately[8] 80% of the overall Opex for gas distribution infrastructure (see Figure 7-5 for an example of direct / indirect costs in this study). Indirect costs include both closely associated costs[9] and business support costs[10]. No specific breakdown of indirect network operating costs was available for gas distribution, but for electrical distribution around 60-70% of indirect costs fall into the 'closely associated' cost category. If this ratio holds for gas distribution the total proportion of 'business support' cost, is around 6-8% of overall Opex and would itself contain some cost categories linked to a greater or lesser extent to the scale of the network (e.g. insurance costs will be linked to the value of the assets being insured).

[8] The percentage varies by slightly by region, see Appendix C.
[9] Including: Network Design and Engineering; Project Management, Engineering Management and Clerical Support, System Mapping, Operational Training, Vehicles and Transport, Stores and Logistics and Research and Development.
[10] Including: Procurement, HR, Insurance, Finance, audit and regulation, Corporate, IT & Telecoms, Property Management, Non-Operational Training and CEO/corporate costs.

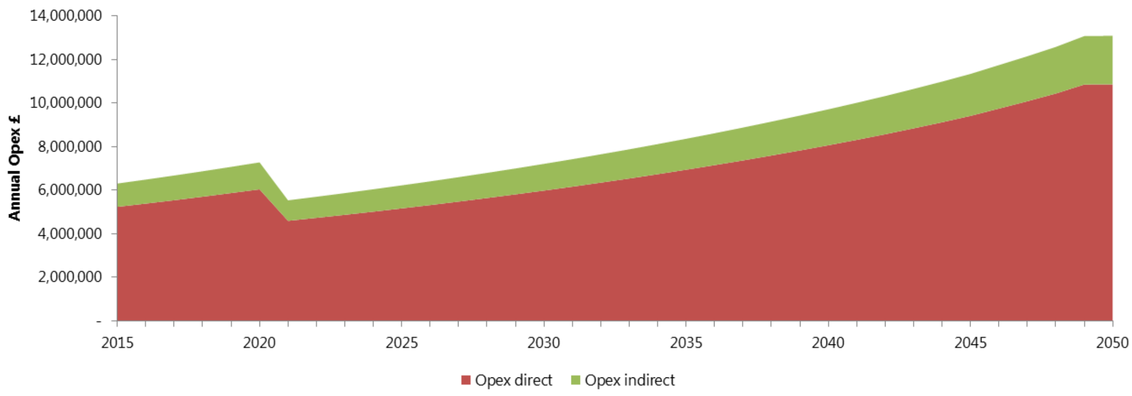


Figure 7-5 Opex (direct and indirect) cash flow in London context with 25% of the network decommissioned in 2020

- Decommissioning (abandonment) costs represent a small percentage of total Opex NPV of the partially decommissioned network, this percentage increasing as more of the network is decommissioned.
- Decommissioning (abandonment) costs represent a higher percentage share of total NPV in semi-urban and rural areas than in urban and London areas. This is a reflection of the modelling approach whereby Opex costs are prorated to asset value and asset value is lower in rural and semi-urban areas due to lower installation costs.
- The NPV of Opex saved (column E of Table 7-2) is 5 to 10 times greater than the abandonment cost (column A of Table 7-2) for networks decommissioned in 2020.
- As would be expected, annual Opex cash flows of the remaining network are reduced when a proportion of it is decommissioned (Figure 7-3).

7.2.2 Analysis: Normalised costs

The costs described above are for entire networks for differing population sizes in differing contexts. These costs have been normalised in relation to the number of connections in each context as outlined in Table 7-3. Operating costs (BAU and partially decommissioned) have been spread over the total number of connections served in the network.

Table 7-3 BAU and decommissioned network cost data per connection served

Decommissioning date	% Decommissioned	Context	Connections (BAU)	BAU NPV Opex / connection £	Connections (remaining post de-commissioning)	NPV Opex partially decommissioned network / connection remaining £
2020	5%	London	22,725	10,771	21,589	10,984
		Urban	9,239	12,198	8,777	12,407
		Semi-urban	2,723	6,593	2,587	6,715
		Rural	165	6,715	157	6,840
	25%	London	22,725	10,771	17,044	11,926
		Urban	9,239	12,198	6,929	13,354
		Semi-urban	2,723	6,593	2,042	7,234
		Rural	165	6,715	124	7,434
	60%	London	22,725	10,771	9,090	14,638
		Urban	9,239	12,198	3,696	16,213
		Semi-urban	2,723	6,593	1,089	8,890
		Rural	165	6,715	66	9,362
2040	5%	London	22,725	10,771	21,589	11,259
		Urban	9,239	12,198	8,777	12,717
		Semi-urban	2,723	6,593	2,587	6,887
		Rural	165	6,715	157	7,054
	25%	London	22,725	10,771	17,044	13,656
		Urban	9,239	12,198	6,929	15,288
		Semi-urban	2,723	6,593	2,042	8,297
		Rural	165	6,715	124	8,798
	60%	London	22,725	10,771	9,090	22,212
		Urban	9,239	12,198	3,696	24,725
		Semi-urban	2,723	6,593	1,089	13,715
		Rural	165	6,715	66	15,548

Per connection served, BAU Opex is higher in urban areas than in London due to the greater connection density in London (ie costs are spread over a greater number of connections). The same trend is seen when comparing rural and semi-urban contexts.

Figure 7-6 shows how NPV (Opex plus abandonment) of the partially decommissioned network per connection served varies with percentage of network decommissioned. This shows that the cost of serving a connection after partial decommissioning of the network increases as the percentage of network decommissioned rises.

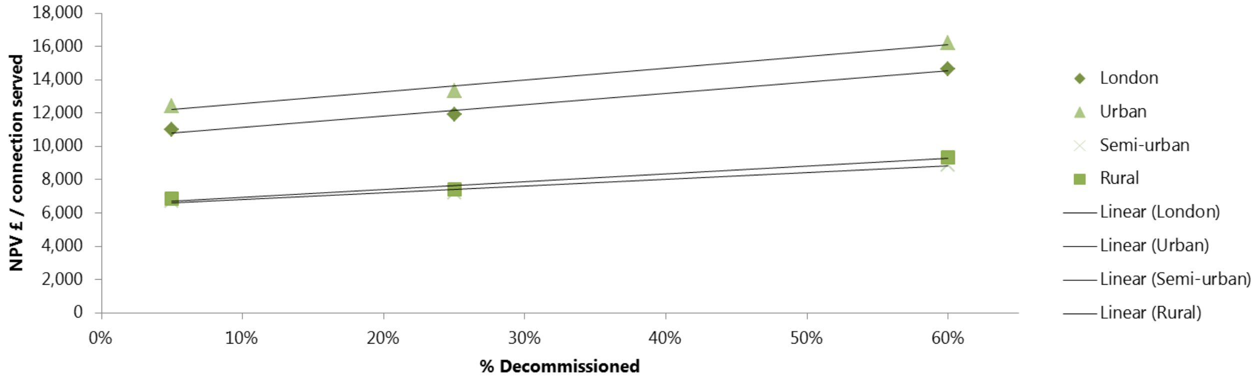


Figure 7-6 Variation of NPV per connection served with % decommissioned in different contexts (2020)

7.3 Limitations and further work

Limitations associated with this task are as follows:

- For this high level study, the decommissioning rate was applied equally across all Assemblies in the network. In practice there are likely to be many different ways in which the decommissioning could be undertaken depending on site specific factors. For example, there are likely to be constraints around which sections of a network could be safely abandoned without adversely impacting the overall operation of the network. Or, if the connections being decommissioned were randomly spread around the network, it is likely that more of the upstream infrastructure would remain in place than if all connections in a particular neighbourhood were decommissioned.
- This task is particularly affected by the modelling of Opex in the ICC. As noted in Section 3.4, this is to be revised in the next version of the tool and could give differing results.

Further work could usefully be undertaken to address both these issues such that design of particular decommissioning scenarios are analysed using the new version of the ICC.

8 G-I-6 Gas transmission network: repurposing to hydrogen (H_2)

8.1 Research question overview and scope

This research question was concerned with the cost of repurposing an existing gas transmission network to carry hydrogen (innovation) compared with building new hydrogen transmission lines and abandoning the existing gas ones (counterfactual).

The scope of the analysis is focused on a specific section of the gas transmission network (Feeder 10) from a gas production site through to connection to power generation in a rural area.

The schematic in Figure 8-1 shows the boundary, assemblies and network layout. Essentially the project comprises the transmission line section only (Feeder 10); compressor stations are not included.

In the context of the ICC, the Assemblies used to build the network are:

- Transmission: NTS: Buried: 36" gas pipe – repurposing mode (innovation)
- Transmission: NTS: Buried: 36" H_2 pipe – new build mode (counterfactual)
- Transmission: NTS: Buried: 36" gas pipe – abandonment mode (counterfactual)

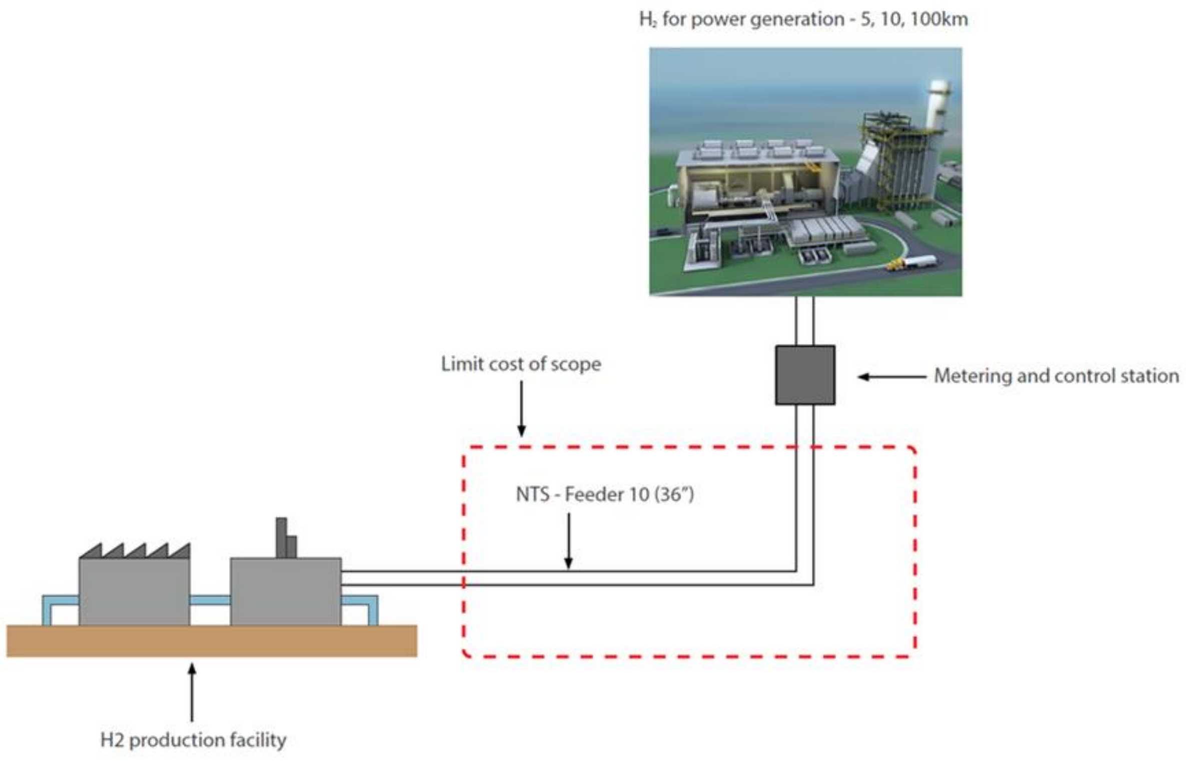


Figure 8-1. Network schematic indicating scope boundary

The research question was concerned with exploring costs with different pipe lengths and installation dates as summarised in Table 8-1. These variants were compared for the innovation and the counterfactual. Combining all the variants generated 6 data points for each, which form the basis of the analysis below.

Table 8-1 Variations to be costed

Parameter	Variants	Application
Repurposing date	2020 2040	Each date applied to each of the other variants
Capacity / pipe diameter	NTS gas (HP) - 36"	Single capacity tested
Context	Rural	Single context tested
Length	5, 50, 100km	Each length applied to each of the other variants

8.2 Results and Analysis

Table 8-2 shows the NPV Capex, NPV Opex, NPV Total and first costs for each variation explored in this task including the innovation and counterfactual. As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project.

Figure 8-2 illustrates the comparison between innovation and counterfactual.

Table 8-2 Base output data – innovation & counterfactual

Mode	Installation date	Context	Quantity (km)	First Cost (£m)	NPV Capex (£m)	NPV Opex (£m)	NPV Total (£m)
Counterfactual: New build H_2 & Gas NTS abandonment							
Abandonment / new build	2020	Rural	5	17.0	24.0	4.0	28.0
		Rural	50	146.0	205.0	31.0	236.0
		Rural	100	268.0	374.0	57.0	431.0
	2040	Rural	5	28.0	13.0	2.0	15.0
		Rural	50	239.0	111.0	18.0	129.0
		Rural	100	438.0	202.0	33.0	235.0
Innovation: Gas NTS repurposed							
Repurposing	2020	Rural	5	0.4	9.0	4.0	13.0
		Rural	50	3.9	80.0	30.0	110.0
		Rural	100	7.7	160.0	60.0	220.0
	2040	Rural	5	0.6	1.0	2.0	3.0
		Rural	50	5.5	9.0	18.0	27.0
		Rural	100	10.8	18.0	35.0	53.0

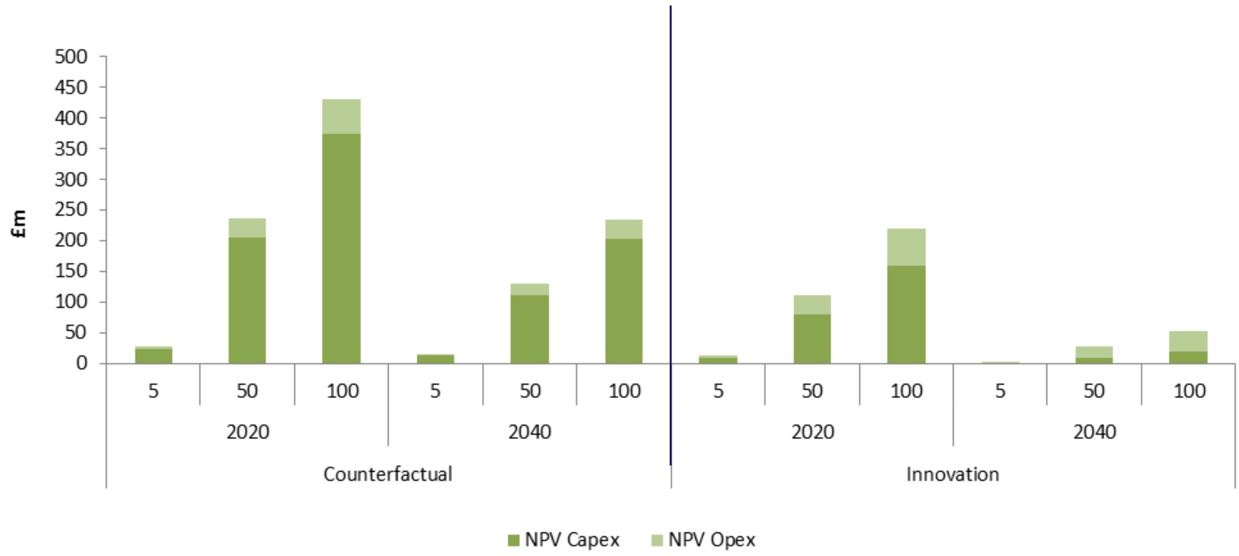


Figure 8-2 NPV (Capex and Opex) 2020 and 2040 for all network lengths

Key findings:

- The NPV Capex, Opex and Total for the innovation item are much lower than the counterfactual - the NPV Total is around 50% lower in 2020 for the innovation and nearly 80% in 2040. The difference by installation date is due to the application of lifecycle profiles within the ICC. If the project is deferred to 2040, the final major refurbishment cost (100% of new build Capex) occurs beyond the end of the analysis period (2075). The impact of this is far greater for the innovation as the repurposing costs are low and the refurbishment of the repurposed hydrogen asset does not occur within the project assessment period (ie before 2075).

  This is best understood by reviewing the Capex and repex cash flows for the different projects as extracted from the ICC and shown in Figure 8-3. The left hand graphs are for 2020 and the right hand graphs are for 2040. The top graphs are counterfactual cash flows for abandonment of gas; the middle graphs are the counterfactual cash flows for new build hydrogen; and the bottom graphs are the innovation cash flows for repurposing gas to hydrogen.

  As can be seen, for installations in 2020, the major refurbishment costs occur within the analysis period and are of equivalent size for the innovation and the counterfactual. For installations in 2040, the major refurbishment costs are beyond the assessment period so the key determinant of difference in NPV is the abandonment / new build cost versus the initial repurposing costs. The difference in these costs is significant.

  The impact of selecting a fixed analysis period combined with the way the ICC models lifecycle costs clearly has a significant impact on results. Further analysis to better understand this impact could be undertaken using the new version of the tool (see Section 0).

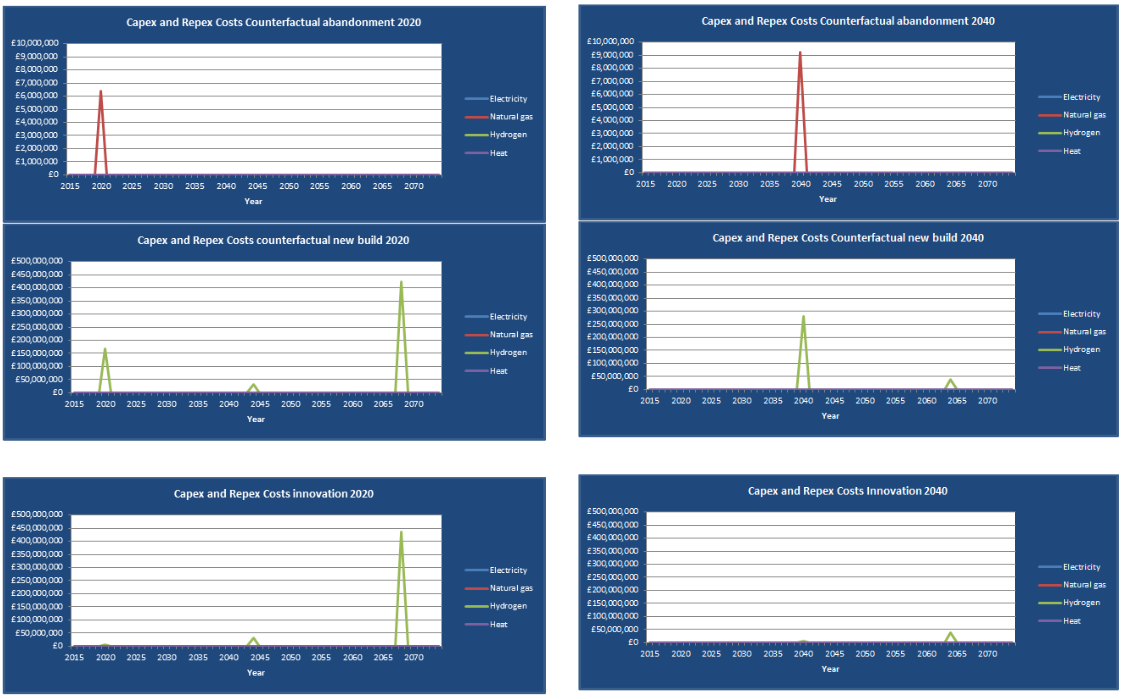


Figure 8-3 Capex and repex cash flows for the counterfactual and innovation in 2020 (LHS) and 2040 (RHS)

- The first costs (which exclude any lifecycle replacement costs) for the innovation are considerably lower than the counterfactual due to significant investment required to build the new H_2 NTS pipeline compared with repurposing the existing gas asset.

8.2.1 Analysis: Assemblies

This innovation task consists of a single assembly while the counterfactual is formed of two: new build H_2 NTS and abandonment of gas NTS.

The cost of the counterfactual is mostly driven by the cost of the new build H_2 pipeline, with the abandonment of the existing feeder 10 being a relatively small proportion of the total cost. Approximately 80% of the NPV Total derives from the new H_2 NTS pipeline while only 20% comes from the Feeder 10 abandonment.

8.2.2 Analysis: Normalised costs

Normalised costs for each variation as given in Table 8-2 are presented in Figure 8-4 and Figure 8-5.

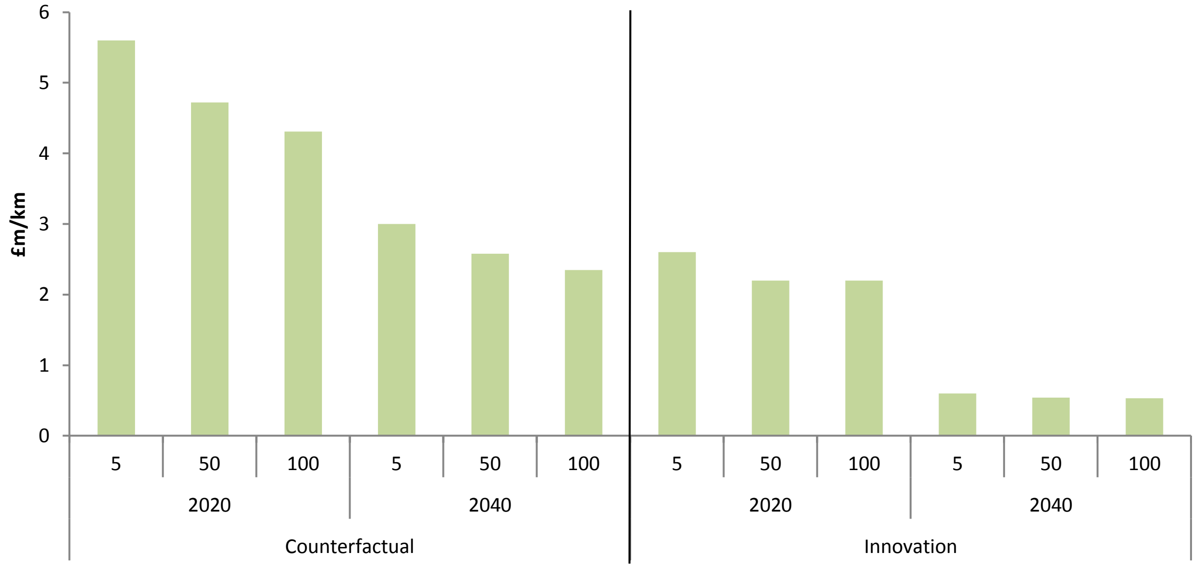


Figure 8-4 NPV Total cost £m/km

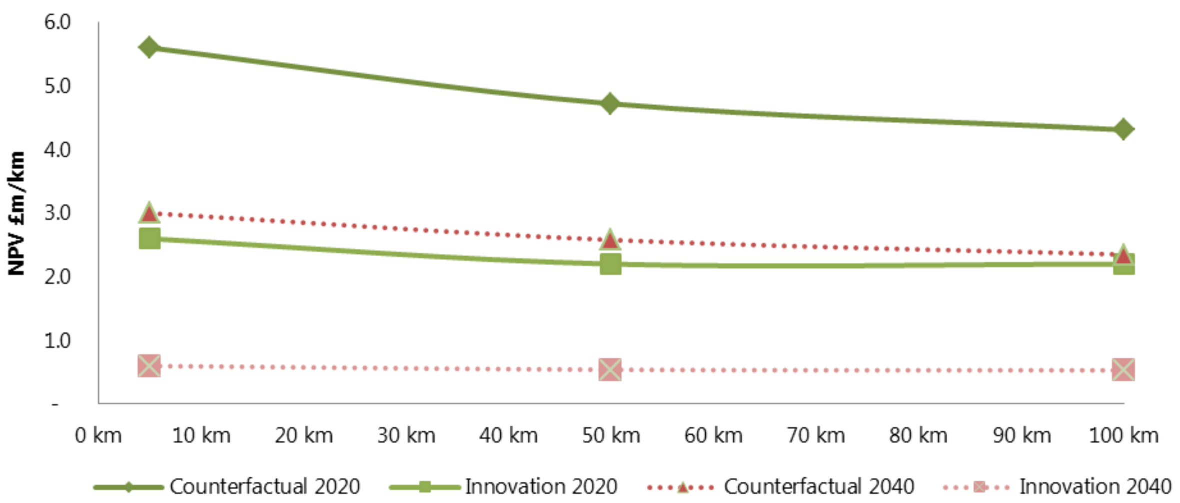


Figure 8-5 Variation of NPV total/km and network length

Key findings:

- The total NPV per km (£m/km) decreases with the pipeline length for all scenarios.
- The innovation variation shows significantly lower NPV costs per km than the counterfactual.
- NPV costs per km are also much higher in 2020 than 2040.

8.3 Limitations and further work

The limitations impacting the cost analysis include:

- The existing gas NTS feeder 10 has been assumed as per typical NTS pipeline material: epoxy coated X70 Steel Pipe with 0.375" thickness in line with API 5L standards. If a different material is finally identified for Feeder 10, this will have an impact on the cost of the innovation project calculated here.
- Natural gas equipment (pipework, valves, meters, etc.) will have to be tested to ensure that transporting hydrogen is suitable for the system minimising the equipment to be replaced.
- Some high grade steel used in NTS pipelines may be susceptible to hydrogen embrittlement, therefore testing and assessment of the material may be required. The risk of hydrogen embrittlement is difficult to predict. It depends not only on the material of the pipeline, but also on the pipeline's history.
- The cost analysis does not include losses which would impact on whole life costs, however losses are minimal at NTS levels. The volumetric losses of hydrogen as a consequence of leakage are always larger than those of natural gas, but the energetic losses are always smaller – hydrogen has a higher calorific value but lower density than natural gas.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in first version of the ICC. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in the second version of the tool which could impact on these results.

9 G-I-7 Gas transmission network: repurposing to carbon dioxide (CO2)

9.1 Research question overview and scope

This research question was concerned with the cost of repurposing an existing gas transmission network to carry CO_2 (innovation) compared with building new CO_2 transmission lines (counterfactual). The two cases (innovation and counterfactual) are considered in different operational conditions of pressure and temperature (P, T) but maintaining the same CO_2 capacity flow (8m tonnes/year). The scope of the analysis is based on the parameters outlined in Table 9-1.

Table 9-1 Parameters used for the study

Task description	Vector	Activity	Date	Capacity	Pipe diameter	Length	Context	Conditions (P,T)
Repurposing	Gas	Repurposing to CO_2	2020 2050	913 tonnes/hour (8m tonnes/year)	36" (900mm)	280km	Rural, semi urban	**Gaseous:** 35bar 293K
Counterfactual	CO_2	New CO_2 pipeline	2020 2050	913 tonnes/hour (8m tonnes/year)	24"(609.6mm)	280km	Rural, semi urban	**Dense Phase:** 150bar 293K

The schematic in Figure 9-1 shows the boundary, Assemblies and network layout. Essentially the project comprises 280km of transmission line (NTS) and the compressors/pumping stations required to maintain the operational conditions described above. The injection pump/compressor is not included in the scope.

In the context of the ICC, the Assemblies used for the analysis are:

- Natural Gas Transmission – NTS. Buried, 36" gas pipe - with repurposing for CO_2 (innovation)
- Natural Gas Compressor Station - with repurposing for CO_2 (innovation)
- CO_2 Transmission – NTS. Buried, 24" CO_2 pipe (counterfactual)
- CO_2 Pumping Station (counterfactual)

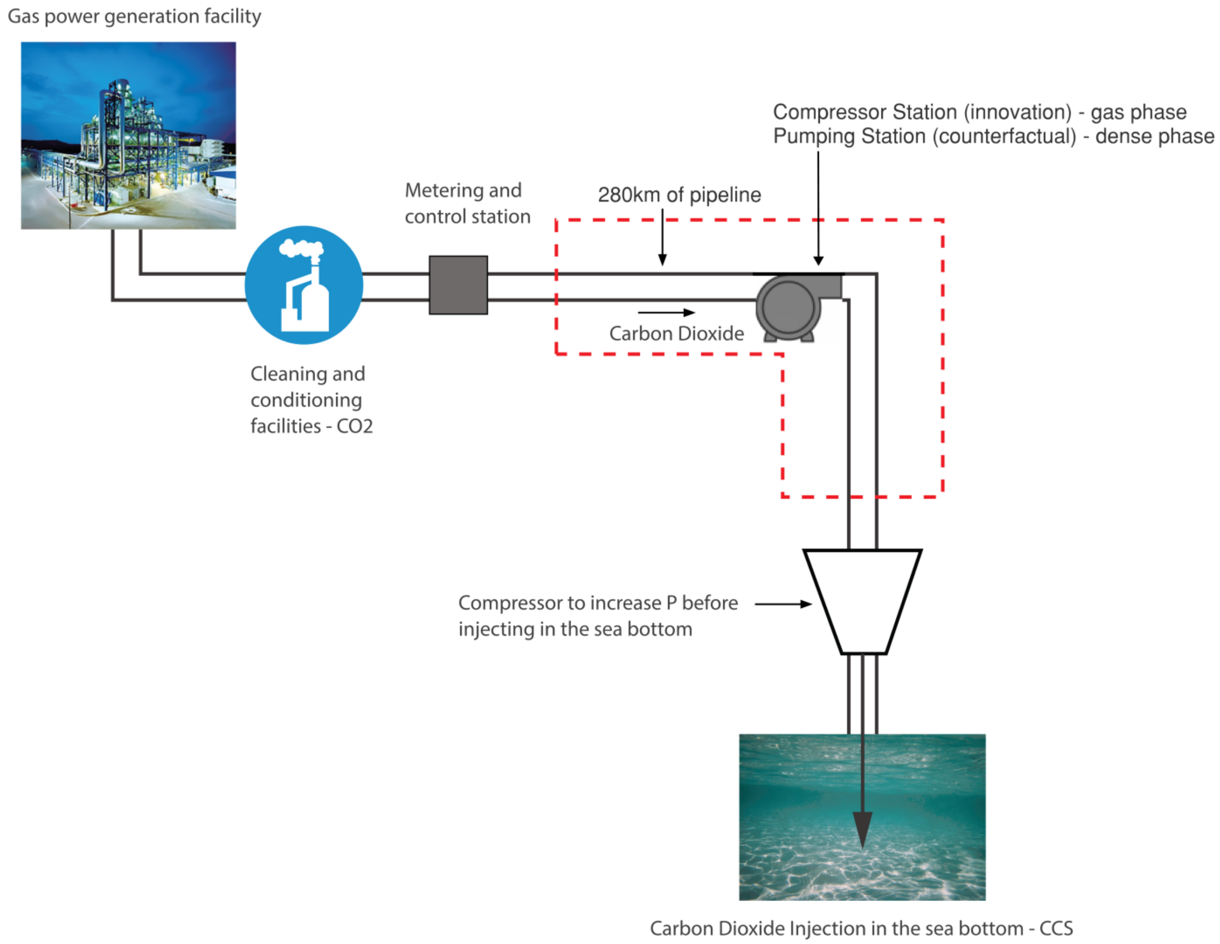


Figure 9-1 Network schematic indicating scope boundary

The research question was concerned with exploring costs with different contexts and installation dates as summarised in Table 9-2. These variants were compared for the innovation and the counterfactual tasks. Combining all the variants, this generated 4 data points for each (8 in total), which form the basis of the analysis below.

Table 9-2 Variants analysed

Innovation: Repurposing of gas transmission line to CO_2		
Parameter	**Variants**	**Application**
Repurposing date	2020 2050	Each date to be applied to each of the other variants
Capacity / pipe diameter	NTS – 36”	Single capacity
Compressor stations	Natural Gas Compressor Station*	Single capacity
Context	Rural, semi-urban	Two contexts
Length	280km	Single length
Mode	Repurposing	All costs to be repurposing
Counterfactual: New CO_2 transmission line		
Parameter	**Variants**	**Application**
Installation date	2020 2050	Each date to be applied to each of the other variants
Capacity / pipe diameter	NTS – 24”	Single capacity
Compressor stations	CO_2 Pumping Station**	Single capacity
Context	Rural, semi-urban	Two contexts
Length	280km	Single length
Mode	New build	All costs to be new build

** The capacity (under normal conditions) of the gas compressor in the ICC tool is 45% higher than the flow required for this task. The cost has been adjusted on a pro-rata basis for the purposes of this high level study (ie. 55% of the whole assembly cost has been included in the simulation). Typically gas compressor stations are located every 100km in the NTS pipeline, therefore 3 compressor stations are required to cover the total length of 280km. Note, the gas compressor in the ICC tool includes redundancy for resilience.*

*** To maintain the CO_2 in dense phase, one CO_2 pump station is required every 100km. For system resilience, the equipment required is doubled for each location. Applying this principle, the total number of CO_2 pump stations included in the cost analysis is 6 (3 x 2 = 6).*

9.2 Results and Analysis

Table 9-3 shows the NPV Capex, NPV Opex, NPV Total and first costs for each variation explored in this task including the innovation and counterfactual. As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project.

Table 9-3 Base output data

Mode	Installation date	Context	Quantity (km)	First Cost (£m)	NPV Capex (£m)	NPV Opex (£m)	NPV Total (£m)	NPV total per km (£m/km)
Innovation: Repurposing of gas transmission line to CO_2								
Repurposing (Innovation)	2020	Rural	280	46.2	558.2	199.0	757.2	2.7
		Semi-urban	280	50.7	786.5	233.2	1,019.7	3.6
	2050	Rural	280	96.8	34.4	77.0	111.4	0.4
		Semi-urban	280	106.2	83.1	90.2	173.4	0.6
Counterfactual: New build CO2 transmission line								
New build (Counter-factual)	2020	Rural	280	606.5	903.1	146.0	1,049.1	3.7
		Semi-urban	280	762.6	1,224.5	174.6	1,399.1	5.0
	2050	Rural	280	1,466.5	533.6	56.4	590.1	2.1
		Semi-urban	280	1,791.2	709.6	67.5	777.0	2.8

Figure 9-2 compares first costs of the innovation and counterfactual while Figure 9-3 shows the total NPV (Capex and Opex).

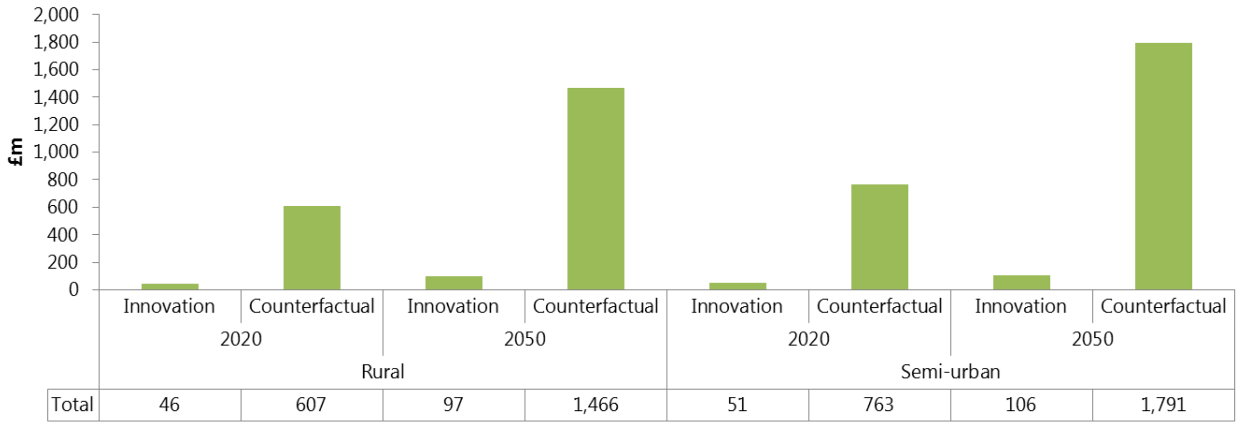
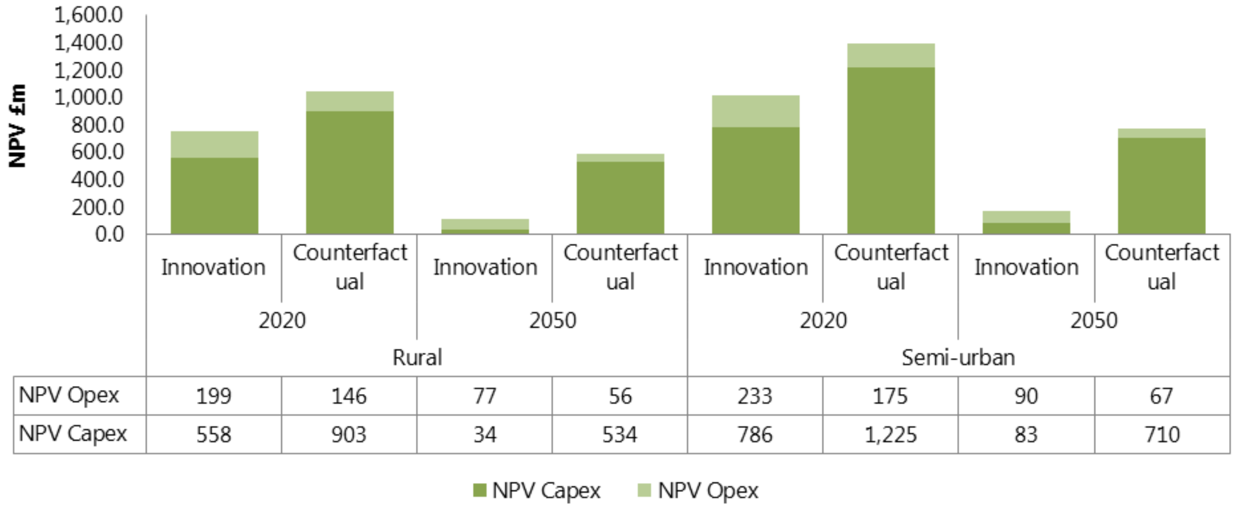


Figure 9-2 First costs of counterfactual and innovation in different contexts and at different dates



	Rural				Semi-urban			
	2020		2050		2020		2050	
	Innovation	Counterfactual	Innovation	Counterfactual	Innovation	Counterfactual	Innovation	Counterfactual
NPV Opex	199	146	77	56	233	175	90	67
NPV Capex	558	903	34	534	786	1,225	83	710

Figure 9-3 NPV total (Capex and Opex) of the counterfactual and innovation in different contexts and at different dates

Key findings:

- The first costs (which exclude any lifecycle replacement costs) for the innovation (repurposing) are approximately 93% lower than the counterfactual (CO_2 new build). This is due to significant investment required to build the new CO_2 NTS pipeline compared with repurposing the existing gas asset.
- Similarly, the NPV total for the innovation is around 30% lower than the counterfactual in 2020 and about 80% lower in 2050. NPV is affected by the treatment of opex and lifecycle costs in the ICC model which will be changed in v2.
- As expected, all costs are higher (around 10-20%) in a semi-urban context than a rural one due to higher costs associated a with more dense / congested environment.

9.2.1 Analysis: Assemblies

As noted, these projects (innovation and counterfactual) comprise two primary Assemblies each, 280km of transmission NTS pipeline and a compression station (repurposed gas compression station or CO_2 pump station).

Figure 9-4 shows the percentage contribution to total costs for these two Assemblies.

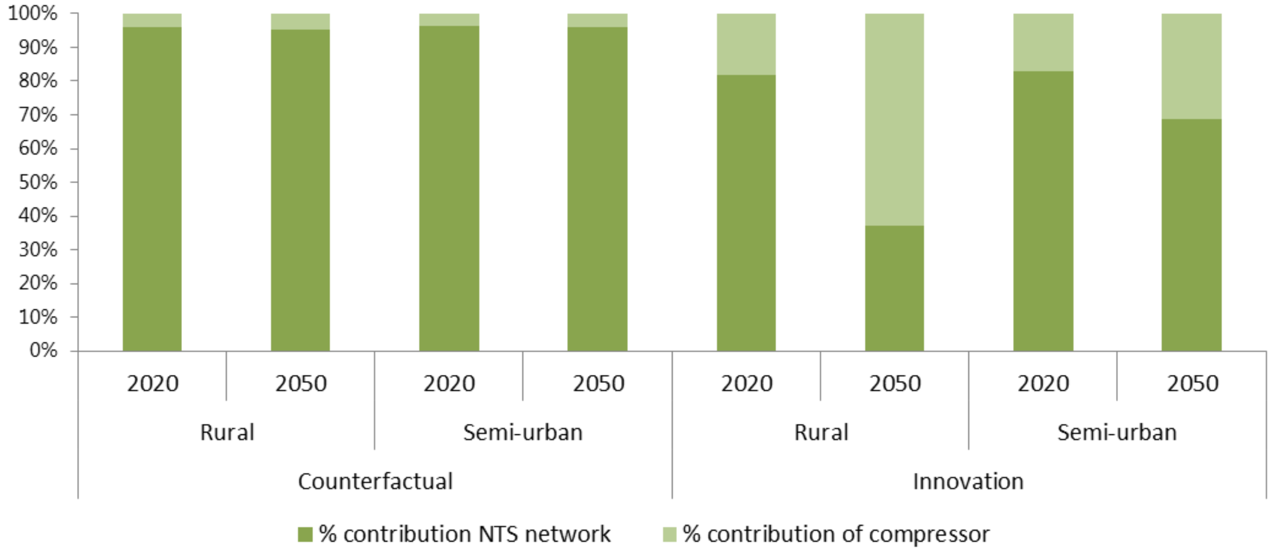


Figure 9-4 Share of costs of the two Assemblies, the network and the compressor

Key findings:

- When building a new CO_2 NTS system (counterfactual), the pipeline costs completely dominate the system, representing around 95% of total costs. This is consistent across contexts and for different installation dates.
- For repurposing (innovation), the picture is more varied. In 2020, around 80% of the costs relate to the NTS pipeline and 20% to the gas compressor in both contexts. In 2050, the relative percentages change, particularly in the rural context. This is a consequence of the modelling of lifecycle costs in the tool which assumes assets last longer in a rural environment. As a consequence, the next refurbishment cycle is beyond the assessment period in the rural context for an installation date of 2050 and therefore the costs of refurbishment are not included in the above assessment; they are however included in the semi-urban context. Thus in 2020 in both contexts and in 2050 in a semi-urban context, the pipelines dominate, largely due to their costs of refurbishment. In 2050 in a rural context however, where no refurbishment costs are included, the compressor costs dominate. This result will be impacted by the revised approach to lifecycle costing being implemented in the next version of the ICC.

9.2.2 Analysis: Normalised costs

All costs in Table 9-3 are per 280km of pipe length; no further normalisation costs have been calculated as the trends would be the same. However, Table 9-3 shows the total NPV cost per km (£m/km) of pipeline which varies in the same fashion as the total NPV cost.

9.3 Limitations and further work

The limitations impacting the cost analysis include:

- For the counterfactual, the abandonment cost of the existing gas transmission line is not included in the analysis as the construction of a new CO_2 transmission line does not necessarily implies the decommission of the existing gas transmission line. The natural gas NTS network can still perform as a gas asset.

- The two scenarios (innovation and counterfactual) are not strictly comparable as they transport CO_2 in very different operational conditions. However, they have been considered to transmit the same CO_2 flow.
- For the counterfactual (new build CO_2 in dense phase), the CO_2 is assumed to be in the dense phase when it enters the NTS network. Converting to the dense phase is most likely to take place at the factory/power station where the CO_2 is produced.
- For the innovation, repurposing the existing gas compressor station to CO_2 is assumed to be achieved through cleaning, adjusting, control modification, drying and testing of the plant without the need for any substantial plant replacement.
- For the innovation, the existing gas compressor in the ICC tool has been proportionally included in the cost simulation (only 55% of the cost) to match the flow required in the task.
- The cost analysis does not include losses which would impact on whole life costs. However, losses would be minimal in new build or recently repurposed infrastructure.
- The results achieved for the split of costs between Assemblies in the different contexts in 2050 would benefit from being re-run in ICCv2.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in first version of the ICC. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in the second version of the tool which could impact on these results.

10 G-I-8 Natural gas conversion: gas injection points

10.1 Research question overview and scope

This analysis is intended to provide a reference cost for incorporating injection points of different bio-gases or synthetic gases into the natural gas distribution and transmission network in rural areas.

The basis of design follows examples of alternative gas injection into the grid from UK-based case studies.

Figure 8-1 provides a schematic for a typical network and injection point, indicating the boundary of the cost scope. Essentially this task comprises the Biomethane to Grid Plant (BtG) and distribution pipelines connecting to the grid. In the context of the ICC, the Assemblies used to build the network are:

- Conversion assembly: Biomethane to Grid Plant (BtG) – includes analysers, instrumentation and control equipment
- Distribution assembly: MP: Buried: 6" gas pipeline (300,000 m^3/day)

This innovation task in particular (G-I-8) does not have a counterfactual as there is no equivalent 'business as usual' infrastructure that it would be replacing.

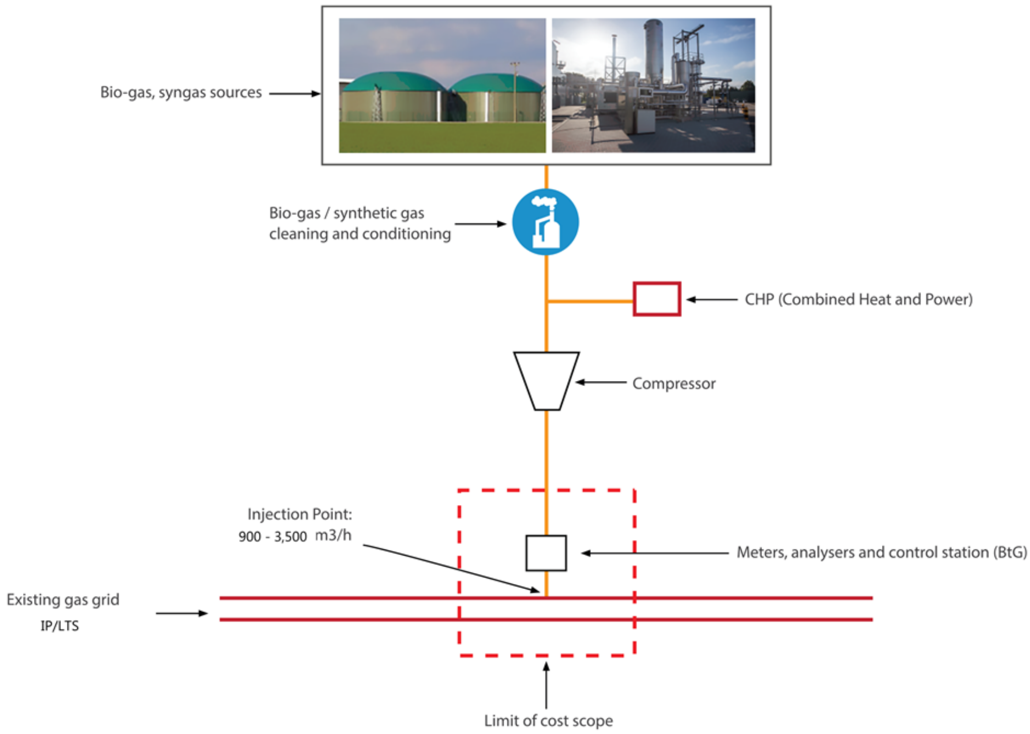


Figure 10-1 Network schematic indicating scope boundary

Table 10-1 provides the Bill of Quantities and project variants for this analysis. Combining all the variants generated 16 data points which form the basis of the analysis below.

Table 10-1 Variations to be costed

Parameter	Variants	Application
Installation date	2020 2050	Each date applied to each of the other variants
Capacity / pressure level	900 m^3/hr – IP connection 3,500 m^3/hr – IP/LTS connection	Each capacity applied to each of the other variants
Length (km)	1, 10	Each capacity applied to each of the other variants
Context	Rural Urban	Each context applied to each of the other variants
Mode	New build	All costs new build

10.2 Results and analysis

Table 10-2 shows the main output data for each scenario explored in this task. These are presented in Figure 10-2. As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project.

The table also includes normalised costs (NPV) per m^3 and per km. These are discussed in Section 10.2.2 below.

Table 10-2 Base output data

Installation date	Capacity (m^3/hr)	Context	Pipe length (km)	First cost (£m)	NPV capex (£m)	NPV Opex (£m)	NPV total (£m)	NPV per m^3 (£/m^3)	NPV/km (£m/km)
2020	900	Rural	1	5.1	6.7	1.1	7.8	9,000	7.8
		Rural	10	20.2	26.4	4.9	31.3	35,000	3.1
		Urban	1	9.9	14.4	2.2	16.6	19,000	16.6
		Urban	10	62.1	89.7	15.3	105.0	117,000	10.5
2050		Rural	1	10.8	3.9	0.4	4.4	5,000	4.4
		Rural	10	48.1	17.2	1.9	19.1	22,000	1.9
		Urban	1	22.2	8.9	0.9	9.8	11,000	9.8
		Urban	10	151.6	56.8	5.9	62.7	70,000	6.3
2020	3,500	Rural	1	11.8	15.4	2.4	17.8	6,000	17.8
		Rural	10	26.9	35.1	6.2	41.3	12,000	4.1
		Urban	1	17.6	25.9	3.8	29.6	9,000	29.6
		Urban	10	69.8	101.2	16.8	118.0	34,000	11.8
2050		Rural	1	23.6	8.6	0.9	9.5	3,000	9.5
		Rural	10	60.9	21.9	2.4	24.3	7,000	2.4
		Urban	1	36.9	15.5	1.4	17.0	5,000	17.0
		Urban	10	166.3	63.5	6.5	70.0	20,000	7.0

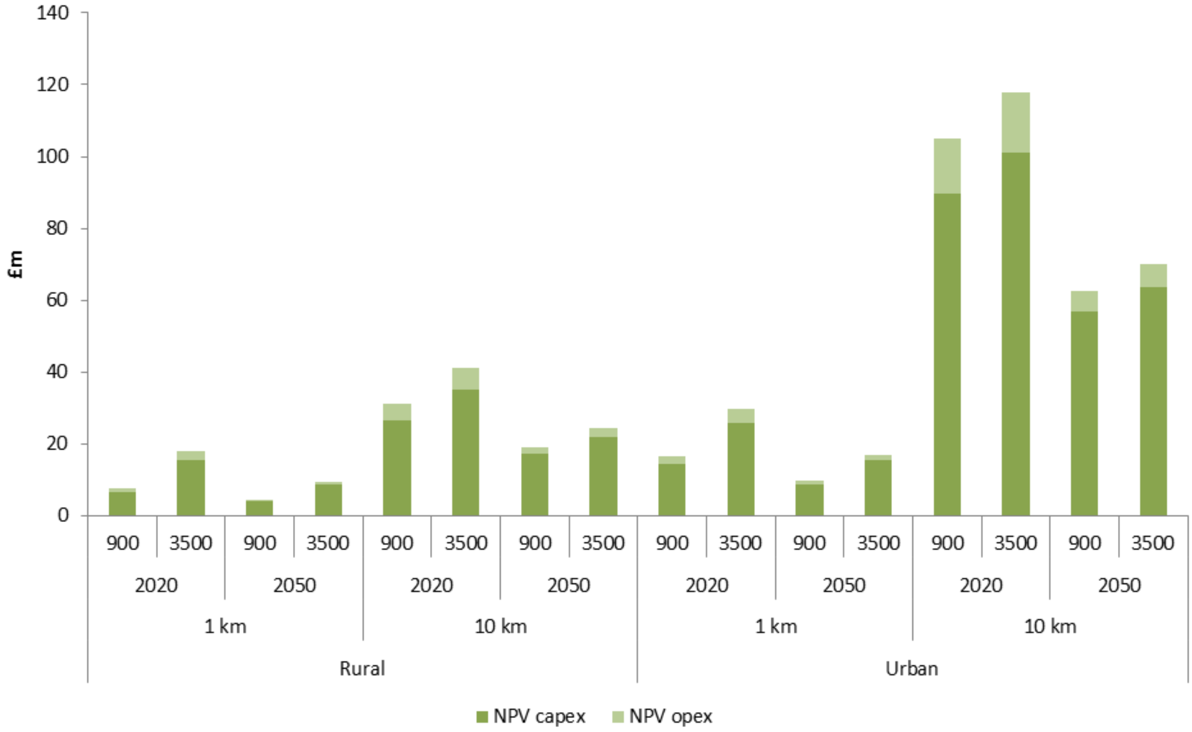


Figure 10-2 NPV (Capex and Opex) 2020 and 2050 for all variants

Key findings:

- Firsts costs are higher in urban than in rural areas for all lengths and capacities due to the higher costs associated with installing pipework in more congested or urbanised areas.
- Total NPV costs are higher for installations in 2020 than 2050. This is because although first costs are higher at later installation dates (due to the effect of indexation as discussed in Section 3.2.5), the effect of discounting back to 2015 means that NPV costs are lower.
- The higher gas injection capacity leads to higher overall costs due to the requirement for larger scale equipment.
- A larger increase in cost occurs in an urban context with longer pipe lengths than a rural context due to the additional costs associated with installing pipework in more populated areas.
- The difference in cost between 900 and 3,500 m^3/h gas injection capacity is less pronounced with longer pipe lengths. This is because as the pipe length increases, it represents a higher share of total cost. Thus the impact of requiring a larger BtG Assembly for a higher capacity becomes less significant. This demonstrates that pipe length has a high impact on costs.

10.2.1 Analysis: Assemblies

The relative costs of Assemblies for each project are given in Figure 10-3.

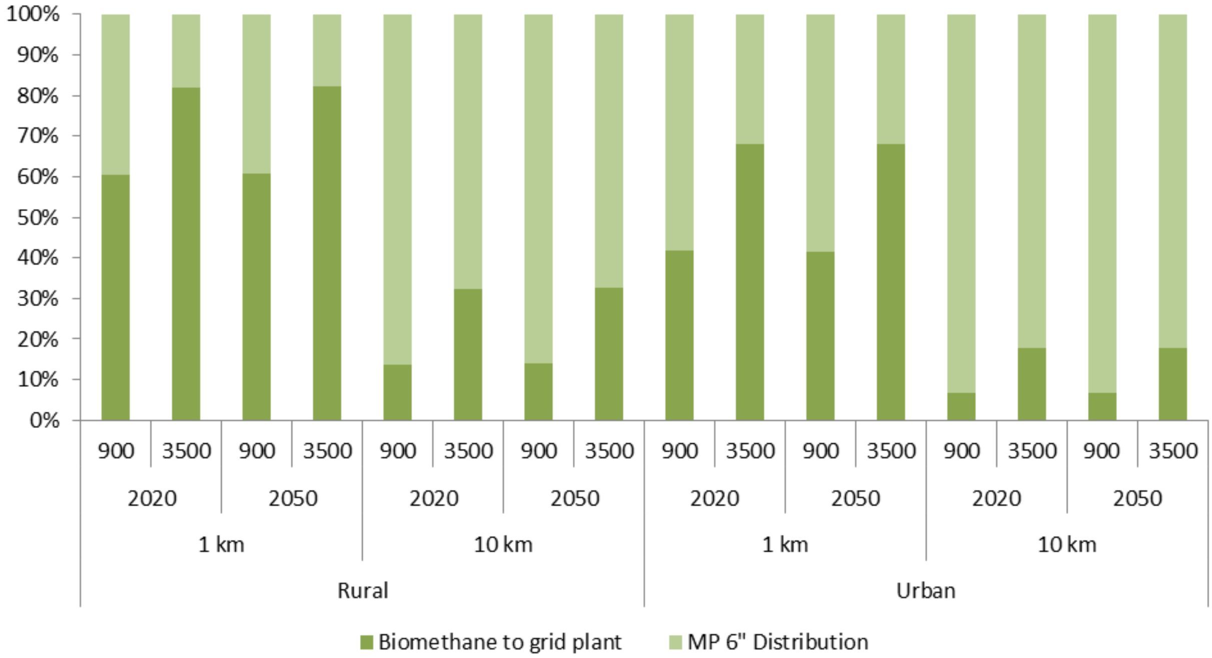


Figure 10-3 Percentage contribution of each Assembly to total cost

Key findings:

- BtG Assembly costs are more significant proportionally in rural contexts than in urban ones. This is due to the differing costs of installing pipework in the two contexts. In urban areas, installing pipework is more expensive than in rural ones, thus the significance of pipework costs relative to BtG costs is higher.
- The significance of pipework costs compared with BtG Assembly costs increases with network length as would be expected.
- BtG Assembly costs are more significant than pipework costs at higher gas injection capacities. This is due to the larger BtG unit required.

10.2.2 Analysis: Normalised costs

Normalised costs for each project as given in Table 10-2 are presented in Figure 10-4.

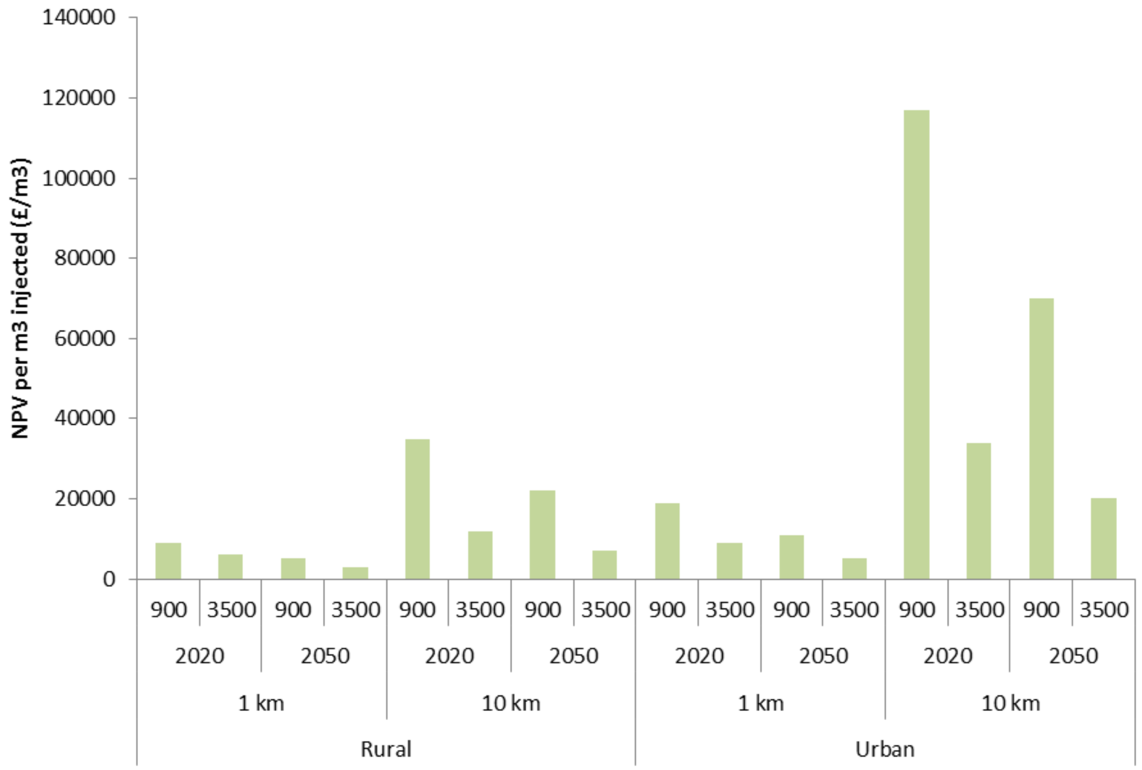
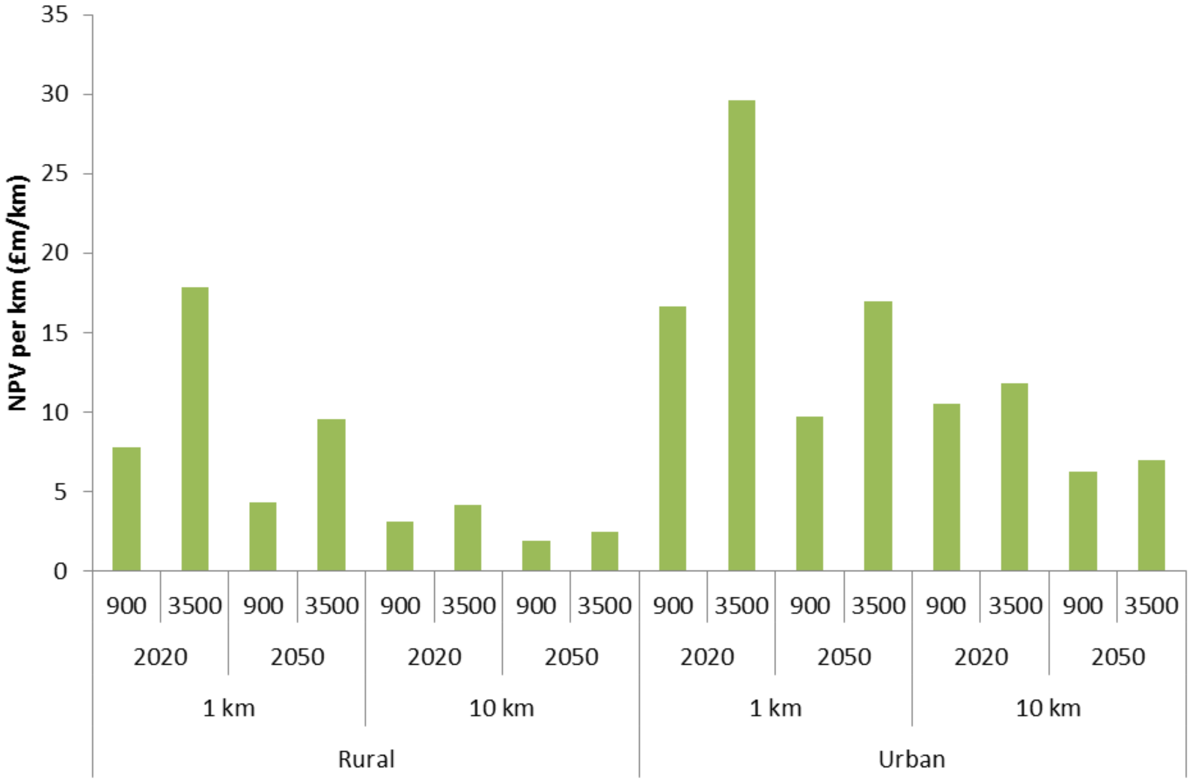


Figure 10-4 NPV per m^3 of gas injected



Key findings:

- There is a significant reduction in cost per km for each additional km of piping. This is due to the economies of scale and the cost of ancillary and installing equipment which are normally incurred once.
- Costs per m^3 gas injection are lower with larger capacities of gas injection due to the economies of scale.
- See Table 10-2 (last two columns) for more details on normalised costs.

10.3 Limitations and further work

The limitations impacting the cost analysis include:

- The cost analysis does not include losses which would impact on lifecycle costs.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in first version of the ICC. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in the second version of the tool which could impact on these results.

11 Summary

11.1 Key results

Some findings are the same across all projects. These include:

- First costs are higher at later installation dates. This is due to the impact of the cost trends in the ICC which inflate labour, material and plant costs over time (see Section 3.2.5). There are clearly alternative views on cost trajectories and these will influence the relative impact of deferring installation.
- NPV (Capex plus Opex) is lower for projects installed at a later date. Two factors come into play here: one, as expected, is the impact of discounting; the other is the way in which lifecycle costs are modelled in the ICC and the fact that the analysis has been undertaken for a fixed period of 60 years (2015 to 2075) irrespective of the installation date. Lifecycle costs include for a major refurbishment (100% of new build costs) at a fixed period after first instalment. For later installation dates, this major refurbishment may be beyond the analysis period and therefore not be included in the NPV calculation.
- Opex represents a relatively small proportion of whole life costs. It should be noted that the modelling of Opex is to be revised in the next version of the ICC which may influence the outturn values. Note also that Opex does not include the cost of losses.

A summary of findings specific to each project is given in Table 11-1.

Table 11-1 Key findings for gas network research projects

Ref*	Title	Key findings
		Generic
G-G-2	Representative Gas Distribution Model: connecting networks to transport sites at different capacities for different network lengths, in rural, semi-urban, urban and London contexts	• Context is a strong influencer of costs, with costs increasing from rural through to urban and London. This is due to the higher costs of installing pipework in more congested areas. • Pipe costs dominate the overall network cost, particularly for the longer network lengths. • Pipe capacity and hence size (6” MP or 12” LP) has some influence over cost at the longer network lengths where pipe costs are the most significant element. At these longer lengths, the MP network costs are lower than the LP network costs. • Normalised costs (ie costs per km) fall with increasing network length. This is largely due to the spreading of the single compressor cost over a longer network length.
G-G-3	Generic decommissioning costs (transmission), 100km length at different capacities / pipe sizes, rural context	• Decommissioning costs (NPV Opex in 2015 for networks decommissioned in 2020) are of the order of £90k/km. • Decommissioning of the pipework comprises around 80%-85% of cost, with the remaining 15%-20% relating to decommissioning the conversion station. • Pipe size has a minimal impact on cost.
G-G-4	Generic decommissioning costs (distribution) for different contexts and populations	• Decommissioning costs (NPV Opex in 2015 for networks decommissioned in 2020) range from around £250k/km in London down to £60k/km in rural areas. • The relative importance of the different Assemblies in terms of share of cost varies with context: decommissioning the LP network represents the largest share of cost in rural areas (60%) and decommissioning domestic connections represents the largest share of cost in London areas (58%).

Ref*	Title	Key findings
G-G-5	Generic operational costs associated with remaining part of a partially decommissioned network (distribution)	• In each context, reduction in Opex with increasing decommissioning is linear. This is a reflection of the modelling approach, where both direct and indirect costs are prorated to asset value. • Direct costs represent approximately 80% of the overall Opex for gas distribution infrastructure with indirect costs (including both closely associated costs and business support costs) making up the remainder. • Decommissioning (abandonment) costs make up a small share of overall cost with the NPV of Opex saved being 5 to 10 times higher. • After partial decommissioning, NPV (Opex plus abandonment) of the partially decommissioned network per connection served increases as the percentage of network decommissioned rises. • This task is particularly affected by the approach to modelling Opex in the ICC which is to be revised in the next version.
		Innovation
G-I-6	Gas transmission network: repurposing to hydrogen for different network lengths in a rural context	• Overall the innovation of repurposing existing natural gas transmission networks to carry hydrogen is roughly half the cost (NPV in 2050 for repurposing undertaken in 2020) of abandoning those same networks and building hydrogen pipelines from scratch • NPV/km decreases slightly with network length for both the innovation and the counterfactual
G-I-7	Gas transmission network: repurposing to carbon dioxide for single network length in rural and semi-urban contexts	• The task compared repurposing existing gas transmission pipelines to carry gas phase CO_2 compared with building new transmission pipelines to carry dense phase CO_2. Although operational conditions of pressure and temperature (P, T) were different, they maintain the same CO_2 capacity flow (8m tonnes/year). • Both first costs and NPV are higher for the counterfactual (new build) than for the innovation (repurposing) due to the high costs of installing new transmission pipelines. • As expected, all costs are higher (around 10-20%) in a semi-urban context than a rural one due to higher costs associated a with more dense / congested environment.
G-I-8	Natural gas conversion: installation of Biomethane to Grid injection points with different network lengths and capacities in rural and urban contexts	• The cost of installing Biomethane to Grid plant is higher in urban areas than in less dense rural ones mostly due to the additional cost associated with installing pipework associated with the connection point in more congested areas • Normalised costs per km fall with increasing network length • Normalised costs per m^3 gas decrease with increasing gas injection capacities

** Note that task ref G-G-1 was not carried forward into this study*

11.2 Further work

Areas for further work relate to the scope of some tasks and to issues arising from the design of the ICC. These are discussed below.

11.2.1 Scope related issues

- G-G-2: consider the impact on cost of including a metering and control station and connection to the network.
- G-G-3: consider the impact on cost of including the upstream compressor.

- G-G-4: the reliance on single locations to represent particular types of location remains a limitation of the analysis. Further work could include the analysis of additional locations to better understand and develop general cost trends.

Some of the above may require the costing of additional Components and Assemblies in the ICC.

11.2.2 ICC issues

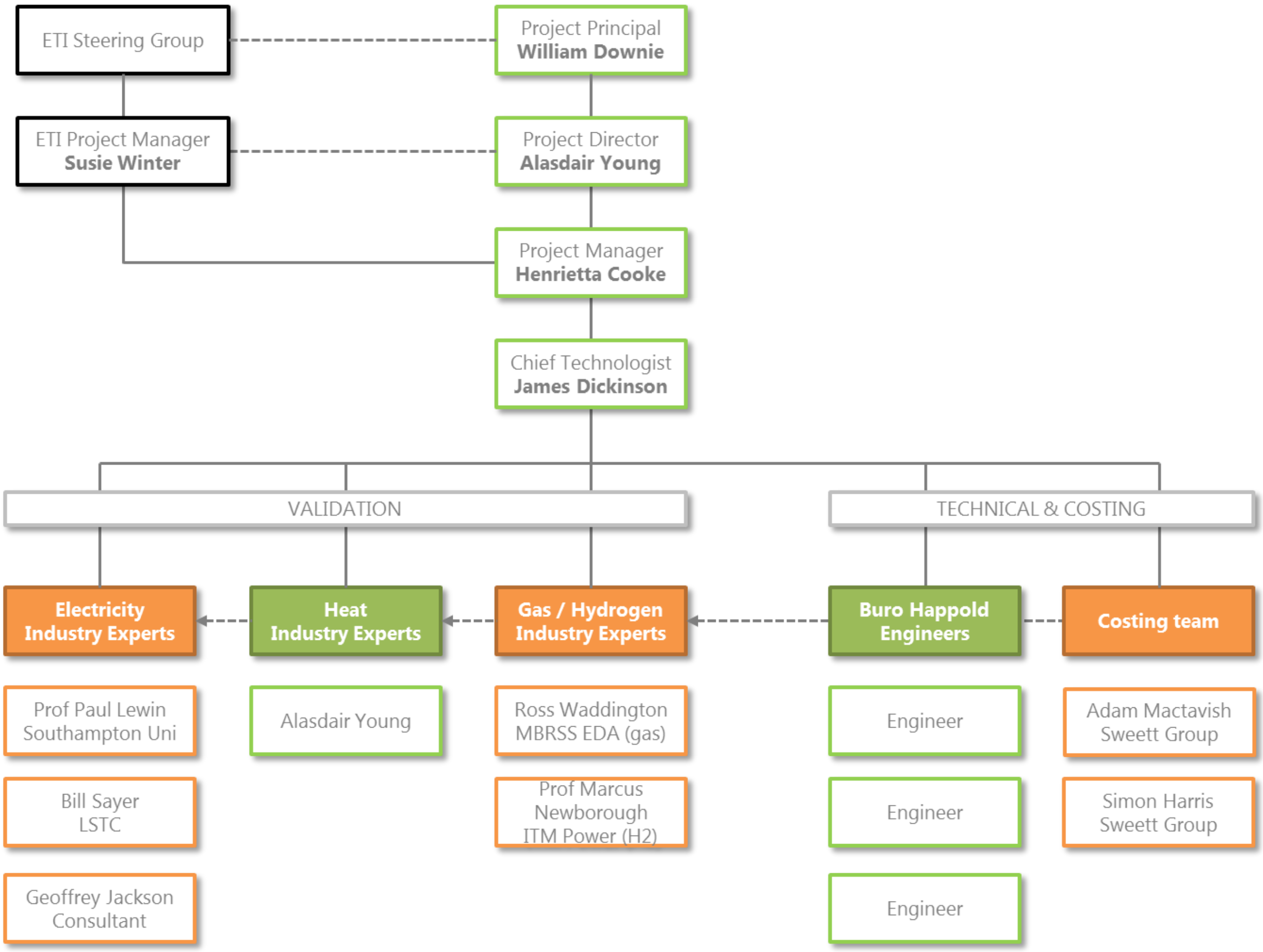
Analysis undertaken for a number of tasks raises the question as to whether the single assessment window (2015-2075) for all projects is appropriate. The primary reason this has arisen as an issue is the manner in which lifecycle costs are modelled in the ICC. As described in Section 3.2.4, lifecycle profiles are applied to each Assembly such that cash flows associated with minor and major refurbishments and with ultimate abandonment are deemed to occur in full in certain years. The effect of this is that a major refurbishment may be scheduled to occur beyond the analysis period for installations made at a later date. In the new version of the ICC, this approach is to be replaced with one that takes a more probabilistic view of replacement costs such that they are spread over the life of the asset. This approach would mitigate the effect of having a fixed analysis period.

Cost trends are being revised in the new version of the ICC.

The impact of the above suggests that further work could include re-running all tasks in the new version of the ICC. Sensitivity to cost trends could also be tested.

Appendix A Project Team

The overall project team is given in the organogram with details of the industry experts in the table below.



Role	Individual Experience & qualifications
Industry Expert – Electricity Provision of expert advice and design validation in relation to HVDC and transmission voltage HVAC cabling and power electronics	**Professor Paul Lewin, Southampton University** BSc (Hons), PhD, CEng, FIET, FIEEE Professor Lewin is Professor of Electrical Power Engineering in the School of Electronics and Computer Science, where he is also head of the Tony Davies High Voltage Laboratory. His research interests are within the generic areas of applied signal processing and control. Within high voltage engineering this includes condition monitoring of HV cables and plant, surface charge measurement, HV insulation/dielectric materials and applied signal processing. In the area of automation he is particularly interested in the practical application of repetitive control and iterative learning control algorithms. He is Vice President (Technical) of the IEEE Dielectrics and Electrical Insulation Society as well as an Associate Editor of the IEEE Transactions on Dielectrics and Electrical Insulation.
Industry Expert – Electricity Provision of expert advice and design validation in relation to AC Overhead Lines at all voltages	**Bill Sayer, LSTC Ltd** I. Eng. MIET Bill is currently a consultant with LS Transmission Consultancy Ltd where his key responsibilities are overhead line design, engineering specifications, component design/ specification, product evaluation and formulating construction procedures (wood pole and steel towers up to 400kV). Prior to working at LSTC, he was design manager for overhead lines for Balfour Beatty Utility solutions where he was responsible for the management of all engineering design issues on steel tower and wood pole overhead lines up to 400kV operation. He is Chairman BSI PEL/11 committee - Overhead Lines and UK Delegate CENELEC TC/11 WG9 – Revision to EN 50341 OHL Design > 45kV.
Industry Expert – Electricity Provision of expert advice and design validation in relation to AC Overhead Lines at all voltages	**Peter Papanastasiou, LSTC Ltd** BSc (Hons) C. Eng. MICE, FEANI (Eur Ing) Peter is a Director of LS Transmission Consultancy Ltd which has as its core business feasibility studies, topographical and ground surveys, concept and detailed design for projects for the Railway and High Voltage Electrical Power Engineering industries, in particular Overhead Lines and Substations in the power sector.
Industry Expert – Electricity Provision of expert advice and design validation in relation to electricity distribution focused on below ground electricity cabling at distribution voltages and substations.	**Geoffrey Jackson, Consultant** BSC (Hons) C. Eng Geoffrey has a long career in the electricity distribution sector from the operational level through general supervision to project management, including the installation, commissioning, safe operation, maintenance and dismantling of HV switchgear to 33kV, high and low voltage cables and cablejointing, high and low overhead lines. Other experience includes: • Project management including planning, design, tender issue and appraisal, construction and commissioning. • Extensive experience in asset condition appraisal and asset management with particular emphasis on switchgear, transformers and high voltage lines and cables.
Industry Expert – gas / hydrogen Provision of expert advice and design validation in relation to gas and hydrogen networks at all pressures.	**Ross Waddington, E Donald & Associates** Incorporated Engineer – Institute of Gas Engineers and Managers (IGEM) Ross is an Associated Director at E Donald & Associates. He is a highly experienced Senior Consultant Engineer specialising in all forms of pipeline engineering. As a Senior Manager has led multi-disciplined design teams on major Regeneration and large scale Renewable Energy projects across the UK.

Role	Individual Experience & qualifications
Industry expert – hydrogen Provision of expert advice in relation to hydrogen infrastructure	**Marcus Newborough, ITM Power** FREng CEng MSc PhD Marcus is Development Director at ITM Power where he supervises the analysis of existing and new electrolyser applications, hydrogen system design requirements for business development opportunities and demonstration projects, and the development of electrolyser products. Prior to joining ITM, he was a Research Chair at Herriot-Watt University where he led the Heriot-Watt Energy Academy as a pan-university mechanism for building partnerships in energy-related research. He established a research group which investigated pathways to a lower-carbon energy system, focusing on the assessment of demand side solutions in buildings, micro-generation, DSM and hydrogen energy systems.

Appendix B Project cost functionality

Extract from:

Energy Infrastructure 2050 Final Report, 22 November 2013, available from the ETI

Overview

The model contains a wealth of information and is provided with a number of tools and interfaces to enable users to adapt it to their needs and to extract data in ways that are both meaningful and useful. Its modular structure ensures that it is 'future proof' in that new Components and Assemblies can be added as required, either as more detailed cost data becomes available or an innovative technology becomes available. Data is also available to be extracted for use in other models or form as it is all in Excel cells which can be read by other applications or spread sheet tools.

It is anticipated that the primary use of the model will be in exploring the costs of projects and comparing options to help determine an optimal solution. In this chapter an overview of the Project functionality is provided along with some specific examples of questions the model can help in answering.

As mentioned elsewhere in this report, it must be noted that **the cost model does not allow for any form of system design.** Projects need to be designed as a separate exercise such that they can be expressed as a 'bill of quantities' (BoQ)[11] of constituent Assemblies. This 'bill of quantities' is used to model various aspects of the Projects for comparative purposes.

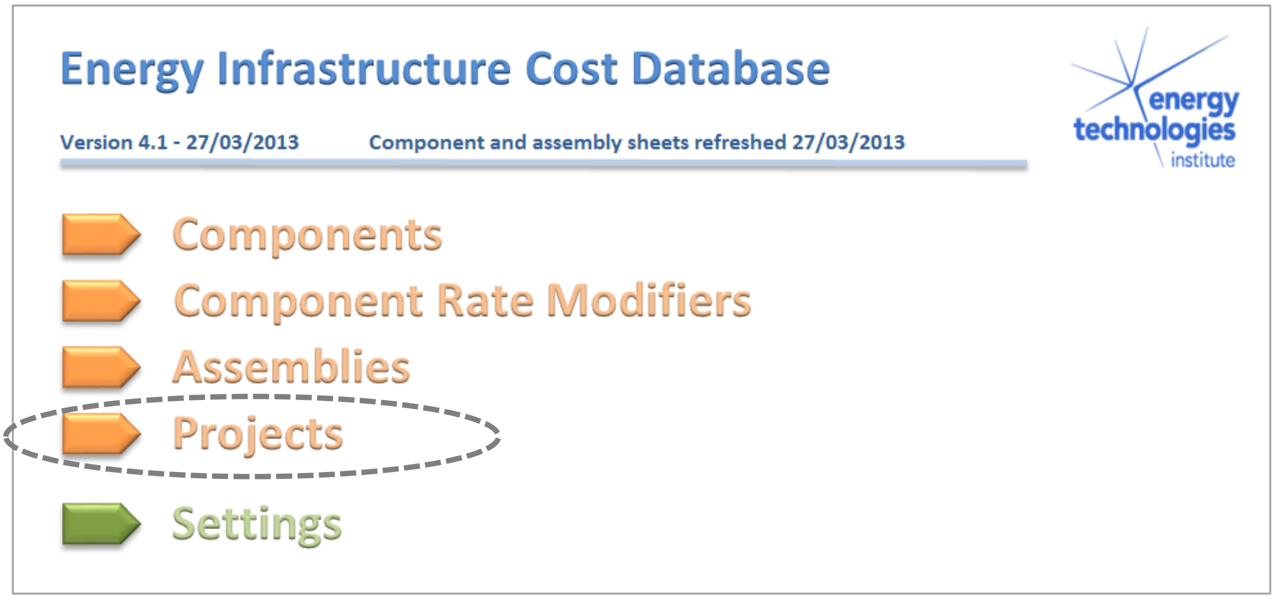


Figure B—1: Screen shot of start page of Infrastructure Cost Model

[11] The term 'bill of quantities' is used to refer to the data required to be input to the cost model in order to extract overall project costs. The quantity of each Assembly used to build the Project is required and this is input via the Project Data sheet of the model. This is further explained in the User Manual.

Project functionality

The Project functionality is a key analytical tool within the Cost Model. It enables users to cost systems of Assemblies which can be compared under different variations. In particular it allows for:

- The analysis of Projects of any scale or level of complexity from a single Assembly of a single vector to a multiple range of Assemblies across different vectors
- The creation of Projects that involve a transition over time such as the repurposing of gas to hydrogen over a 20 year period, or the inclusion of a transformative technology mid-way through the analysis period
- The modification of future cost trends so as to take into account the user's view of market factors both at a Project wide scale and individually for differing technologies as encapsulated by Components. These modifications can reflect general economic assumptions (such as labour rates / skills shortages) and technology specific assumptions such as the impacts of technology maturity and rates of deployment.

The details of how Projects are created within the model are provided in the User Manual. Key aspects of their structure and use are provided below.

Project cost calculation

Cost build up from Components and Assemblies

The calculation of Project costs uses the maximum and minimum capital cost of all Components to determine upper and lower bounds of total Project cost over the Project life. Project baseline cost is determined using rate modifiers, described in Section 7.3.3 and as outlined schematically in Figure 8—2, applying a simplified triangular Monte Carlo simulation model using the maximum, minimum and most likely cost values and allowing the user to interrogate cost probabilities based on Component cost variability.

A Project can specify quantities of Assemblies at different operational stages, that is new build, refurbished, repurposed or abandoned, each to be added at a specific period. Costs of each operational stage are built up for each Assembly and then for the Project as a whole based on:

- Capital costs
- Lifecycle costs
- Operating costs

The build-up of each of these cost profiles at the Component and Assembly level is described in Chapter 7. The user has the option to define each of the rate modifiers at the Project level or for individual Assemblies. The Project contains cost profile information for each Assembly covering each year of the defined lifecycle period.

Operating costs over this period will vary as the asset ages in line with the operating cost profile assigned to the Assembly and the major and minor replacements scheduled in the assembly lifecycle plan. For new build Assemblies there is no existing asset to be replaced, repurposed or abandoned, however for other Assembly options the operating costs presented are the net cost after an existing Assembly has been removed. The impact of this is the removal of the annual operating costs associated with the existing Assembly that is being refurbished, repurposed or abandoned.

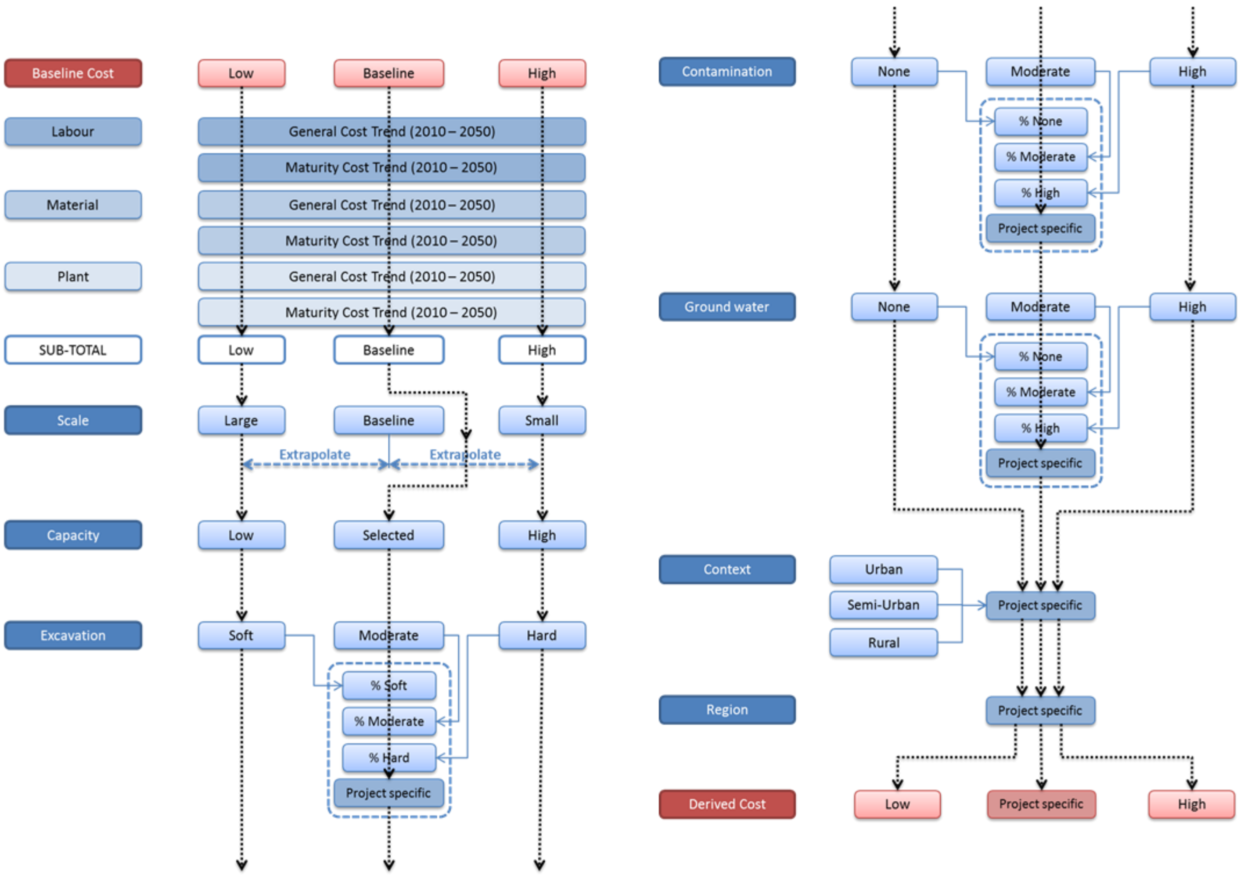


Figure B—2: schematic to illustrate application of Rate Modifiers to Projects

Project Level costs and adjustments

There are a number of costs that are applied directly at Project level. These include project management, preliminaries, contractor overheads and profit, and contingencies. These are added as a percentage mark-up applied to the capital and lifecycle costs incurred in each year of the project once the project Assembly costs have been calculated.

It is also possible to modify costs specifically for the Project. Key adjustments include:

- Cost trends: labour / materials / plant. For each a high, baseline or low rate increase can be selected.
- Ground conditions: excavation difficulty, ground contamination and ground water. For each factor, a percentage can be specified to reflect the proportion of ground conditions expected to be encountered on the Project.

- Optimism bias: There is a demonstrated, systematic, tendency for project appraisers to be overly optimistic. The HM Treasury Green Book[12] advises that, to address this tendency, “appraisers should make explicit, empirically based adjustments to the estimates of a project’s costs, benefits, and duration”. The Infrastructure Cost Model includes the facility for users to apply Optimism bias factors following HM Treasury Green Book guidance. The model includes a default upper and lower bound however this can be adjusted by the user if required.

Project Dashboard

The Project Dashboard presents total Project costs over the specified project life by vector and by cost type (capital and operational) (Figure 8—3) and displays these graphically as a cumulative cash flow (Figure 8—4).

A breakdown of the top five Assemblies and Components in terms of their percentage of total cost is provided to give a view on which aspects of the Project might be deemed critical and potential targets for innovation.

A Net Present Value (NPV) calculation is also calculated. NPV is a useful tool to provide comparative costs to enable comparison of two different projects bringing them back to the same year. Effectively this provides a discounted life cycle cost and will always be negative as there are no revenues. The discount rate set in the model is 3.5% however this can be changed by the user as required (Figure 8—3).

[12] https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

PROJECT DASHBOARD

Ref	20130801 1313
Description	Electricity transmission - East Midlands - test
Owner	HC
Region	East Midlands Region
Context	Rural
Scale	Baseline
Labour cost	Baseline
Materials cost	Baseline
Plant cost	Baseline

PROJECT COSTS IN 2015	P80	P50	P10
Totals	6,980,531,817	5,806,365,013	2,796,428,255
Electricity	4,689,367,012	3,900,692,082	1,879,007,562
Natural gas	-	-	-
Hydrogen	-	-	-
Heat	-	-	-
Preliminaries	702,104,635	584,067,594	281,516,961
Contractors Overheads	269,140,110	223,892,578	107,914,835
Contingencies	565,194,231	470,174,413	226,621,154
PM, Engineering, etc.	746,056,385	620,630,226	299,139,923
Land Costs	8,669,443	6,908,121	2,227,819

TOP 5 ASSEMBLIES

Assembly	% TOTAL
Transmission: HVAC: Overhead: 400kV line [6380 MVA] (New Build)	53.4%
Conversion: HVAC: None: 400kV to 132kV Conversion [670 MVA] (New Build)	36.9%
Transmission: HVAC: Overhead: 275kV line [2600 MVA] (New Build)	7.5%
Conversion: HVAC: None: 275kV to 132kV Conversion [720 MVA] (New Build)	2.2%
#N/A	#N/A

TOP 5 COMPONENTS

Component	% TOTAL
AA12 - Electricity - Overhead - Conductors - Refurb, Repurpose and Abandon: Refurbish 400kV HVAC overhead transmission line	28.0%
AD12 - Electricity - Conversions - On-shore - Refurb, Repurpose and Abandon: Refurbish 400kV to 132kV conversion (two circuits)	27.9%
AA11 - Electricity - Overhead - Conductors - New: 400kV HVAC Overhead transmission line	25.4%
AD11 - Electricity - Conversions - On-shore - New: 400kV to 132kV conversion (two circuits)	9.0%
AA11 - Electricity - Overhead - Conductors - New: 275kV HVAC Overhead transmission line	4.0%

OPEX COSTS DURING PERIOD 2015 - 2074	P80	P50	P10
Totals	3,874,621,240	2,910,646,056	1,812,783,642
Electricity	3,874,621,240	2,910,646,056	1,812,783,642
Natural gas	-	-	-
Hydrogen	-	-	-
Heat	-	-	-

NET PRESENT VALUE AT 2015	Project NPV	Optimism Bias Adjusted	Go there
		Lower	Upper
Totals	3,934,378,815	4,170,441,544	6,531,068,832
CAPITAL COSTS IN 2015			
Electricity	2,216,274,185	2,349,250,636	3,679,015,146
Natural gas	-	-	-
Hydrogen	-	-	-
Heat	-	-	-
Preliminaries	331,826,529	351,736,121	550,832,038
Contractors Overheads	127,200,169	134,832,180	211,152,281
Contingencies	267,120,356	283,147,577	443,419,790
PM, Engineering, etc.	352,598,870	373,754,802	585,314,123
Land Costs	7,284,500	7,721,570	12,092,270
OPEX DURING PERIOD 2015 - 2074			
Electricity	632,074,207	669,998,659	1,049,243,183
Natural gas	-	-	-
Hydrogen	-	-	-
Heat	-	-	-

Figure B—3: Screen shot of Project Dashboard - top section

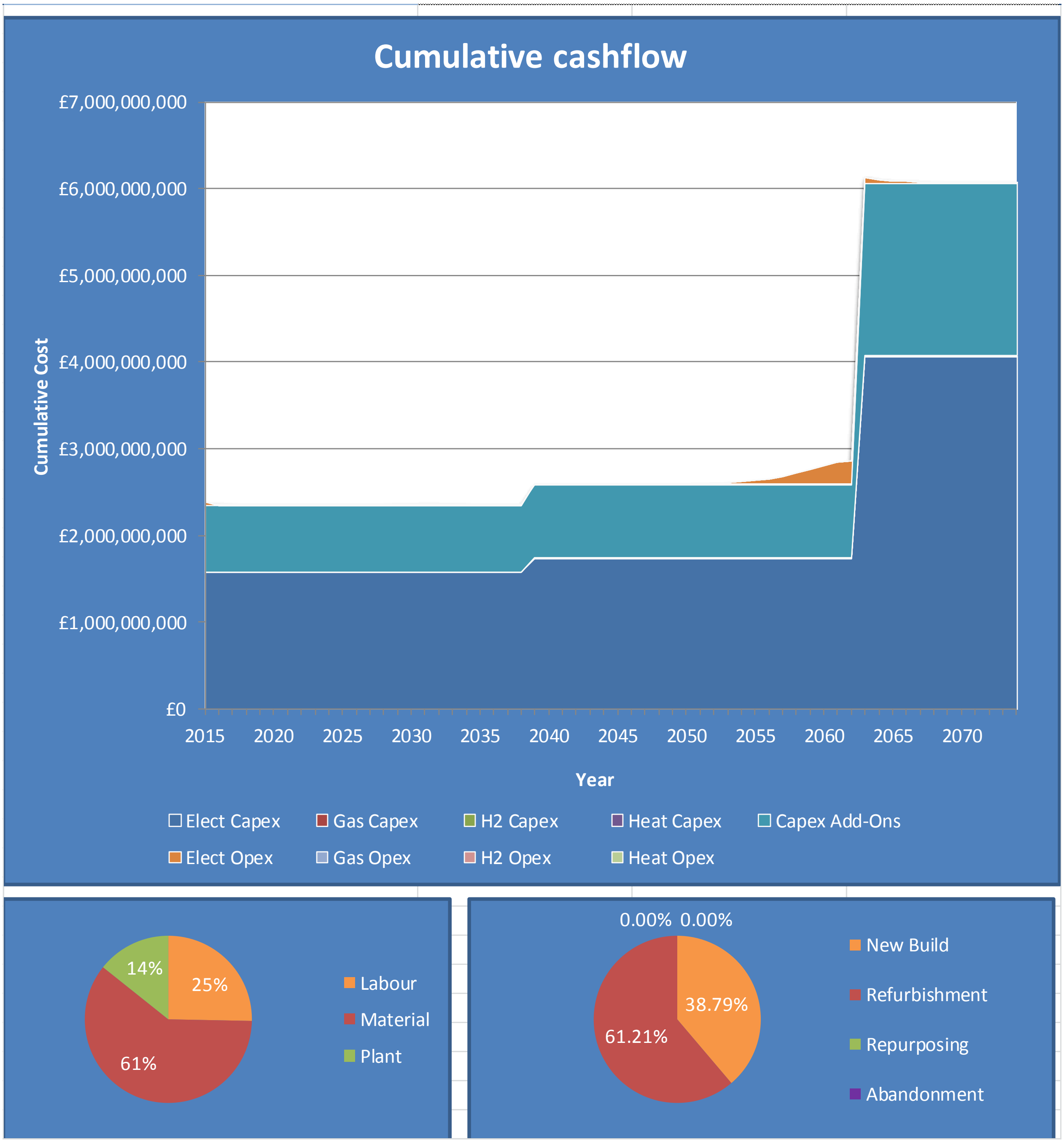


Figure B—4: Screen shot of Project Dashboard - bottom section

Examples of uses

There are a number of ways in which the model can support analysis and decision making in respect of energy projects and strategy. Table 8-1 outlines a variety of potential variations along with an explanation of how the cost model can be used. Limitations in each case are also discussed. Note that for all these, the data can be exported directly from the model (capital and operational costs on an annual basis) for analysis in other models and tools.

Table B-2 Examples of variations which could be informed by the model

	Variation / objective	Model capability	Limitations / factors to consider
1	To compare the cost of implementing a new hydrogen system vs repurposing of existing gas system over any period up to 2050	Two separate Projects need to be input by the user developed based on a 'bill of quantities' for each system. The detail attached to each BoQ should include the dates of the addition or repurposing, and provide any relevant context regarding locality, ground conditions etc. The user can adjust cost rate modifiers as required to match system design assumptions and views of cost trends for each vector. The model will provide cost out turns for each Project which can be compared.	Given that the system is designed outside the model, the results should be straightforward to achieve. There could be issues over the availability of all Assemblies included in the relevant system designs. Either the 'next best' can be selected or new Components and Assemblies can be added. The model will not give any information on relative system efficiency as this is provided separately in the Technical Scoping Tables (see Section 3.3.2).
2	To compare the cost of implementing a new electrical network to support a certain level of demand vs a gas network or heat network to support the same demand	As above, separate Projects can be input to the model based on appropriate BoQs for the system design for each vector.	As above, the results should be straightforward to achieve. Note that the Project functionality does not allow for capital costing only and is set up to provide whole life costs for the specified project period. However data can be readily extracted for analysis elsewhere.
3	To compare the ratio of Opex vs Capex for an electrical network, a gas network and a hydrogen network for supporting a certain level of demand for a particular region within the UK	As above, separate Projects can be input to the model based on appropriate BoQs for the system design for each vector. Opex and Capex are presented separately on the Project dashboard and can be extracted for analysis elsewhere.	The relevant ratio would have to be calculated outside the model. The model will not give any information on relative system efficiency as this is provided separately in the Technical Scoping Tables (see Section 3.3.2).
4	To explore the transitional cost differences of developing an electrical network over a period of 30 years based on small capacity increments vs large scale deployment at strategic intervals	The model allows for input of different Assemblies at different time periods over any period up to 150 years. Thus it can accommodate alternative assumptions regarding the time and scale of deployment. Again, it relies upon the development of suitable BoQs and the relevant time of their deployment. In this case, two separate Projects would be input by the user and the two sets of results compared.	Given that the system is designed outside the model, the results should be straightforward to achieve. There could be issues over the availability of all Assemblies included in the relevant system designs. Either the 'next best' can be selected or new Components and Assemblies can be added. The model will not give any information on relative system efficiency as this is provided separately in the Technical Scoping Tables (see Section 3.3.2).

	Variation / objective	Model capability	Limitations / factors to consider
5	To examine the cost of decommissioning the UK gas network between now and 2050 and determining the optimum cost path to do this.	The user would need to input the quantities of the existing gas assets into a Project. For each Assembly, a start date before the Project start would need to be specified to reflect the age of the asset. The model will then calculate refurbishment and abandonment costs according to the life cycle profile adopted for that Assembly. A bespoke life cycle profile could be added if required.	The model cannot determine an 'optimum' cost pathway as it is not constructed as an optimisation tool in this sense. The user would have to experiment with alternative pathways and compare costs by inputting a new Project for each individually.
6	To explore how the losses of a network determine its feasibility on a regional basis in supporting certain supply and demand infrastructures – do this analysis across different vectors.	Not possible within the model as losses are provided separately as percentages of annual energy flow within the Technical Scoping Tables and would require a better understanding of network configuration and energy flows through the network. A detailed system analysis is required.	Losses are provided as percentages in the Technical Scope Tables attached to the model (see Section 3.3.2).

Appendix C Operational costs

Extract from:

Energy Infrastructure 2050 Final Report, 22 November 2013, available from the ETI

Operational costs

The approach taken to modelling operational costs differs from that used for capital costs in that it is more 'top down' than 'bottom up'. This is primarily due to the level of data available which in turn relates to the way in which assets are managed collectively as networks, and where relevant, to the way in which network operators are regulated. In developing a modelling approach, the aim was to enable an indicative assessment of the impact of investment in new / refurbished or repurposed assets on the overall operating costs of each energy vector.

Investment in new, refurbished, repurposed or abandoned infrastructure will impact operating costs in many ways. These can be summarised as:

- Adding to the asset base and thereby increasing the overall operating cost
- Reducing the asset base and thereby decreasing the overall operating cost
- Changing the asset base and thereby changing the overall operating cost within one or more vectors

Key challenges were:

- To understand what operating costs currently are and, to the extent they are aggregated over a network, how they can be allocated to asset value
- To understand how operating costs might vary over the asset life

The approach to modelling operating costs has been developed from work undertaken by Sweett Group with support from PPA Energy whose full report is included in Appendix G.

Definition of 'operating costs'

Most energy network operators account for their operating costs in similar, if not identical, terms:

- Direct costs - incurred on or close to the network such as, for example, maintenance costs or tree and vegetation management for overhead electricity networks
- Indirect costs, split into:
    - Closely associated costs - those elements which are closely related to the network such as certain IT costs, training, drawing office, maintenance support, etc
    - Business support (not directly linked to assets) - more distant to the network itself but still need to be incurred. This would include, for example, finance, HR, and corporate costs
    - Pass through / uncontrollable costs - substantially outside of the control of the utility. Examples include regulatory licence fees and local government taxation (rates)
    - Depreciation - the non-cash charge to operating costs of previous capital expenditure.

From these categories only direct and closely associated indirect costs are closely proportionate to the scale of infrastructure assets in a region. Over the long term, changes in asset base could affect the other elements of operating costs. It has been assumed that such changes are marginal and outside the level of accuracy of the overall assessment. Further detail is shown in Table C-1 below.

Table C-1: types of direct of closely associated indirect operating costs as extracted from PPA Energy report

<table>
<tr><th></th><th></th><th>Electricity Distribution (DNO)</th><th>Electricity Transmission (TO)</th><th>Gas Distribution (GDN)</th><th>Gas Transmission (GTO)*</th></tr>
<tr><td rowspan="3">Controllable</td><td>Direct Opex</td><td>• Inspection and maintenance (planned and unplanned)
• Trees and vegetation management</td><td>• Inspection and maintenance (planned and unplanned)
• Trees and vegetation management
• Tower painting
• Management of HVDC and New technology</td><td>• Inspection and maintenance (planned and unplanned)
• Work management
• Emergency Repairs
• Independent networks
• Xoserve</td><td>• Inspection and maintenance (planned and unplanned)
• Innovation costs (e.g. IFI)[13]
• Armed guards (at key operational sites)
• Operational property management
• Quarry and loss[14]
• CNI (Critical National Infrastructure) security
• Quasi capex (e.g. costs of decommissioning assets and asbestos removal)</td></tr>
<tr><td rowspan="2">Closely Associated Indirect</td><td colspan="4">• Network Design and Engineering
• Project Management
• Engineering Management and Clerical Support
• System Mapping
• Operational Training
• Vehicles and Transport
• Stores and logistics</td></tr>
<tr><td>• Control Centre
• Call Centre</td><td>• Network policy (inc. R&D)
• Health, Safety and Environment
• Network planning</td><td>• Research and development</td><td>• IT support for systems used to manage network assets
• Gas drawings</td></tr>
<tr><td></td><td>Business Support</td><td colspan="4">• Procurement
• HR
• Insurance
• Finance, audit and regulation
• Corporate</td></tr>
</table>

[13] The opex figures contained in this report are unlikely to include innovation competition funding, e.g. the Low Carbon Networks Fund, as in general they have taken place or will take place after the price control allowances have been agreed
[14] Compensation for landowners for loss of earnings due to pipeline development – under the RIIO framework these costs are treated as controllable

		Electricity Distribution (DNO)	Electricity Transmission (TO)	Gas Distribution (GDN)	Gas Transmission (GTO)*
		• IT & Telecoms • Property Management • Non-Operational Training • CEO costs			
Uncontrollable / pass through		• Licence fee • Network rates	• Licence fee • Network rates	• Licence fee • Network rates • NTS Flat (exit charges) • Interruptions • Shrinkage (losses) • Pension deficit / surplus	• Licence fee • Network rates

*For the GTO a number of costs have moved from "pass-through" or "logged up" to controllable

Approach

Relationship between asset value and operating cost

Analysis of the regulatory accounts of electricity and gas transmission and distribution operators suggests that operating costs comprise between 0.5 and 2.6% of Modern Equivalent Asset (MEA) value[15]. Operating costs as a % of MEA value are significantly higher for gas distribution than for electrical distribution or transmission. Further information on these figures is available from the PPA Energy report in Appendix G.

For the portion of operating costs that are linked to asset management it is assumed that a direct relationship exists between MEA value and operating cost i.e. the impact on operating cost is proportional to the value of new infrastructure as a proportion of the overall MEA value[16] of the infrastructure in a given region.

Recognising that operating costs may vary depending on the nature of the asset, the operating cost model allows costs to be adjusted depending on whether the asset is 'active', such has a transformer or compressor, or 'passive', such as a pipeline or overhead conductor[17].

For the portion of operating costs not directly or closely linked to assets such as corporate administration (IT, HR, etc), planning, reporting and licensing functions, it is assumed that they are not impacted to any meaningful extent by discrete Projects. Although this is reasonable for existing vectors (ie. electricity, gas and heat), when a new vector such as hydrogen is created, these operational overheads would also need to be created to support the asset owner. For hydrogen, an indicative estimate of these overheads is between a third and half of the total operating cost reflecting the current ratio of these costs in gas infrastructure[18].

[15] Ofgem's definition of the Modern Equivalent Asset (MEA) value is: the current replacement value of an asset https://www.ofgem.gov.uk/ofgem-publications/53855/glossary.pdf
[16] The MEA is higher than the network's gross asset value, the latter being based upon historic cost accounting which does not provide a fair means of using value to describe the scale of the asset base.
[17] Analysis of a sample regulatory account showed that the direct operating costs, as a proportion of MEA, are similar for both passive and active asset types. Therefore, the model default is set up to assign equal weighting to both passive and active assets.
[18] This estimate is a simplification of the relationship between direct and indirect operating costs. However, the approach is considered reasonable in the absence of examples of UK hydrogen network of scale and of the regulatory framework that might be applied.

Profile of operating costs over time

A portion of the operating costs of an asset will vary over the asset life. Assuming a flat distribution of operating costs would therefore give a poor reflection of the impacts of replacing existing assets with new assets as the immediate impact could be positive or negative depending on the shape of profile and the age of the asset to be refurbished / repurposed. A classic example of this variation is the 'bathtub' profile whereby failure rates are higher at the start and end of the asset lifecycle with a period of relatively low operating costs in between these periods. However, a range of potential profiles exist with shapes that reflect differing characteristics.

The most significant impact on the operating cost profile of an asset is its failure rate and therefore need for reactive maintenance. The failure rate is assumed to be mainly influenced by the asset type (active or passive).

Whilst there are very many different profiles of operating costs that could be developed, the 'active' and 'passive' options provide reasonable coverage of the different scenarios and are in keeping with the current state of knowledge on specific infrastructure components.

A distribution profile can be used to show how operating costs vary around the average over time. Using the most suitable profile, the direct and closely associated operating costs can be estimated for each year of an asset's life.

Two such profiles have been developed to represent the variation in operating cost over the life of the asset (from 0 to 100% of the defined asset life) (Figure 7—7)[19]. Each profile comprises three 'phases' of operating cost, the early phase of 'infant mortality' where operating cost levels decrease over time, a central period of normal operations where costs are relatively consistent and end of life decay where the rate of failures increases.

The area under each profile curve is taken as the total operating cost for the asset over its life and the operating cost in any given year is determined as a proportion of the total operating cost that is applied in that year.

[19] Note that operating cost profiles ('opex profiles') are assigned at Assembly level along with 'lifecycle profiles' (Section 7.3.4). No operating costs are assigned at Component level.

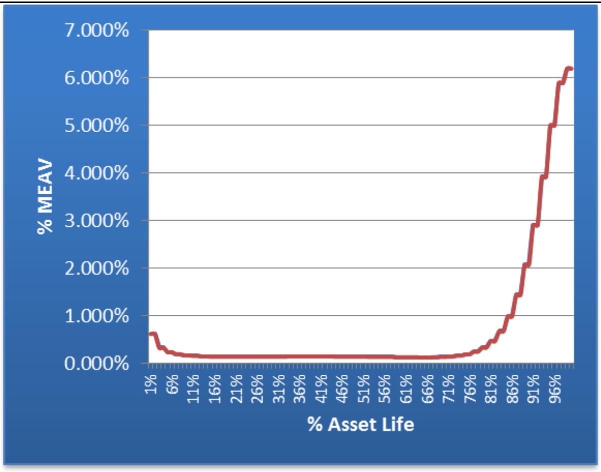
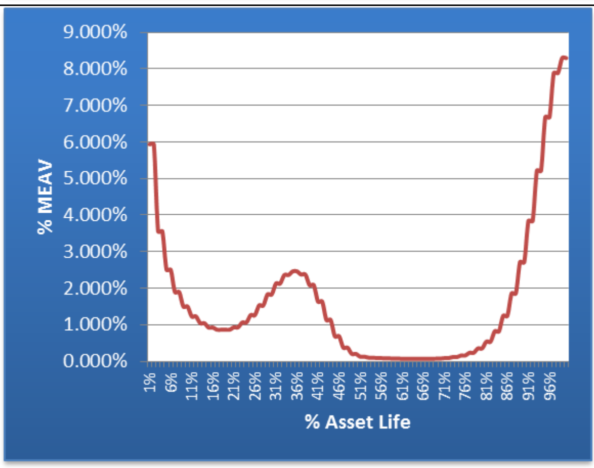
	**Passive Assembly** Minimal infant mortality, due to high level of industry experience and expertise in the installation of these assets. End-of-life decay follows a profile of increasing failure rate until end of life.
	**Active Assembly** Higher infant mortality, due to the active nature of the asset and settling in period required for active components. End-of-life decay follows a profile of increasing failure rate until end of life.

Figure C-1: Operating cost profiles used in the cost model

Table C-2 shows the Assembly types that have been assigned to each profile.

Table C-2: Operational cost profiles as applied within the model to the different infrastructure types of each vector

Vector	Assembly Type	
	Passive	**Active**
Electricity	AC Buried HVAC Buried AC Overhead HVAC Tunnelled HVAC Overhead HVDC Buried HVDC Overhead HVDC Off-shore HVDC Tunnelled	AC Connections AC Conversions HVAC Conversions HVDC Conversions
Gas	Buried pipelines – transmission and distribution Connections	Conversions Storage
Heat	Buried pipelines	Conversions Connections Storage
Hydrogen	Buried pipelines – transmission and distribution Connections	Conversions Storage

Assessing the net impact of a Project on operating costs

The model is structured so as to take into account Projects that may include Assemblies that are new, repurposed, refurbished or abandoned. The net impact of a Project on operating costs is estimated as follows:

- New build Assemblies are assumed to add to the MEA value of the regional network and therefore increase direct and closely associated operating costs by the percentage of MEA value that they represent
- Refurbishment Assemblies assumed to restart the operating cost profile for this portion of the regional network, i.e. if the existing asset is 20 years old, the refurbished asset would be assumed to be 0 years old and the % of its average operating cost that is included in year 1 of the Project adjust accordingly. The change in operating cost might be up or down depending on the age (i.e. the position on the cost profile) of the existing asset
- Re-purposed Assemblies reduce the regional operating cost for the outgoing vector and assumes a New Build profile for the new vector20F20
- Abandoned Assemblies reduce the regional operating cost by the appropriate MEA value as adjusted for the age of the abandoned asset (i.e. its position on the operating cost profile) and therefore the applicable proportion of its average operating costs.

[20] Although there could be some difference in operating costs between new and repurposed assets no data was found to support what these differences would be.

Calculation of Opex Costs

The calculation of opex is based on percentage costs contained in PPA Energy's report included in Appendix G. A summary of reported opex costs as a percentage of MEA value, split into costs attributable to faults / failures and other, general opex costs, is shown Table C-3:

Table C-3: summary of reported opex costs as a percentage of MEA Value from PPA Energy Report (Appendix G)

	Opex as % of MEA Value			**Split**	
	Fault Repairs *FaultOpex%*	Other Opex *NonFaultOpex%*	Total Opex	Direct	Indirect
Electricity Distribution	0.194%	0.602%	0.797%	53%	47%
Electricity Transmission	0.129%	0.400%	0.529%	41%	59%
Gas Distribution	0.406%	0.910%	1.316%	83%	17%
Gas Transmission	0.327%	0.733%	1.060%	79%	21%

In order to determine the proportion of opex attributable to active system elements and passive system elements, the total asset values, for gas and electricity networks, have been summarised from a 2010 report by Cambridge Economic Policy Associates[21]. These network values are summarised in Table C-4, in £ billions, in 2009/10 prices.

Table C-4: summary of MEA Values in 2009/10 prices as extracted from Cambridge Economic Policy Associates, 2010

Vector Group	**MEAV of Active Elements (£bn)**	**MEAV of Passive Elements (£bn)**	**Total MEAV (£bn)**
	$MEAV_{Active}$	$MEAV_{Passive}$	$MEAV_{Total}$
Electricity Distribution	27.0	109.0	136.0
Electricity Transmission	12.0	25.0	37.0
Gas Distribution	2.5	53.5	55.0
Gas Transmission	9.2	52.0	61.2

The totals of probability of failure over the assembly lifecycle (as described previously for passive and active assemblies) are as follows:

[21] Cambridge Economic Policy Associates, The Economic Lives of Energy Network Assets, December 2010.

Active assemblies	*Probability%$_{Active}$*	= 166.6%
Passive assemblies	*Probability%$_{Passive}$*	= 71.6%

The "fault related" and "non-fault" opex factors attributable to active and passive assemblies have been calculated as follows:

For each Vector Group:

1. Electricity Distribution
2. Electricity Transmission
3. Gas Distribution
4. Gas Transmission

Calculation of Fault related annual Opex % for Active Assemblies:

$$OpexCost_{Fault} = MEAV_{Total} \times FaultOpex\%$$

$$OpexCost_{NonFault} = MEAV_{Total} \times NonFaultOpex\%$$

$$ActiveOpexCost_{Fault} = \frac{(MEAV_{Active} \times \Pr obability\%_{Active})}{(MEAV_{Active} \times \Pr obability\%_{Active}) + (MEAV_{Passive} \times \Pr obability_{Passive})} \times OpexCost_{Fault}$$

$$ActiveOpex\%_{Fault} = \frac{ActiveOpexCost_{Fault}}{MEAV_{Active}} \times \frac{100}{1}$$

This principle is repeated for non-fault and passive assemblies, to derive the values given in Table C-5:

Table C-5: Operating costs as a % of MEA Value for active and passive assemblies for each infrastructure type

	Opex Cost as % MEAV			
	Non-Fault Opex		Fault Opex	
	Active Assemblies	**Passive Assemblies**	**Active Assemblies**	**Passive Assemblies**
Electricity Distribution	0.602%	0.602%	0.358%	0.154%
Electricity Transmission	0.400%	0.400%	0.210%	0.090%
Gas Distribution	0.910%	0.910%	0.892%	0.383%
Gas Transmission	0.733%	0.733%	0.635%	0.273%

These Opex% costs are applied to MEAV values of assemblies across the lifecycle period being modelled to derive a total Opex cost per assembly, totalled for the project.

The calculation of annual Opex cost per assembly is as follows:

$$OpexCost_{year.n} = \left(Fault\,\mathrm{Pr}\,obability\,\%_{year.n} \times ActiveOpex\%_{Fault} \times MEAV_{year.n}\right) + \left(ActiveOpex\%_{NonFault} \times MEAV_{year.n}\right)$$

or:

$$OpexCost_{year.n} = \left(Fault\,\mathrm{Pr}\,obability\,\%_{year.n} \times PassiveOpex\%_{Fault} \times MEAV_{year.n}\right) + \left(PassiveOpex\%_{NonFault} \times MEAV_{year.n}\right)$$

Annual Opex cost is further split into Direct and indirect Opex for reporting purposes.

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