ALTERNATIVE HEAT SOLUTIONS

CONVERTING A TOWN TO LOW CARBON HEATING

February 2019

Disclaimer

The report presents the views of the authors and not necessarily the views of the Department for Business, Energy and Industrial Strategy.

Acknowledgements

The project was delivered by a team comprising Ramboll Energy as project lead. We are grateful for the support provided by project partners Turner and Townsend, Brodies LLP, Wardell Armstrong, Geothermal International (GI) Energy and Logan Energy.

Key project stakeholders that provided their time as well as crucial information and advice at key stages of the project were BEIS and Fife Council. We also received valuable information through consultation with Scotia Gas Networks, Kiwa Gastec, Scottish Power as well as a number of technology suppliers.

Ramboll
240 Blackfriars Road
London
SE1 8NW
United Kingdom
T +44 (0)20 7631 5291
www.ramboll.co.uk/energy

CONTENTS

LIST OF FIGURES

LIST OF TABLES

APPENDICES

GLOSSARY OF TERMS

AD	Anaerobic digestion
Advanced thermal treatment plant	Disposal of waste and generation of electricity using thermal treatment technologies.
Allowable Solutions	Proposed mechanism to allow house builders to contribute to off-site carbon abatement measures where all carbon emissions cannot be reduced on-site
Anchor Loads	Large buildings with relatively consistent heat demand such as leisure centres, hospitals or hotels that can act as a significant heat offtaker and 'anchor' heat networks.
APEE	Energy Saving Trust's Advanced Practice Energy Efficiency Standard
ASHP	Air Source Heat Pump
ATES	Aquifer thermal energy storage
bara	Absolute Pressure Unit (bar)
barg	Gauge Pressure Unit (bar)
BCIS	Building Cost Information Service
BEIS	Department for Business Energy and Industrial Strategy
Biofuel	Organic material in either solid, liquid or gas state that is used in a combustion or thermal process to generate energy or synthesis fuels
BSRIA	Building Services Research and Information Association
BTES	Borehole thermal energy storage
Building Regulations	Regulations that ensure building work is carried out in line with defined minimum standards
CCGT	Combined Cycle Gas Turbine
CfD	Contract for Difference
CCHP	Combined cooling heating and power
CHP	Combined Heat and Power
ADE	Association for Decentralised Energy (formerly the – Combined Heat and Power Association) (www.theade.co.uk)
CHPQA	Quality Assurance Scheme for Combined Heat and Power
CIBSE	Chartered Institute of Building Services Engineers
CoP	Coefficient of Performance
C&I	Commercial and industrial
DEC	Display Energy Certificate
DECC	Department of Energy and Climate Change. During the course of the study DECC was merged to become BEIS and for consistency throughout this report refers to BEIS.
Decentralised Energy Systems	Decentralised Energy (DE) is defined by the GLA[1] as "energy which is produced close to where it's used." This means local generation of electricity and where appropriate, the recovery of surplus heat from this generation or other industrial uses for purposes such as building space heating and domestic hot water production. Heat is commonly distributed in District Heating systems, with the heat generated being pumped into homes, usually as hot water, through networks of reinforced pipes. Combining these solutions with heat storage allows the potential for balancing of the heat and power networks.
Delta T (ΔT)	The temperature difference between water flowing in the flow and return sections of the network.

[1] https://www.london.gov.uk/priorities/environment/vision-strategy/london-sustainable-development-commission

Demand management	An automated control of demands within systems, usually non-critical appliances or processes, that provides a network operator with pre-defined authorisations to balance the demand with capacity in the network. The term usually applies in the context of smart energy systems.
DEMaP	Decentralised energy masterplanning programme
DEPDU	Decentralised energy programme delivery unit
Discount Rate	A rate, usually expressed as a percentage, which reduces the real value of an item over time.
District Cooling	A system of distributing cooling to residential and commercial properties through a network of pipes by pumping the energy in a carrier fluid (normally a water/glycol mix)
District Heating	A system of distributing heat to residential and commercial properties through a network of pipes by pumping the energy in a carrier fluid (normally a water or a water/glycol mix)
EHV	Electricity High Voltage
Energy centre	Building that houses heating plant for a district energy scheme
Energy Company Obligation (ECO)	Energy efficiency programme obliging large energy suppliers to deliver energy efficiency measures to domestic energy users
Energy storage	Storage systems that may be capable of retaining energy for short or long periods of time. These systems include fuel storage, multiple forms of thermal and electricity storage some of which are proven but more are being developed
EPC	Energy Performance Certificate
ERF	Energy Recovery Facility
ESCo	Energy Service Company – a professional business providing a range of energy solutions to customers
FiT	Feed in tariff
GFA	Gross floor area
GIS	Geographic Information System
GSHP	Ground Source Heat Pump
GSP	Grid supply point
GWh	Gigawatt hour
Heat Pump	A heating device that can upgrade a low temperature heat source to a higher temperature sink using a refrigeration cycle in reverse.
HNDU	Heat Networks Delivery Unit
HNP	Heat Network Partnership
Horizon 2020	EU funding programme covering research and innovation, including energy
IRR	Internal Rate of Return
JV	Joint venture - a legal entity that is created for a particular financial transaction or series of transactions that involves more than one organisation.
kWe	Kilowatts (electrical)
kWh	Kilowatt hour
kWth	Kilowatts (thermal)
LECs	Levy Exemption Certificates
Linear heat density	Heat density per metre of network (in one direction only) [MWh/m]
LNG	Liquefied natural gas
LZC	Low and zero carbon
Microgeneration	Small scale generation of energy (usually renewable) by a single residential or commercial unit and mainly for self-supply
MSW	Municipal solid waste
MWe	Megawatts (electrical)
MWh	Megawatt hour
MWth	Megawatts (thermal)

Netting Off	Commercial agreement between the generator and their electricity supplier where the generator is both buying and selling electricity the cost of any electricity bought from the supplier is considered to be the net of the value of electricity imported and exported by the generator. (A higher value for electricity sold, may be achieved in this way)
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
Off-gas grid	Properties that are not connected to the gas distribution network – generally this situation occurs in rural areas.
OFGEM	Office of Gas and Electricity Markets
Peaking plant	Heating plant that is in place to meet the peak demand in the scheme
PE	Polyethylene (in particular in relation to pipe systems for gas networks)
PED	Pressure Equipment Directive
PFI	Private Finance Initiative
PPS	Planning policy statement
PSS	Primary sub-station
Private Wire	Electricity from a CHP is not exported to the grid rather provided, under a commercial agreement, directly to customers via privately owned electricity cables between the generator and customer.
PV	Photovoltaic – panels that convert solar radiation into electricity
RHI	Renewable Heat Incentive
RICS	Royal Institution of Chartered Surveyors
RMU	Ring Main Units
RO	Renewable Obligation
ROC	Renewable Obligation Certificate
Safeguarding Direction	Sets out areas where statutory consultation is required on planning applications, allowing planning authorities to avoid new obstacles to strategic developments
SHLAA	Strategic Housing Land Allocation
SHQS	Scottish Housing Quality Standard
SHW	Solar hot water – heated using thermal radiation from the sun
Smart energy systems	A smart energy system integrates hardware and system controls across the network. They require the investment in upgraded network infrastructure, domestic and non-domestic appliances as well as the control systems to allow smart management of the grid. Smart management includes the ability to optimise the use of storage and to implement demand management.
SPV	Special purpose vehicle – a legal entity that is created for a particular financial transaction or series of transactions and to isolate financial risk from one or more lead organisations.
Syngas	Fuel gas mixture consisting primarily of hydrogen, methane, carbon monoxide, and very often some carbon dioxide produced from the thermochemical conversion of biomass.
tphe	tonnes per hour equivalent (steam)
VRF	Variable Refrigerant Flow (type of air conditioning system)
WRAP	Waste and Resources Action Programme
WSHP	Water Source Heat Pump
WWTW	Wastewater Treatment Works
Z Factor	Ratio defining the amount of power reduction in a steam turbine per unit of heat extracted as steam from the turbine

1. TECHNICAL SUMMARY

The purpose of the study is to compare four different alternative, low carbon heating solutions for a typical small to medium sized town in the UK. The town selected for assessment is Cowdenbeath in Scotland from a shortlist of eight towns in Great Britain. The selection was based on a set of assessment criteria to determine which options was closest to the UK average.

A key challenge for the decarbonisation of heat arises in the UK's many small and medium sized towns where (collectively) a large proportion[2] of the UK population lives. The path to decarbonising the heat supply is arguably more challenging here than in larger, urban areas with higher heat density and associated economies of scale - e.g. for district energy schemes. The objective of the research undertaken is to increase understanding of the costs and key cost drivers of different technical solutions for small and medium sized towns. This is intended to generate insights to help focus and prioritise further work on heat decarbonisation approaches. An improved understanding of the cost and carbon reduction performance of different technologies applied to small and medium towns will enable more robust decisions to be made around their development and deployment as both technologies themselves, and their markets (i.e. costs), evolve.

The technology options considered in this study are 100% conversion to:

- Hydrogen boilers combined with electric cooking. The hydrogen is generated from distributed steam methane reformation (SMR) plants with carbon capture and storage (CCS)
- Hybrid heat pumps (HHP), electric heat pumps combined with natural gas boilers and gas cooking
- Electric heat pumps (EHP) and electric cooking
- District heating[3] supplied from biomass and electric heat pumps and electric cooking

These scenarios were selected to provide a technologically diverse range of low carbon heat solutions. The report presents a comparison of cost and carbon emissions between the scenarios. The scenarios can be compared to a business as usual (BAU) scenario which is assumed to comprise the continued operation and lifecycle replacement of gas boilers connected to the gas grid with a mix of gas and electric cooking. The BAU scenario was created assuming no attempts to decarbonise beyond current policy assumptions and was used as a basis of comparison for carbon emissions.

This study involves research into the lifecycle deployment of these options and the development of a technical and economic lifecycle cost model. The underlying cost assumptions in the main scenarios are based on a presumption that for each of the technologies considered a national roll-out happens before or concurrently with the deployment in Cowdenbeath. As a result it is assumed that the cost of technologies have fallen in line with projected cost reductions due to the scaling up of the supply chain and market competition.

---

[2] Based on 2011 census data (National Statistics, 2013) 44.6% of the population live in areas defined as city and town and 9.2% of the population live in areas designated as town and fringe. Of the remainder 36.9% of people live in major and minor conurbations and 9.3% live in areas classified as villages, hamlets and isolated dwellings.

[3] It is important to note that the scenarios considered in this study apply specific technology, however one of the major benefits of district heating is that many alternative sources of heat are compatible to supply into the network.

The findings of this research and the results of this modelling for Cowdenbeath are presented in this report. The following provides a summary of the overall methodology adopted:

- Town selection – criteria, shortlisting and assessment of options for a suitable target town to support the project objectives;
- Model development – developing a techno-economic model to support comparative analysis of the available options and transitioning scenarios;
- Data assimilation – baseline data mapping and business-as-usual forecasting
- Risk Analysis – collaboration with stakeholders and partners to identify key risks to be addressed through model sensitivity analysis;
- Modelling – techno-economic modelling and analysis to generate cost and carbon performance data for individual options and transitioning scenarios.

1.1 Town Selection

The town chosen for the pilot study was selected from a shortlist of options. A series of key criteria and sub-criteria were agreed with BEIS to determine a representative town.

These are described in Table 1.

Table 1: Key criteria selected to classify towns

Key Criteria	Sub-Criteria
Town Demographic	Summary of population age and level of employment activity.
Town Make-up	Describes property tenure[4] and land area usage within the town.
Property Characteristics	Summary of property types and ages present in the town.
Future Development Projections	Details any development/regeneration projections and local development plans.
Local Authority	Details willingness to engage and any heat map data which can be provided by the local authority.
Energy Usage Breakdown	Breakdown of central heating systems present in the town.

For each of the towns considered a sum of the weighted category scores was then calculated in order for an overall comparison of the towns. The weighting analysis was based on the characteristics of the town being similar to the national average.

The results of this analysis are shown in Table 2.

Table 2: Weighting analysis of criteria to select preferred town

	Bicester	Otley	Shipley	Bioquarter	Cowdenbeath	Leith	Leven	Lochgelly & Cardenden
Town Demographic	0.2	0.2	0.2	0.2	0.4	0.3	0.3	0.4
Town Make-up	1.3	1.3	1.5	1.0	1.0	1.5	1.0	1.0
Property Characteristics	0.3	0.4	0.3	0.5	0.2	3.5	0.9	0.2
Future Development Projections	0.5	0.5	1.0	0.5	0.5	0.5	0.5	0.5
Local Authority	0.5	0.5	1.0	0.5	0.5	0.5	0.5	0.5
Energy Usage Breakdown	0.4	0.3	0.4	0.4	0.3	0.6	0.6	0.6
Total Score	3.2	3.3	4.4	3.2	2.9	6.8	3.8	3.1

[4] Data referring to the rate of commercial and residential usage was absent from census tables and will therefore not be used as a comparison between proposed towns.

Based on information provided, Ramboll concluded that the town that meets the selected criteria to the fullest extent was Cowdenbeath. The types of properties present within Cowdenbeath provide a strong representation of the situation throughout much of the rest of the UK.

1.2 Model Development

The technical and economic analysis was developed within an MS Excel-based model. It allows techno-economic comparison (cost benefit) of the generation, infrastructure and customer connection costs for alternative heat supply. The model is supplemented with clearly defined variables (mainly around the supply technology) such that it is relatively simple to make comparison across the financial performance and capital costs for the range of networks for which data is captured. It provides a detailed bottom-up estimate of the capital costs to convert a UK town from natural gas heating and cooking to alternative low-carbon technologies. This is based on a series of defined scenarios and data from publically available data sources to characterise the selected town.

The main indicators of performance that are presented in the results from the model are:

- Technical outputs including annual running hours, heat and electrical production from each plant;
- Breakdown of the lifecycle cost within a cost plan presenting annual capital, operating and replacement (including fuel) costs;
- Discounted net present cost (NPC) of each solution;
- Comparison of NPC against area and linear heat density; and
- Lifecycle carbon emissions and cost of carbon abatement.

The structure is described in a high level Model Map illustrated in Figure 1.

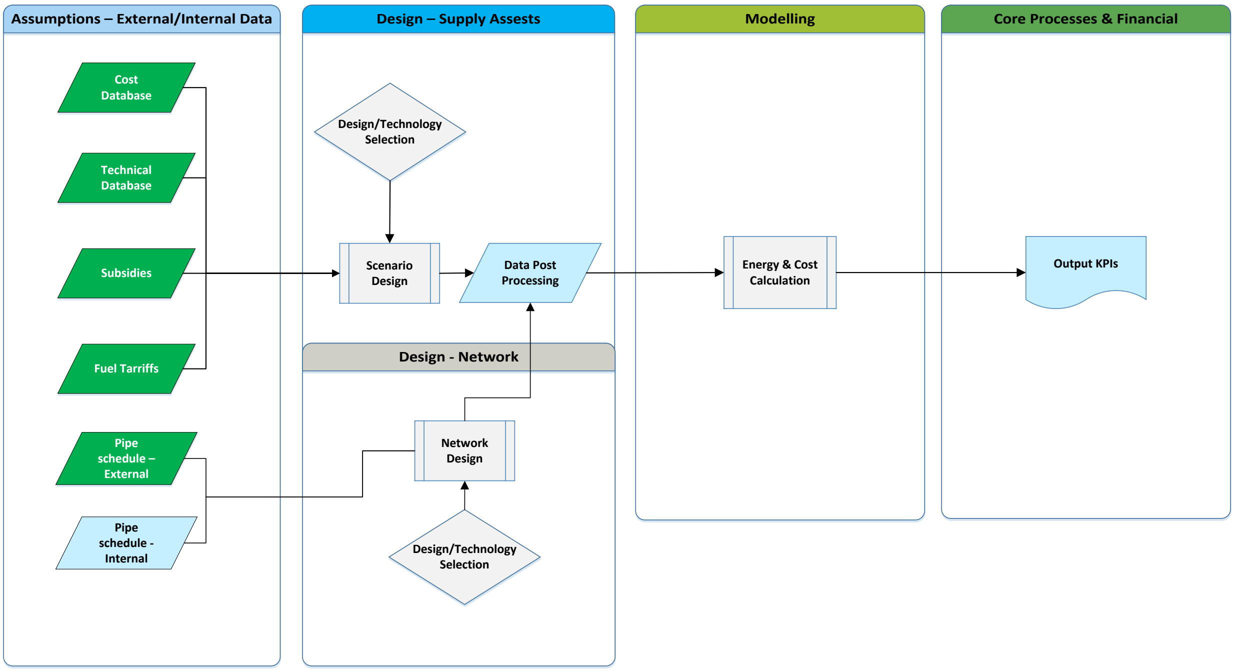


Figure 1: Model map

The model analyses the performance of the selected town on the basis of energy demand data and user inputs relating to the physical infrastructure required. The report provides results for the modelling carried out for the following scenarios:

i) Main scenarios

For the main scenarios, four technology options were considered:

- Distributed hydrogen generated from steam methane reformation (SMR) with carbon capture and storage (CCS) for heating combined with electric cooking
- Hybrid heat pumps (HHP) with gas cooking
- Electric heat pumps (EHP) and electric cooking
- District heating supplied from electric heat pumps and biomass boilers, and electric cooking

ii) Low temperature scenarios

The impact of upgrading the energy efficiency of existing properties was analysed as a future alternative scenario for each of the four technology options. This would enable the use of lower temperature heating systems for each technology, potentially offering further carbon emissions savings.

iii) Pilot scenario

A further scenario was analysed based on a a pilot project that uses hydrogen generated at the Mossmorran ethylene plant located close to Cowdenbeath. The purpose of this scenario is to estimate the costs of direct use of hydrogen from this industrial plant if a local demonstration project were to be developed. This scenario was only modelled for the hydrogen technology option and is therefore not used for comparison with the other scenarios modelled.

For each of the scenarios, the results of the model were presented for the following criteria:

- Total net present cost (NPC[5]) in £/MWh over a 40 year life-cycle
- CO_2 reduction over a 40-year life-cycle.
- Cost per tonne of CO_2 saved

1.3 Data Assimilation

Input data for the model was gathered from a number of different sources including:

- Data on Cowdenbeath provided by Fife Council.
- Data gathered from site visits to Cowdenbeath.
- Data provided by Scotia Gas Network on the existing gas network.
- Data provided from the National Heat Map and Scotland Heat Map on the heat demand for Cowdenbeath.
- Public billing data for heat demand for public buildings.

1.4 Risk Analysis

Through a series of workshops with the project team and local stakeholders, the study investigated the risks associated with national and local deployment of the solutions. This was important as a precursor to the modelling exercise, to as far as possible allow relevant risk factors and sensitivities to be taken into account.

[5] NPC = total present cost of the project after discounting (as distinct from NPV = total present value of profit after discounting)

The following list of key risk categories was identified in early risk workshops by the project team. Each of these categories was expanded through research and further workshops and consultation with stakeholders.

This report provides a summary of the principal risks that were identified.

- Technology barriers
- Regulations and standards
- Planning
- Supply chain and technology availability
- Governance and commercial viability
- Lifecycle economics
- Government and reputational risk

One of the principal barriers assessed in this study was the ability to persuade customers to convert their heating systems. Of all the technologies considered the logistics of converting the town's network from natural gas to hydrogen was deemed to be most significant. This includes installation of suitable hydrogen boilers in individual dwellings. Logan Energy were consulted to provide specialist advice on this technology and provided the necessary input into the model prior to modelling the various scenarios considered.

1.5 Modelling

The model was run for the 9 scenarios identified (4 main, 4 low temperature and 1 pilot).

The main parameters that impact on the model outcomes include:

- Energy demand profiling (both peak and annual) for each option;
- Capital cost for each option (generation/distribution/terminal);
- Running (OPEX) cost for each option;
- Level of electrical grid carbon content;
- Fuel cost for each option;
- Length of operation.

The model is structured to provide a simple user interface with a single page to manage all data input (Figure 2). The model is broken down into a series of stages to describe the relevant data, the technical scenario to be modelled and reporting.

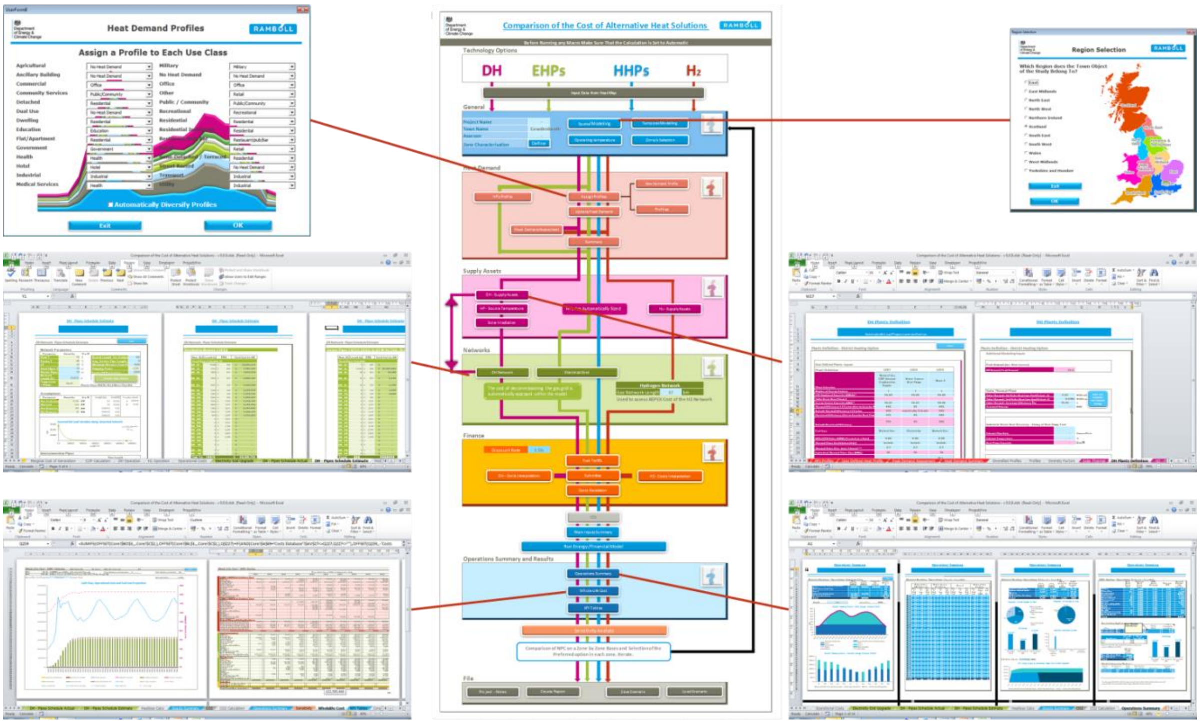


Figure 2: Model user interface

1.6 Main Findings

The outputs of the main scenarios provide an initial assessment of the potential costs of converting Cowdenbeath in conjunction with a national scale transition to low carbon heating systems.

When considering the costs of the scenarios presented it should be noted that the analysis uses a plausible set of assumptions for each technology scenario rather than choosing assumptions that ensure parity between scenarios. As a result, different scenarios achieve different levels of carbon reduction and therefore direct comparison between costs should bare this in mind. The level of CO_2 savings achieved in each scenario are therefore a direct result of the assumptions made in the model for each technology option. This does not represent the maximum potential CO_2 reduction that each scenario could achieve.

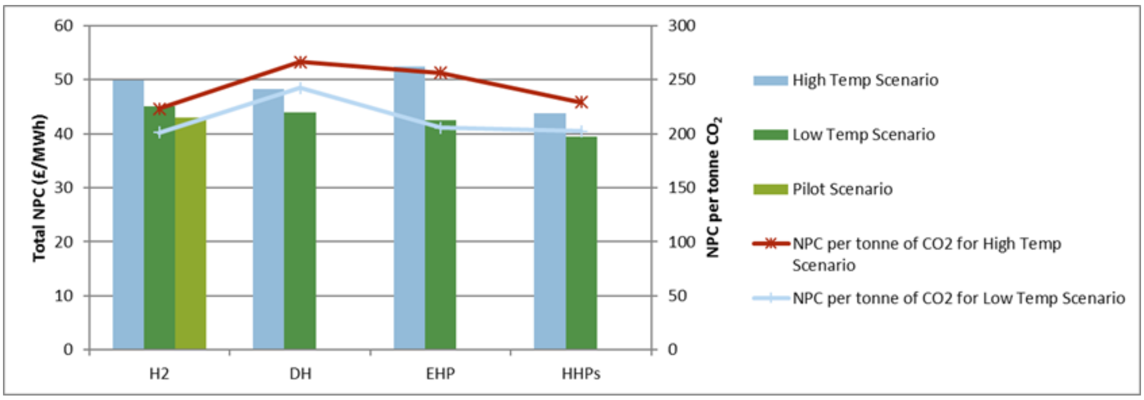


Figure 3: Comparison of NPC and cost of CO_2 emissions reductions for technology options under different scenarios. High and Low temperature refer to the heat distribution temperature in buildings. The Pilot scenario represents the estimate cost of a hydrogen demonstration project.

The lifecycle costs for all technologies presented (Figure 3) show a ~25% difference between the highest and least cost scenario analysed with the model. This figure illustrates the Net

Present Cost (NPC) as bars on the left axis, which represents the discounted total lifecycle cost of the scenario over a 40 year time horizon. The line chart presented on the same figure illustrates the NPC per tonne of CO_2 saved from the Business as Usual (BAU).

The main scenarios (high temperature) are also compared to an alternative scenario in which low temperature heat distribution in buildings and higher levels of thermal insulation are assumed. The comparison of the main scenarios with the low temperature scenarios (Figure 3) indicates that the investment in fabric energy efficiency and low temperature systems results in lower lifecycle costs for all technology options. EHPs appear to recognise the greatest benefit from a conversion to low temperature heating in properties. The benefit of operating at low temperature is due to the reduced energy consumption from lower energy losses over the life of the project. Heat pumps, in addition, benefit from a higher efficiency when delivering low temperature. District heating benefits from lower heat losses from pipes when distributing lower temperatures.

Increased efficiency of heat distribution systems in individual buildings requires a higher CAPEX but offers whole life carbon and cost benefit across the energy system with the potential to offer a reduced cost of energy supply to consumers.

The report also presents the uncertainties with establishing cost forecasts over a 40 year lifecycle, therefore the results should be considered in conjunction with sensitivity analysis presented in Section 7.2, in which some of the parameters that drive the costs of each technology are illustrated.

An assessment of some of the key barriers and risks associated with the implementation of each of the options was also carried out. For consumers key issues were high upfront costs of new heating systems which may need to be financed under new business models. The public perception and lack of awareness of some of the technologies creating a need for widespread public engagement and consumer protection. Technical risks identified include the lack of appropriate skills throughout the supply chain, and the required capacity to deliver a transition of this scale; as well as the compatibility of some technology options with the current UK building stock. The key risks associated with policy and regulation are stability of public policy and the timescales associated with delivering such a significant infrastructure programme, which is true of all options considered.

The cost of a utilising hydrogen from the nearby Mossmoran Ethylene plant was estimated for the purposes of a theoretical demonstration project. The lifecycle cost was estimated to be £42.9/MWh for the project. This assumes that hydrogen can be taken directly from the Ethylene plant without further investment in infrastructure.

Wider Conclusions

The range of costs presented illustrates the inherent challenges in modelling scenarios with technologies that are influenced by the entire energy system. The complexity involved in understanding the full impact of all of these variables makes it difficult to draw clear conclusions on the relative benefits of each solution at a town level.

Local natural resources and infrastructure will influence cost of heat production and therefore the least lifecycle cost solution may vary due to local circumstances. The report concludes that there is a requirement to standardise a methodology for strategic planning of energy solutions that reflects these differences.

The cost of financing the options will influence the relative affordability of each of them and may become one of the determining factors in any preferred implementation strategy. Similarly, the differing delivery structures and approach to financing most suited to each of the scenarios may influence the degree of associated financial risk and therefore the willingness to invest in each of the options. For example, although there may be benefits in terms of the overall cost to society of implementing solutions with lowest whole life costs, these options may have higher up front capital costs and may therefore be more difficult to finance under a market based approach to delivery[6].

1.7 Suggested further research

The report presents a series of results and is supported by a lifecycle technical and economic model. There are a number of assumptions that are based on limited evidence. Further evidence on these should be prioritised to improve the robustness of the model. These include:

- The upgrades required to buildings to enable low temperature heating systems and the capital cost of these upgrades
- Costs associated with decommissioning the gas grid
- Future trajectory of all technology costs
- Capital costs associated with the hydrogen scenario, in particular hydrogen boilers, meters, generation in SMR and CCS.

Sensitivity analysis was carried out on a number of key parameters, however the model allows for further research and study into the effect of varying uncertainty:

- Future fuel prices for all fuels, notably electricity and gas;
- Heat generation plant capital costs where limited commercial plants exist;
- Heat generation plant operation and maintenance costs including cost of hydrogen fuel;
- Future technology cost projections;
- Cost of district heating network; and
- Costs for conversion of boiler plant to heat interface units and conversion of appliances to electricity.

[6] If proposed as the mechanism for roll out of the scenario.

2. INTRODUCTION

Ramboll was appointed by the Department of Energy and Climate Change (DECC) to undertake this study into alternative heat solutions for a typical medium sized town in the UK. During the course of the study DECC was merged to become Department for Business, Enterprise and Industrial Strategy (BEIS) and for consistency throughout this report refers to BEIS.

2.1 Background

The UK Government has taken a number of steps to limit the UK's emissions of greenhouse gases through legally binding targets, both now and in the future. As part of this The Climate Change Act (UK Government, 2008), commits the UK to reducing emissions by at least 80% in 2050 from 1990 levels (UK Government, 2015).

Tackling climate change requires action across industrial, energy supply, buildings and transportation sectors. Roughly half of the final energy consumed in the UK is used to provide heat (DECC, 2011). Around three quarters of the energy used by households is for space and hot water heating, over 80% of which is met using natural gas-fired boilers. Therefore if the UK is to remain on a path consistent with avoiding the damage to the economy, society and public health we need to virtually eliminate greenhouse gas emissions from our buildings by 2050, and to see deep reductions in emissions from industrial processes.

While natural gas will supply the majority of our heat demand well into the 2020s, cutting emissions from buildings and industry means taking the carbon out of heat in the longer term, managing demand through energy and resource efficiency, and replacing fossil fuels with low carbon alternatives. The role of natural gas as the primary fuel for heating will therefore need to decline significantly over the period and a transition to other low carbon heating solutions will be required on an unprecedented scale.

A key challenge arises in the UK's many small and medium sized towns where (collectively) a large proportion[7] of the UK population lives. The path to decarbonising the heat supply is arguably more challenging here than in larger, urban areas with higher heat density and associated economies of scale - e.g. for district energy schemes. Research to identify and increase understanding of the most cost-effective solutions for small and medium sized towns could therefore generate important insights to help focus and prioritise future carbon reduction strategies. An understanding of the likely cost and carbon reduction performance of different technologies applied to towns will enable more robust decisions to be made around their development and deployment as both technologies themselves and their markets (i.e. costs) evolve.

This research aims to characterise technology solutions for the selected town and identify costs, practical constraints and challenges associated with each of the technology solutions considered.

[7] Based on 2011 census data (National Statistics, 2013) 44.6% of the population live in areas defined as city and town and 9.2% of the population live in areas designated as town and fringe. Of the remainder 36.9% of people live in major and minor conurbations and 9.3% live in areas classified as villages, hamlets and isolated dwellings.

2.2 Objectives of the Study

The purpose of the study is to provide a bottom up estimate of the costs of four different alternative low carbon heating solutions to a typical small to medium town in the UK and to compare their performance. It looks at the following list of technology options[8]:

- Distributed hydrogen generated from steam methane reformation (SMR) with carbon capture and storage (CCS) for heating combined with electric cooking
- Hybrid heat pumps (HHP) with gas cooking
- Electric heat pumps (EHP) and electric cooking
- District heating[9] supplied from biomass and electric heat pumps and electric cooking

2.3 Approach

The technical and economic analysis considers design solutions for 100% switch to the options listed for Cowdenbeath, Scotland which was the chosen development area. This analysis is conducted within a model developed specifically for the comparison of the cost of the four technology options listed above.

This report presents the analysis results for a primary scenario involving the deployment of the technologies concurrently with a national roll-out of the technologies. This illustrates the costs associated with significant uptake and cost benefits from economies of scale within supply chains. The scenario also presents the relative carbon emissions reduction for each solution and the costs associated with this reduction.

The report presents and discusses the sensitivity of modelling results to key parameters. It also discusses two principal alternative scenarios to show:

- The impact of implementing a higher level of energy efficiency improvements to individual properties on the lifecycle cost of the four technology options.
- The costs of a stand-alone pilot Hydrogen project in Cowdenbeath – i.e. where economies of scale from wider roll-out do not apply (CCS is not included);

The technical and economic analysis was developed within an MS Excel-based model. It allows techno-economic comparison (cost benefit) of the generation, infrastructure and customer connection costs for alternative heat supply. The model is supplemented with clearly defined variables (mainly around the supply technology) such that it is relatively simple to make comparison across the financial performance and capital costs for the range of networks for which data is captured.

The model includes a series of built in assumptions and calculations, however the user is required to introduce data into the model in the form of heat demands. The main data for Cowdenbeath was provided by Fife Council and included data from the Scotland Heat Map as well as building characteristics and records of investment in energy efficiency measures. The user interface also requires projections of timescales, physical and technical parameters of the future energy infrastructure.

The model makes a series of calculations of the business as usual and alternative heat solutions to generate the following cost parameters that are used in a lifecycle cost model:

---

[8] For the options it is assumed that all houses will use electric cooking, with the exception of hybrid heat pumps which are assumed to continue to use a mix of electric and gas cookers.

[9] It is important to note that the scenarios considered in this study apply specific technology, however one of the major benefits of district heating is that many alternative sources of heat are compatible to supply into the network.

- Capital cost
- Operating and maintenance costs
- Energy cost forecasts
- Carbon emissions

The model then provides a series of technical and economic outputs to illustrate the results. The structure is described in a high level Model Map illustrated in Figure 4 below:

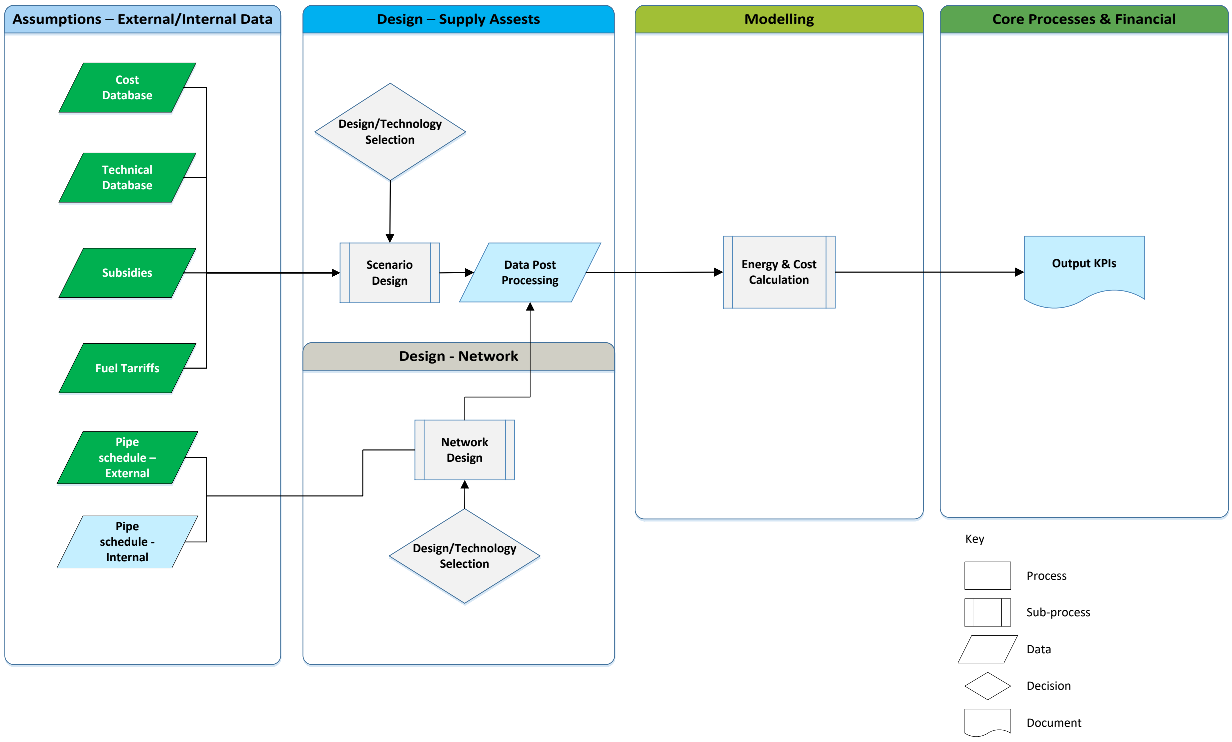


Figure 4: Model Map

3. TECHNOLOGY OPTIONS, RISKS AND BARRIERS

The technology options that are considered in this report are briefly introduced in the following sections. The assumptions used in the modelling of the selected scenario are further explained in Section 5.

3.1 District Heating

District heating networks comprise centralised generation of heat at an energy centre that distributes hot water in a network of insulated pipes to customers. The heat can be produced by a low carbon heat generation technology combined with thermal stores. In the modelled scenario the main heat plant comprises biomass boilers and heat pumps with natural gas boilers providing back-up and peak heat generation. The customer receives heat from the network via a heat interface unit that supplies the customer heating and hot water systems.

The district heating scenario assumes that the local gas network becomes redundant and is largely decommissioned and all customers use electric ovens and hobs for cooking. The gas network / connection is retained to supply the energy centre only and not for distribution throughout the town. Alternative options for back-up and peak heat could be used as an alternative to gas, however the modelling in this study assumes gas boilers.

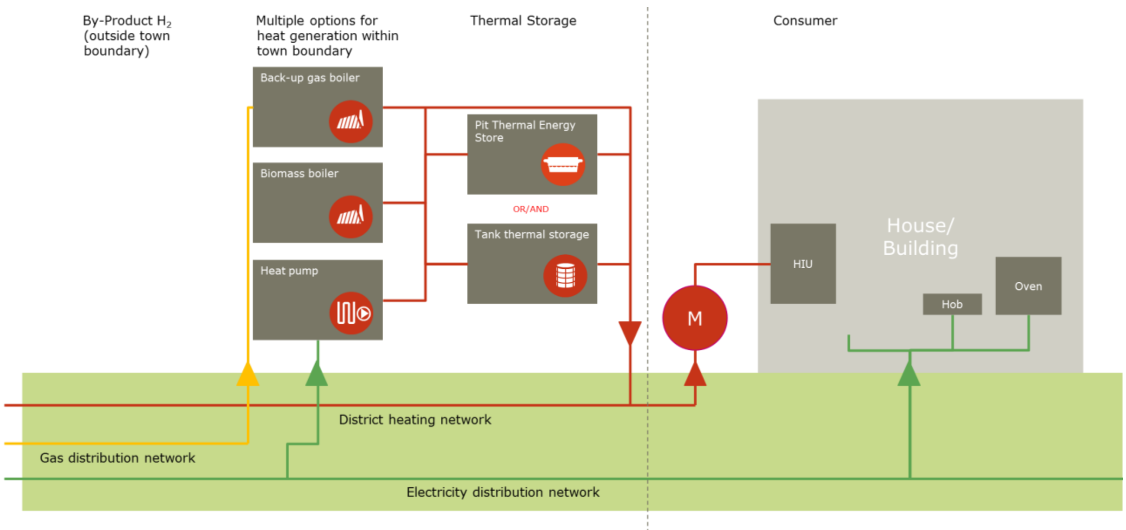


Figure 5: Illustration of the district heating scenario with electricity supply retained to consumers and gas network in the town decommissioned.

3.2 Electric Heat Pumps

The electric heat pump scenario (EHP) involves replacement of all customer heating plant with EHPs. This would necessitate upgrades to electricity supply infrastructure and decarbonisation is achieved through progressive decarbonisation of the grid. The analysis allows for distribution network upgrades but no capital cost is included for electricity transmission network upgrade.

The EHP scenario assumes that the gas network becomes redundant and is largely decommissioned and all customers use electric ovens and hobs for cooking.

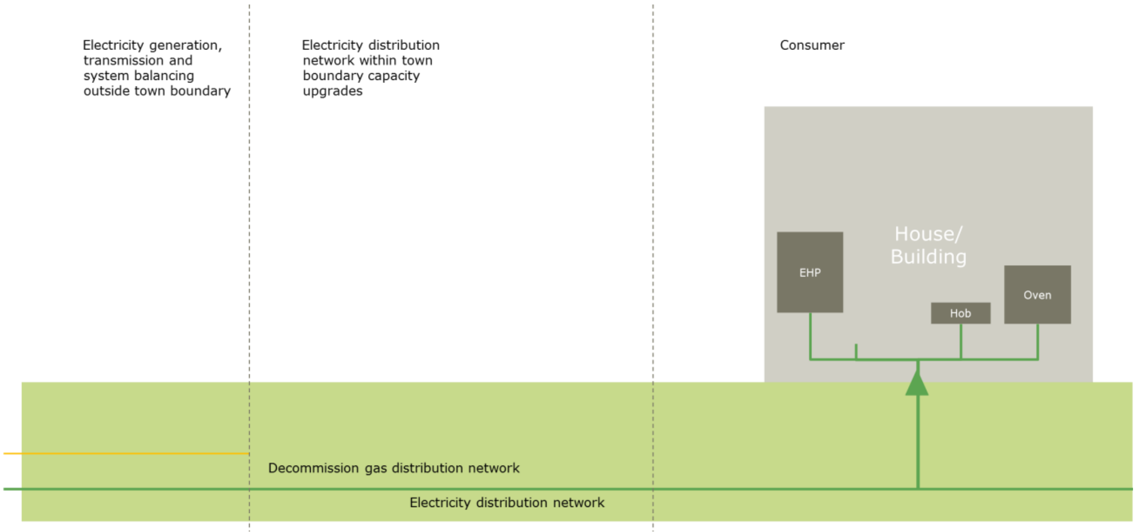


Figure 6 : Illustration of the electric heat pump system with electricity supply upgraded within the town and gas network decommissioned.

3.3 Hybrid Heat Pumps

The hybrid heat pump scenario (HHP) involves replacement of all customer heating plant with HHPs. The hydrid option uses mains gas rather than electricity to provide back-up / peaking during peak periods. This would necessitate upgrades to electricity supply infrastructure and decarbonisation is achieved through progressive decarbonisation of the electricity grid[10]. The analysis allows for distribution network upgrades but no capital cost is included for electricity transmission network upgrade. The gas network continues to operate with gas storage achieved through line packing.

The HHP scenario assumes that the gas network remains and customers continue to use a combination of gas and electric ovens and hobs for cooking.

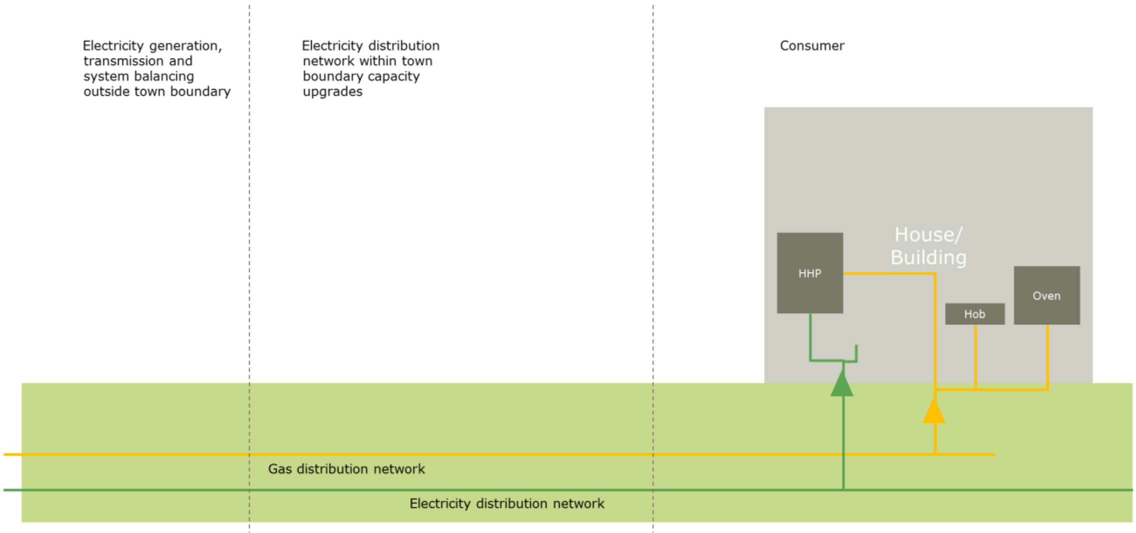


Figure 7 : Illustration of the hybrid heat pump system with electricity and gas supply retained to consumers.

[10] Partial decarbonisation of the gas grid is potentially feasible through biomethane injection, however this is not modelled in the study.

3.4 Distribution of 100% Hydrogen in the Gas Grid

The scenario presented in the report is based on Hydrogen distribution in the existing gas transmission and distribution network. Hydrogen can be generated by electrolysis or SMR at large industrial scale at centralised plants. The modelling apporoach in this report assumes Steam Methane Reformation (SMR). Hydrogen storage capacity can be provided within line packing within national grid infrastructure and in large centralised underground storage. No local storage is therefore assumed.

Carbon capture and storage is included at the SMR plant to provide low carbon hydrogen.

The assumption for the hydrogen scenario is that catalytic hydrogen cooking equipment will not compete on performance or cost and all customers use electric ovens and hobs for cooking. Direct heating from burning hydrogen is not considered suitable due to the flame temperature.

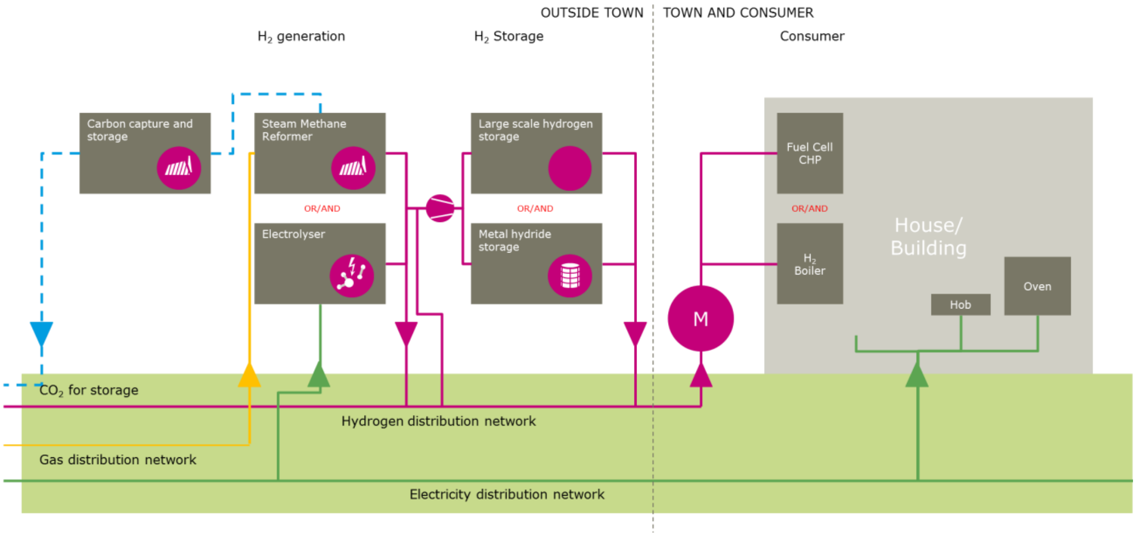


Figure 8: Illustration of the 100% hydrogen system with hydrogen generated with CCS and hydrogen storage and using national gas grid for hydrogen distribution.

3.5 Summary of Technology Options

Table 3 sets out the assumed configuration of the heat supply system that is adopted in the modelling of the options.

The implementation of all the respective solutions considered requires major infrastructure investment and changes to customer systems.

Table 3 : Description of elements of the energy system for each technology scenario

	DH	EHP	HHP	H2
Generation	Energy Centre comprising electric heat pump, biomass boiler and peaking gas boiler combined with thermal stores. Cost of generation included in the CAPEX costs of the project. Carbon emissions associated with primary fuel applied.	Not specifically considered – electricity supply will be from the DNO infrastructure at wholesale electricity price. The grid is assumed to progressively decarbonise according to BEIS forecast.	Not specifically considered – electricity supply will be from the DNO infrastructure at wholesale electricity price. The grid is assumed to progressively decarbonise. Natural gas assumed to be provided at wholesale price through existing infrastructure.	Hydrogen generated by SMR at large industrial scale outside the town boundary, production and CAPEX cost of generation accounted for as a levelised cost for hydrogen supplied to the town.
Storage	Thermal storage included in DH scenario based on 3 hours of storage at full LZC capacity.	No electricity storage capacity included.	No electricity storage capacity included. Gas storage at network level including line packing.	Hydrogen storage capacity assumed to be provided within line packing within national grid infrastructure no local storage assumed.
CCS	Not included	Not included	Not included	Carbon capture accounted for within the levelised cost for hydrogen. Storage and sequestration of CO_2 accounted for separately.
Transmission	No cost included for electricity transmission network upgrade	No cost included for electricity transmission network upgrade	No cost included for electricity transmission network upgrade	No cost included for gas transmission network upgrade
Distribution (within town)	Cost applied in model for district heating network installation and model estimates heat losses in network.	Cost applied in model for electricity distribution network upgrade	Cost applied in model for electricity distribution network upgrade	No cost required for gas network upgrade. A cost is included for switching of gas network from natural gas to hydrogen.
Customer Interface	Heat interface unit and fabric/heating system upgrade if required under low temperature scenario Electric ovens and hobs	Heat pump cost and fabric/heating system upgrade if required under low temperature scenario. Electric ovens and hobs used.	Heat pump cost and fabric/heating system upgrade if required under low temperature scenario. Electric ovens and hobs used	Hydrogen boiler cost and electric ovens and hobs

3.6 Barriers and Risks

The study investigated, through a series of workshops with the project team and local stakeholders, the risks associated with the national and local deployment of the solutions.

The following list of key risk categories was identified in early risk workshops by the project team. Each of these categories was expanded through research and further workshops and consultation with stakeholders.

The principal risks identified for each of the technology options were identified to be related to consumers, commercial, technical, policy and regulation. The risks are discussed in the following sections. These are the risks that were deemed to be most significant and the full assessment of risks was not limited to these issues.

3.6.1 Consumers

Subject	Risk item	Description and discussion of mitigation measures
Cost	High cost of investment in network infrastructure and changes to individual customer heating systems	All solutions require investment at different levels. These costs would have to be borne by the general public and businesses through either direct cost to consumer, utility charges or taxation.
Customer protection	Any national roll-out may not provide the same levels of price and service protection to consumers as prevailing conditions.	The regulation of energy supply provides price protection for gas and electricity but may need to be extended for DH. Solutions all rely on utility networks and operation and maintenance services on consumer units.
Public perception	Negative experiences in individual projects could result in a poor public perception and negative political impact.	Negative experiences for example based on safety, disruption, performance, value for money, customer protection and long term reliability. The solutions selected require careful planning, consultation and communication. This communication will need to ensure that customers are well educated and trained in the use of systems.
Freedom of customer choice	Any national policy on a widespread roll out of solutions could have the consequence of limiting the freedom of customer	Lack of freedom may affect customer uptake to solutions – politically negative since it is perceived as being forced

	choice.	upon the country.
Uptake of solutions	Solutions presented assume that they are adopted at a national scale and this will require incentivisation and/or enforcement.	Enforcement of solutions would impact of freedom of choice (above). The consequence of optional uptake could be high infrastructure costs being incurred with lower than expected additional revenue, poor economic performance and knock on implications on the quality of service.
Public knowledge	The national rollout of energy efficient and alternative heat solutions will require a change of consumer behaviour. Training in efficient use of heating systems is required for first owner and handed on at transfer of ownership.	The implementation of solutions will change how customers interact with heating systems and likely to be disruptive. Communication and stakeholder management are essential. Properties will change hands and it would be appropriate to ensure that communication and training in new systems extends to the new property owners.

3.6.2 Commercial

Subject	Risk item	Description and discussion of mitigation measures
Investment and Ownership	Finance to invest in the construction, ownership and operation of projects is a significant barrier.	The return on investment in infrastructure for the deployment of solutions at a national scale requires high capex and long payback. There may be a lack of appetite for investment by public and private sector
Future fuel prices	Energy costs are a significant driver of whole life cost and the forecast for energy prices is uncertain and creates a challenge to the selection of the most	The whole lifecycle cost is sensitive to gas, electricity and other fuel prices which will impact on the preferred scenario compared to BAU. This may require

Subject	Risk item	Description and discussion of mitigation measures
	economically advantageous individual scenarios over the lifecycle of the investment.	a robust and standard approach to energy planning and associated cost assumptions.

3.6.3 Technical

Subject	Risk item	Description and discussion of mitigation measures
Skills	Lack of experienced installers, operation and maintenance staff for systems under a national roll out.	Large scale adoption of technologies expected to be affected by a skills shortage
Supply chain	The technical solutions considered in this study are not widely prevalent, however they are becoming more common. To deliver a national roll out supply chains will need to expand.	Supply chains will need to expand in UK to support a national roll out to supply equipment for installation and spare parts for ongoing O&M.
Compatibility	Existing heating systems may not be compatible and a significant programme of building retrofits may be required/beneficial	The report provides evidence that installation of energy efficiency measures delivers lifecycle economic and carbon benefits. These measures also make buildings more compatible with alternative heating systems that have to operate at lower temperatures. This would require energy retrofit to current building stock to become a strategic national priority
Sustainability of heat generation, transmission and	Technology selection requires a switch of energy vector from	Natural resources, fuel supply chains and infrastructure will need

Subject	Risk item	Description and discussion of mitigation measures
distribution	natural gas to alternative sources of energy and this will have an impact on the natural resources, fuels and infrastructure required to supply at national scale.	to be able to sustain a national change to the energy system which will require investment. • EHP and HHP will require major investment in electricity networks as well as increased electricity generation capacity; • Hydrogen requires investment in generation plants, CCS and switchover of gas grid to hydrogen; and • District heating requires major investment in energy generation and pipe networks.
Impact of transition to low carbon of other energy system solutions	The UK climate change targets require decarbonisation across electricity, heat (including industry), cooling and transport sectors. There are expected to be synergistic benefits from making technology decisions based on consideration of the whole energy system rather than dealing with these in isolation.	The alternative heat technologies considered in this study convert alternative energy vectors (hydrogen, electricity, gas, biofuels) to heat. These energy vectors can be compatible and offer economic and/or carbon benefits for storage or energy generation for other sectors. This requires consideration of the sustainability of technical solutions for the whole energy system, including smart systems, energy balancing and storage.

3.6.4 Policy and Regulation

Subject	Key item	Description and discussion of mitigation measures
Policy stability 	Stability of energy policy is essential to provide the long term guarantees required for investment in renewable heat infrastructure at national scale.	1. The risk to government through a perceived lack of commitment, where major policy changes affect anticipated projects. 2. Impact on stakeholders, e.g. on a developing supply chain, or on the ability of projects to attract finance. 3. Impact of delays caused by changes in direction, or speed of implementation will be less.
Timescales 	The timescales for development of supporting legislation and policy represent the critical path for the project.	The timescales for upgrading the electricity network capacity assume that the planning has taken place during the price control period for electricity and gas network investment (RIIO). These timescales would need detailed planning with the TNO and DNOs. The timescale for district heating assumes that amendments to national planning policy are complete before the start of a project development process. The delivery period for district heating over 4 years is indicative and in practice this deployment of district heating to a whole town may take a shorter or longer period.

4. ENERGY MAPPING AND DEMAND ASSESSMENT

4.1 Town Selection

A pilot town was selected from a shortlist of options that meet the requirement to assess relative cost competitiveness and other practical issues around converting a UK town of 10-15,000 population from its existing natural gas heating. A series of key criteria were agreed with BEIS to determine a representative town. Data for the characteristics of towns was gathered using both 2011 census data and information provided by local authorities. Several key criteria have been selected and are based on a series of sub-criteria in order to make an effective comparison between the towns as described in Table 4.

Table 4 : Key criteria selected to classify towns

Key Criteria	Sub-Criteria
Town Demographic	Summary of population age and level of employment activity.
Town Make-up	Describes property tenure[11] and land area usage within the town.
Property Characteristics	Summary of property types and ages present in the town.
Future Development Projections	Details any development/regeneration projections and local development plans.
Local Authority	Details willingness to engage and any heat map data which can be provided by the local authority.
Energy Usage Breakdown	Breakdown of central heating systems present in the town.

For each of the towns considered a sum of the weighted category scores was then calculated in order for an overall comparison of the towns. A scoring table is shown in, where low numbers indicate a strong correlation between the data collected for the town and an average figure for the United Kingdom. A traffic light system was used to illustrate the performance of towns.

Table 5 : Weighting analysis of criteria to select preferred town (smaller figure is more representative of UK average)

	Bicester	Otley	Shipley	Bioquarter	Cowdenbeath	Leith	Leven	Lochgelly & Cardenden
Town Demographic	0.2	0.2	0.2	0.2	0.4	0.3	0.3	0.4
Town Make-up	1.3	1.3	1.5	1.0	1.0	1.5	1.0	1.0
Property Characteristics	0.3	0.4	0.3	0.5	0.2	3.5	0.9	0.2
Future Development Projections	0.5	0.5	1.0	0.5	0.5	0.5	0.5	0.5
Local Authority	0.5	0.5	1.0	0.5	0.5	0.5	0.5	0.5
Energy Usage Breakdown	0.4	0.3	0.4	0.4	0.3	0.6	0.6	0.6
Total Score	3.2	3.3	4.4	3.2	2.9	6.8	3.8	3.1

Based on information provided, Ramboll concluded that the town that meets the selected criteria to the fullest extent was Cowdenbeath. As seen from Table 5, the town recorded the lowest score in the study which is a result of the characteristics of the town being similar to the national average. The types of properties present within Cowdenbeath provide a strong representation of the situation throughout much of the rest of the UK. A summary of the characteristics of Cowdenbeath are presented in the following Tables.

[11] Data referring to the rate of commercial and residential usage was absent from census tables and will therefore not be used as a comparison between proposed towns.

Table 6 : Town demographics based on Scottish National Statistics 2014 data.

Indicator	Units	Value
Population		13677
Age of pop		
aged under 18	%	17.77
between the age of 18-65	%	60.26
aged over 65	%	21.97
Employment Activity		
economically active	%	66.4
employed part-time	%	14.8
employed full-time	%	37.6
self-employed	%	5
unemployed	%	6.7
employed whilst being a full-time student	%	1.6
economically inactive	%	33.6
unemployed whilst being a full-time student	%	0.7
retired	%	17.2
students	%	3.4
looking after home or family	%	3.6
long-term sick or disabled	%	7.2
Other	%	2.3
Property Tenure		
own a property	%	56.5
rent property from council	%	29.2
other social rented	%	5.8
private rented	%	7.7
living rent free	%	0.8
Houses in fuel poverty	%	24.28

The Scotland Heat Map dataset for Cowdenbeath and Lochgelly contains 7,805 properties. There are approximately 6,800 residential properties in the area. These are distributed as defined in Table 7.

Table 7 : Property usage by type based on information from the Scotland Heat Map

Indicator	Units	Value
Residential		
Detached	%	9.61
Semi - detached	%	45.22
Terraced house (including end-terrace)	%	18.54
Flat or maisonette or apartment	%	26.63

Table 8 : Energy usage by fuel type based on information provided by Fife Council

Indicator	Units	Value
Gas central heating	%	74.2
Oil	%	5.7

Electric	%	13.4
Other	%	6.7

The data provided at the town selection stage for Cowdenbeath was used to develop, through a model, the cost of introducing various heat supply systems for towns in the UK. Cowdenbeath is located within west Fife, Scotland (Figure 9). Cowdenbeath is contiguous with Lumphinnans and Lochgelly which are also included within the study area.

Figure 9 : Location map of Cowdenbeath

4.2 Data Collection

4.2.1 Fife Council Data

In order to generate an accurate energy feasibility model it was essential to gather as much building data as possible for the area of study. The data provided by Fife Council is listed below:

- Scotland Heat Map (including Addressbase data)
- Local Area Plan - adopted Mid Fife Plan (2012) and emerging Fife Local Development Plan (2014)
- Housing Condition Survey for the Area
- Future development trajectories for energy efficiency improvements to Council housing stock
- Building Condition Survey - public buildings energy audits and housing condition survey
- Housing allocation trajectory - housing land audit
- Billing data for municipal buildings (annual and hourly data provided from Stark[12])
- Planned energy efficiency measures for public buildings

[12] Stark is a database of energy metering data that is used by Fife Council for their building estate.

- Typical scope of works for energy efficiency improvements to Council housing stock including description of 2020 target for Energy Efficiency Standard for Social Housing (EESSH)
- Fuel poverty % by DataZone
- Local authority housing data:
  - Property type
  - Heating (includes boiler model, installation date, renewal year)
  - Insulation (energy efficiency measures, installation date, renewal year)
  - Windows & doors (types of glazing installed)

The data received from Fife Council provided clarity on property condition to include in the subsequent analysis.

The heat map primary datasets required some cleaning including relating multiple properties within single buildings through association to the property unique property reference number (UPRN) with Scotland heat map[13] data (Scottish Government, 2016). In addition for Cowdenbeath the data provided by Fife Council on housing stock was merged with Scotland heat map data through a manual process and involved using various excel lookup and database queries.

4.2.2 Site Visits

A series of site visits were conducted to survey the area of study. The purpose of these visits was to:

- Survey building types and ages in the area for greater understanding of engineering challenges associated with alternative heat solutions within the town. Figure 10 shows a typical 4-in-a-block property which is typical of the area;
- Walk the proposed heat network to identify physical barriers and risks to network development;
- Survey any obstacles for heat network i.e. bridges, roads, river crossings and propose alternative routes;
- Ensure zoning of town is in accordance with zoning criteria.

Figure 10: Typical 4 in a block property in Cowdenbeath

4.2.3 Gas Distribution Network Operator

In order to model the changes required to the gas network, details of the existing gas network are required. This is based on gas network drawings and shapefiles[14] that provide the layout of existing gas distribution networks including pipe diameters and materials in the area. This study and the model do not consider any changes to the transmission network.

[13] The Scotland heat map draws together a wide range of data into GIS databases with heat demand mapped to individual properties. This is a partnership project with data contributions from government, public and private sector bodies. All the data in the heat map is held by the Local Authority and combines data from many public organisations including over 70 public bodies that have provided real energy use data.

[14] Shapefiles are commonly used in GIS to store non-topological geometry and attribute information for the spatial features in a data set. The data is associated to the geometry (point, line, and area) for a feature which is stored as a shape comprising a set of vector coordinates. Each attribute record has a one-to-one relationship with the associated shape record.

Scotia Gas Networks (SGN) provided shapefiles in ArcGIS format detailing the existing gas pipe distribution network in the area. This also included a detailed gas pipe network specification. The network supplied by SGN consists of medium and low pressure mains. The gas mains in the UK distribution network fall into the following pressure regimes;

- Intermediate pressure mains which operate between 2 and 7 bar.
- Medium pressure mains operate between 75 mbar and 2 bar.
- Low pressure mains operate at approximately 30 mbar and up to pressures of 75 mbar.

A Medium pressure network supplies natural gas to eight pressure reduction stations across Cowdenbeath & Lochgelly. The pressure reduction stations supply natural gas to Cowdenbeath & Lochgelly via the low pressure gas mains. SGN were additionally able to provide information on various regulated costs for works to the network including connection and disconnection charges and costs of decommissioning.

70% of properties within Cowdenbeath are understood to be supplied with natural gas and use it for space heating (SH). The remainder are supplied by oil, electric or "other" defined in Figure 12. There is no data that defines the individual heating and hot water (DHW) systems for every property. Fife Council were able to provide detailed boiler information for the Council owned residential and community, recreational and educational properties. All Council properties use gas boilers for space heating and hot water. The simplifying assumption in the study is that all properties are currently supplied with natural gas.

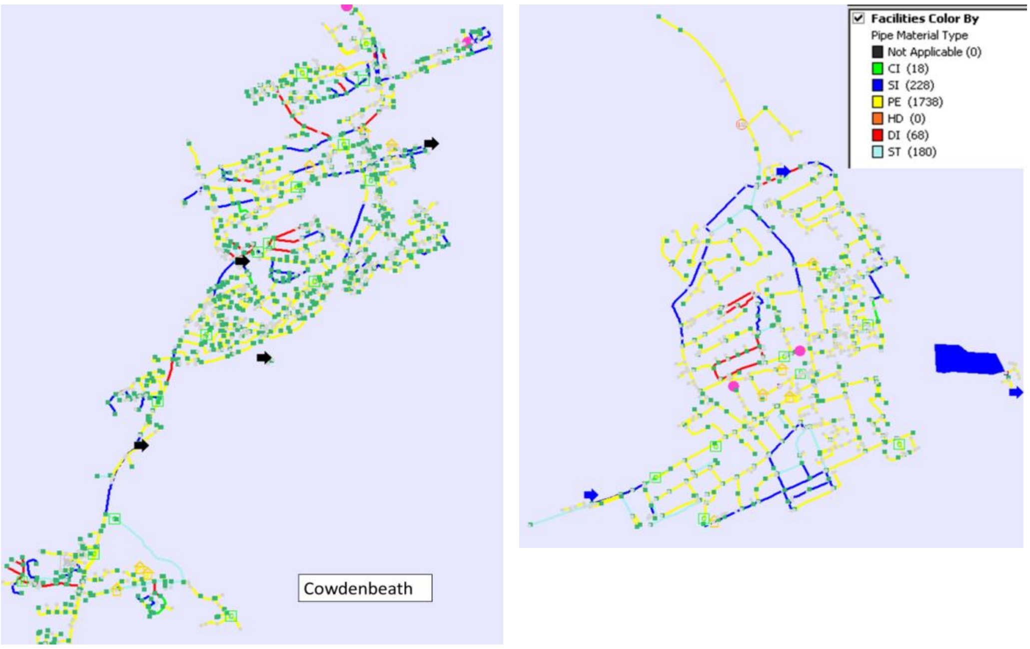


Figure 11 : Illustration of gas networks GIS information provided by SGN indicating pipe materials

The primary fuel used for heating in Cowdenbeath is broadly in line with the UK average published in the "Energy Consumption in the UK Report (Department of Energy & Climate Change, 2014) (Figure 12). A slightly lower proportion of the population use oil, electric heating, which is compensated by a higher than average proportion using gas central heating and other forms (such as solid fuel).

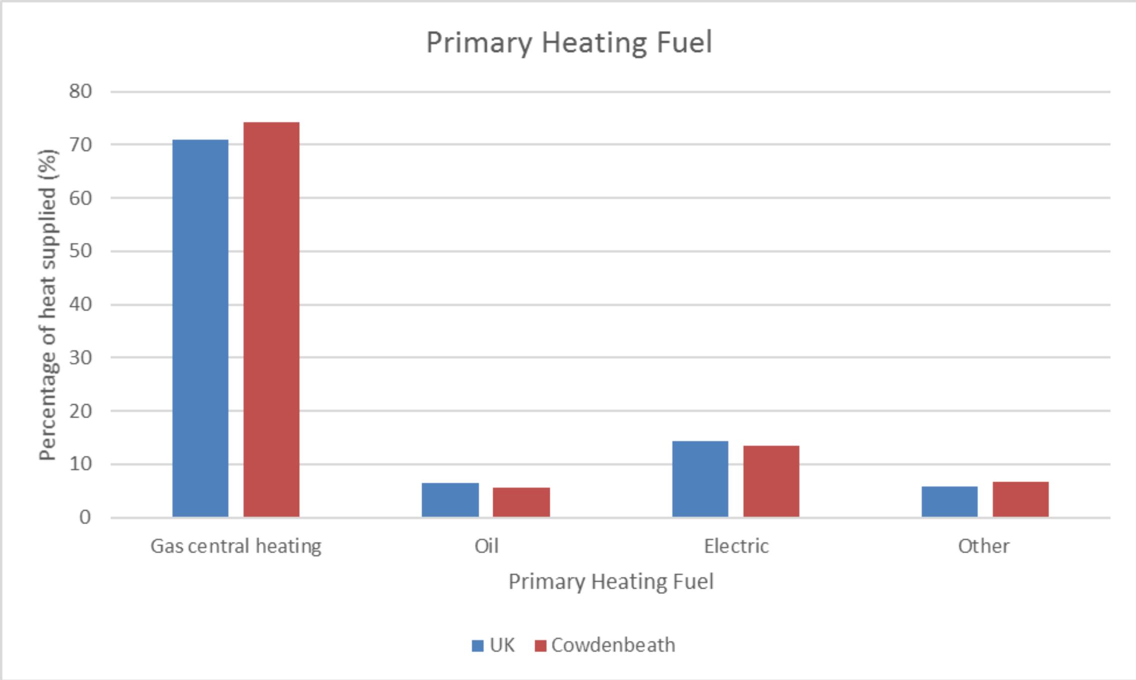


Figure 12 : Illustration of the primary heating fuel compared to UK average

4.2.4 Heat Demand Data from Heat Mapping

The National Heat Map and Scotland Heat Map are used to extract heat demand as appropriate to the area of study. These datasets require permission to use the data and the National Heat Map (NHM) can be obtained from the Centre for Sustainable Energy (CSE). The Scotland Heat Map required permission from the Local Authority, in this case Fife Council, to release the data under their data sharing agreement.

The Scotland Heat Map was built using the One Scotland Gazeteer addressbase unique property reference number (UPRN) as the identifier for all property heat demands.

The SHM dataset for Cowdenbeath and Lochgelly contains 7,805 UPRNs with each of these records having a heat demand associated. The data in the SHM was used in the model and improved with actual billing data where information is available for the properties listed below.

4.2.5 Public Billing Data

Actual energy billing data was used to assign heat demands to properties where possible. This information is usually only available for public buildings in the form of gas meter readings. Billing data was obtained from Fife Council for the following buildings:

- Cowdenbeath Leisure Centre
- Lochgelly Library
- Lochgelly Town Hall
- Broad Street Centre
- Brunton House
- Hill Of Beath Primary School & Nursery
- Lumphinnans Primary School & Nursery
- Cowdenbeath Primary School & Nursery
- Foulford Primary School & Nursery
- St Brides Primary School
- St Patricks Primary School

These gas readings are used to assign an annual heat demand and a profile.

4.2.6 Heat Demand Map

A selection of graphics showing heat demand can be produced to visualise the demand within the town and to select the zone of study. Various layers are used to indicate the characteristics of the town. For example: heat demand density (kWh/m²) and the density of households in fuel poverty. See Figure 13 for heat demand density map of Cowdenbeath & Lochgelly.

Figure 13 : Heat demand density for Cowdenbeath (units are kWh/m²/year)

4.3 Town Demographic

Fife Council is the local authority and they provided access to the Scotland heat map for Fife as well as stock condition and energy demand data, where available, for their housing and council properties.

The study boundary was chosen around Cowdenbeath, Lumphinnans and Lochgelly due to their geographical proximity and the presence of a mix of zones including residential, industrial and commercial and town centre areas. The population of the town in 2013 was 13,677, based on census data for the data zones that define the study area (Scottish Neighbourhood Statistics, n.d.). Relevant statistics are presented in Table 9. The age of the town’s population is representative of the UK with a slightly lower number of working age and a higher percentage of retired residents.

The number of economically active people in the town is typical of the UK average.

Table 9 : Demographic data comparing Cowdenbeath to the UK average and based on information presented by the Office for National Statistics for 2014 and Scottish National Statistics.

Indicator			UK average	Cowdenbeath
Age of pop				
	aged under 18	%	18.8	17.77
	between the age of 18-65	%	64.9	60.26
	aged over 65	%	16.3	21.97
Employment Activity				
	economically active	%	69.8	66.4
	economically inactive	%	30.2	35.7
Property Tenure				
	own a property	%	64.0	58.0
	rent property from council	%	9.7	16.8
	other social rented	%	8.6	14.9
	private rented	%	16.4	9.5
	living rent free	%	1.3	0.8

The residential property tenure mix in Cowdenbeath is broadly similar to that of the UK average, however, there are a higher proportion of social rented properties which results in fewer people owning a property and also less privately rented property. Fife council provided data regarding housing stock which indicated that Cowdenbeath has a high proportion of residential properties compared to industrial which is just 1.7%. Many of the properties are in excess of 30 years old.

Fife council provided information regarding property characteristics within the town. House types include detached, semi-detached, 4-in-a-block and apartments. The housing types within the town were representative of the rest of the UK with the proportion of flats being close to the UK average.

4.3.1 Zoning of Town

In order to compare the performance of the various technology options with respect to the characteristics of individual zones the area of study was divided into smaller zones. The majority of the zones in Cowdenbeath and Lochgelly have a large proportion of residential properties. There are also two large secondary schools in the area which would have their heat supply converted. Figure 14 illustrates the layout of zones and defines the study area.

Figure 15 provides a summary of the zones with a breakdown of their heat demand.

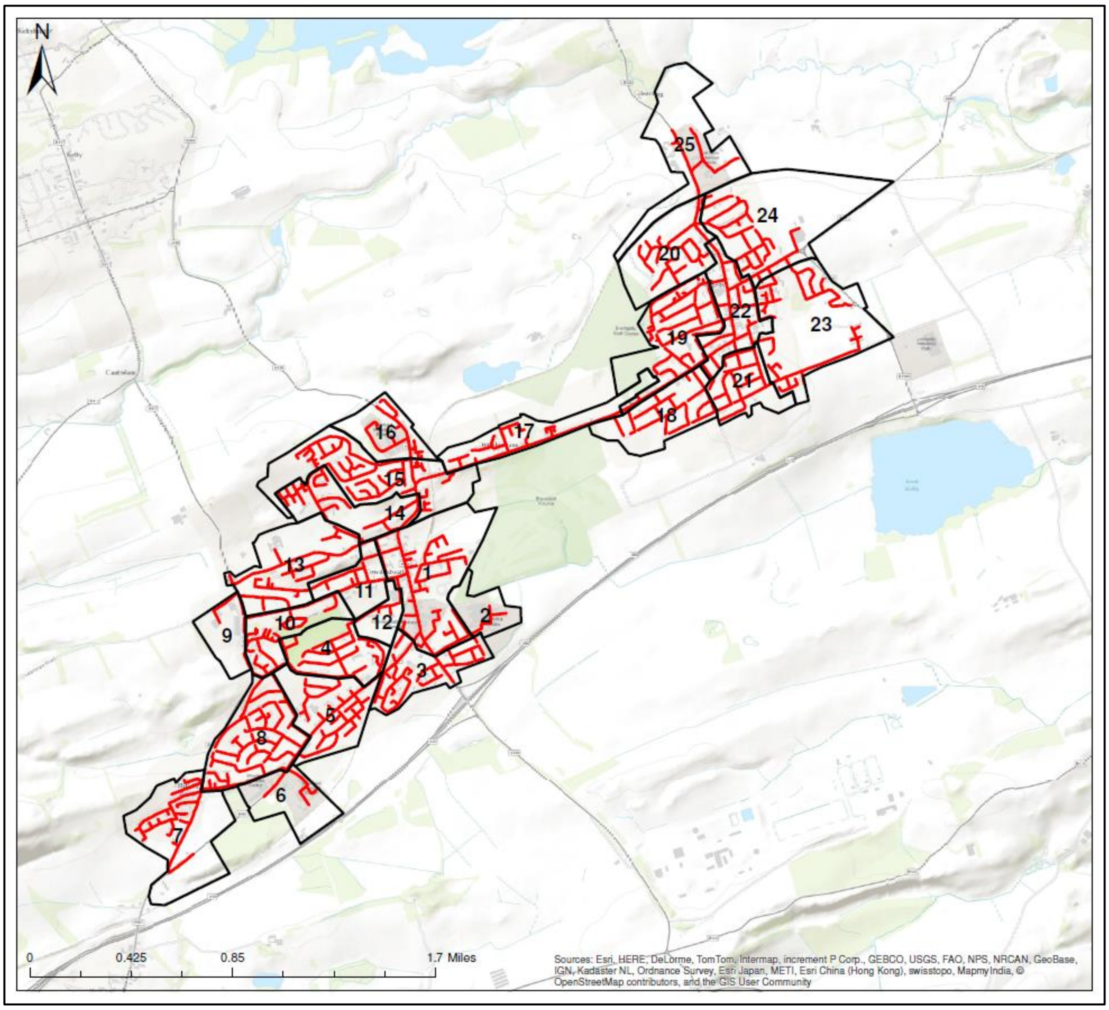


Figure 14 : Zoning of area and proposed network

Zone	Description Property Type	Heat Density (User Inputs)	Total Demand for Centralised Options (kWh)	Land Area (m^2) (User Inputs)	Heat demand (kWh/m^2)
1	Cowdenbeath High Street - Commercial/Residential & Large Morrisons Supermarket	Medium	13,733,991	460695.2	29.8
2	Thistle Stree Industrial Estate - Light Industry	Medium	2,932,844	112892.1	26.0
3	Bridge Stree Residential - Council Semi-Detached, 2-up 2-down, & Cowdenbeath Primary School	High	8,857,064	223284.2	39.7
4	Residential mixture - older/newer bungalows & St. Brides RC Primary School	Medium	6,588,325	219139.1	30.1
5	Broad Street Residential - local authority semi detached - 2 up, 2 down	Medium	9,774,176	260249.4	37.6
6	Woodend Industrial Estate - Medium Industrial	Very Low	3,069,400	188718.0	16.3
7	Hill of Beath - Residential Terraced, Light Industrial, & Hill of Beath Primary School	Very Low	6,388,707	392698.5	16.3
8	Residential - Terraced and Council Semi-Detached	High	12,893,249	329121.7	39.2
9	Gateside Industrial Estate - Food manufacturer & Light Industry	Low	2,368,513	126636.0	18.7
10	Stenhouse Road Residential - Mix of old & new semi-detatched properties and bungalows with green space	Medium	4,790,824	176320.9	27.2
11	Residential - Council owned semi-detached & local Police Station	Medium	4,300,928	136899.2	31.4
12	Cowdenbeath Football Statium and Leisure Centre	Very High	4,681,205	76222.3	61.4
13	Beath High School & Residential - Mix of semi-detached and terraced	Medium	9,857,704	355371.7	27.7
14	Foulford Residential - Mix of terraced and detached housing & Foulford Primary School	Medium	5,259,737	225791.3	23.3
15	New Residential - Modern detached housing and new developments	Medium	10,226,956	420748.8	24.3
16	Glenfield Industrial Estate - Light Industrial	Low	3,281,196	165484.5	19.8
17	Residential & light commercial - Semi detached housing & Lumphinnans Primary Community School	Medium	5,103,163	213731.9	23.9
18	Residential & light commercial - Semi detached housing & small number of flats	Medium	8,261,322	244103.1	33.8
19	Residential - Council semi detached housing, small number of flats & Lochgelly West and North Primary Schools	Medium	10,678,130	330230.2	32.3
20	Residential Mixed - Modern detached housing & new developments	Low	6,081,702	281703.6	21.6
21	Lochgelly South - Residential Semi detached housing & Lochgelly South Primary School	High	6,825,062	172254.3	39.6
22	Lochgelly High Street - Commercial & small number of flats about high street shops	High	13,027,680	211611.3	61.6
23	Lochgelly East - Modern detached residential and some light industrial	Low	9,570,513	500535.2	19.1
24	Lochgelly North - Residential mixture of semi-detached & bungalow	Low	9,301,703	557670.1	16.7
25	Cartmore Industrial Estate - Light Industrial & Lochgelly High School	Low	6,282,041	368489.0	17.0
Total			184,136,136	6750602	28

Figure 15 : Zone description and associated heat demand data (red indicates zones of greatest heat demand/density)

All heat demand data was reviewed by Ramboll analysts before inputting into the heat map. This included removing a number of buildings that should not have a heat demand allocated, such as substations and bus stops. In addition some heat demands in the map are under or over-estimated and these have been corrected. Notably the heat demands for Fife Council's properties were obtained from the Council's own energy billing data and corrected in the heat map.

Fife Council provided their stock condition survey in Council residential properties, including existing energy efficiency measures, such as loft and cavity wall insulation. This information was then used to provide an estimate of the pre-existing energy savings in terms of % reduction in heat demand as shown in Figure 16.

Zone	Description Property Type	Proportion of Local Authority and RSL owned Properties (User Inputs)	Proportion of residential properties	Pre-Existing Energy Saving (%)
1	Cowdenbeath High Street - Commercial/Residential & Large Morrisons Supermarket	33.1%	71.6%	1.6%
2	Thistle Stree Industrial Estate - Light Industry	0.0%	0.0%	0.0%
3	Bridge Stree Residential - Council Semi-Detached, 2-up 2-down, & Cowdenbeath Primary School	16.0%	95.9%	1.2%
4	Residential mixture - older/newer bungalows & St. Brides RC Primary School	37.1%	97.5%	3.9%
5	Broad Street Residential - local authority semi detached - 2 up, 2 down	43.5%	98.2%	6.8%
6	Woodend Industrial Estate - Medium Industrial	0.0%	8.7%	0.0%
7	Hill of Beath - Residential Terraced, Light Industrial, & Hill of Beath Primary School	25.5%	95.3%	3.5%
8	Residential - Terraced and Council Semi-Detached	48.5%	99.6%	7.9%
9	Gateside Industrial Estate - Food manufacturer & Light Industry	0.0%	0.0%	0.0%
10	Stenhouse Road Residential - Mix of old & new semi-detatched properties and bungalows with green space	37.5%	98.9%	4.5%
11	Residential - Council owned semi-detached & local Police Station	26.7%	94.9%	2.7%
12	Cowdenbeath Football Statium and Leisure Centre	0.0%	0.0%	0.0%
13	Beath High School & Residential - Mix of semi-detached and terraced	26.4%	98.4%	4.7%
14	Foulford Residential - Mix of terraced and detached housing & Foulford Primary School	1.8%	98.6%	2.2%
15	New Residential - Modern detached housing and new developments	11.1%	97.5%	0.4%
16	Glenfield Industrial Estate - Light Industrial	26.0%	83.2%	2.4%
17	Residential & light commercial - Semi detached housing & Lumphinnans Primary Community School	57.1%	97.6%	2.8%
18	Residential & light commercial - Semi detached housing & small number of flats	47.5%	99.0%	5.6%
19	Residential - Council semi detached housing, small number of flats & Lochgelly West and North Primary Schools	36.3%	95.8%	3.1%
20	Residential Mixed - Modern detached housing & new developments	5.3%	97.3%	0.4%
21	Lochgelly South - Residential Semi detached housing & Lochgelly South Primary School	30.3%	98.2%	4.4%
22	Lochgelly High Street - Commercial & small number of flats about high street shops	29.0%	81.3%	1.0%
23	Lochgelly East - Modern detached residential and some light industrial	21.9%	95.3%	4.1%
24	Lochgelly North - Residential mixture of semi-detached & bungalow	38.7%	96.8%	5.2%
25	Cartmore Industrial Estate - Light Industrial & Lochgelly High School	0.0%	26.5%	0.0%
Total		31%	94%	3.01%

Figure 16 : Characteristics of property ownership, types and condition within zones

4.4 Modelling Description and Assumptions

The model is structured to provide a simple user interface with a single page to manage all data input (Figure 17). The model is broken down into a series of stages to describe the relevant data, the technical scenario to be modelled and reporting.

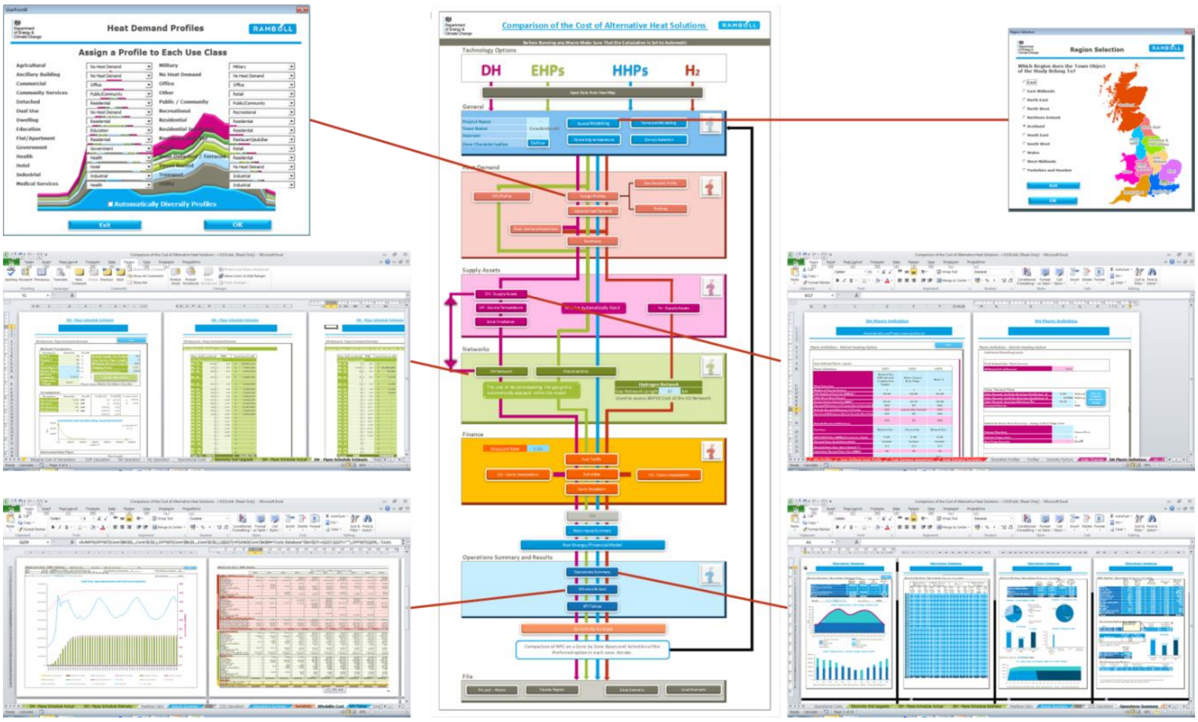
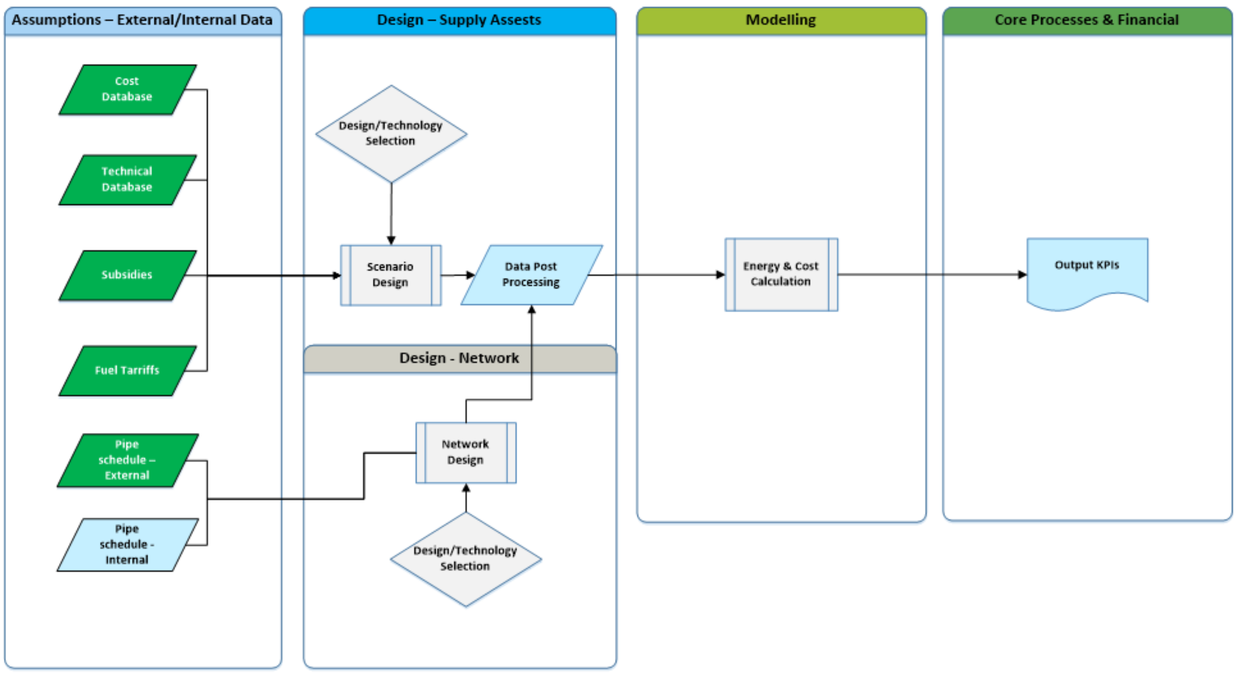


Figure 17 : Model user interface

4.4.1 Model Map

A model map has been completed which sets out the structure and provides a guide to follow the user-interface in the model. Level 0 of the model map is shown earlier in Figure 4 (reproduced below).



4.4.2 Modelling Methodology

The model provides a detailed bottom-up estimate of the capital costs to convert a UK town from natural gas heating and cooking to alternative low-carbon technologies. This is based on a series of user-defined scenarios and data from publically available data sources to characterise the selected town.

The model presents the outputs and results of analysis in terms of the data defining the technical operation of the system, the whole-life cost of the solution and a series of KPIs that define the economic and carbon performance of the proposal.

The model can be run for other towns and cities in the UK. There are limitations in relation to the modelling approach for other towns in the UK since there will be local variation in particular in relation to the capacity of the electricity, gas network and district heating network. These should be validated within a separate assessment of the infrastructure capacity. The analysis undertaken in this Study is further described in Appendix C, Section 5.2.2.4 and Section 5.2.5 respectively. The results for Cowdenbeath are presented in Section 5 and Appendix C.1.2 and B.2.2. The main indicators of performance that are presented in the results from the model are:

- Technical outputs including annual running hours, heat and electrical production from each plant;
- Breakdown of the lifecycle cost within a cost plan presenting annual CAPEX, OPEX (including fuel cost) and REPEX;
- Discounted net present cost (NPC) of each solution;
- Comparison of NPC against area and linear heat density; and
- Lifecycle carbon emissions and cost of carbon abatement.
- The model can be used as an illustrative comparison of the four technology options with a number of different assumptions applied.

The model is built to allow flexibility to change the technical assumptions regarding the size and type of energy generation. The timescales for deployment and for lifecycle duration can be adjusted. Cost data in the model is derived from a number of sources, however, particularly for new technologies; there remains some uncertainty around the initial cost of equipment and the trajectory for the cost to reduce. The model includes functionality for the user to define cost reduction curves. It also includes sensitivity analysis to describe the effect of varying key parameters.

4.4.3 Energy Demand

4.4.3.1 Demand Profiles

Heat demand profiles are modelled as a 12 x 24 matrix to represent the variation in hourly heat demand over the year. The model has twelve built-in daily profiles, plus one additional profile which can be specified by the user. The profiles represent the most common building types: Office, Education, Residential, Industrial, Recreational, Government, Retail, Restaurants/Pubs/Bars, Hotel, Military, Health, Public/Community. The profiles have been built up based on experience from data for typical building demands in the UK and factor the annual demand to give a simplified hourly demand profile

The individual property annual heat demand is obtained from the National Heat Map or the Scotland Heat Map depending on the selected region. Each property is automatically assigned a property use class which is associated with a typical heat demand profile.

Each profile is the combination of two sub-profiles: one for the DHW and one for the SH demands, both normalised to the daily peak demand. Both profiles are the result of a weighted average of weekdays and weekend daily profiles. The two profiles are then combined into one normalised profile through a weighted average, which uses the proportion of the annual demand allocated to DHW as a weighing factor to reflect the different proportions of heat used for space heating and hot water based on the property usage.

The normalised profiles are then diversified to reflect the fact that not all peaks will occur simultaneously. This is done by smoothing them until the peak reaches the diversified[15] peak. Diversified profiles are then used in the DH and hydrogen options, to account for variability across the networks.

The analysis results are presented in this report for standard operating temperatures for the technology options considered. One additional analysis is presented for a scenario whereby energy efficiency measures are implemented allowing each technology to operate at a reduced / lower temperature. In this case heating profiles for certain use classes (i.e. Residential, Health and Hotel) are smoothed to reflect the profile of a continuously heated building. This is explained in point 1 of the next sub-section.

4.4.3.2 Heat Pumps Profiles

Profiles for individual consumers under the EHPs and the HHPs options are treated differently for two reasons:

1. It is assumed that it would be more cost effective to run the heating system continuously under both the EHPs and the HHPs options for the following use classes: residential, hotel, health. For this reason the heating profile would be smoother, as the heat losses would be continuously compensated. The same has been assumed for the DH and H2 option under a low temperature scenario. The assumed heating profile for a continuously heated building is shown in Figure 18.
2. In the EHPs option heating of the hot water storage in residential units is likely to happen in the early hours of the morning, prior to the morning peak, and taking advantage of lower electricity tariffs rates. The model allows for diversification of the hot water storage profile, which can be achieved through, for instance, demand side management. However, such a scenario has not been modelled. As a consequence, it has been assumed that storage in all residential units would happen in the early hours of the morning.

The DHW and the SH profiles, for both the EHPs and the HHPs options, are then combined into one normalised profile through a weighted average, which uses the proportion of the annual demand allocated to DHW as weighing factor.

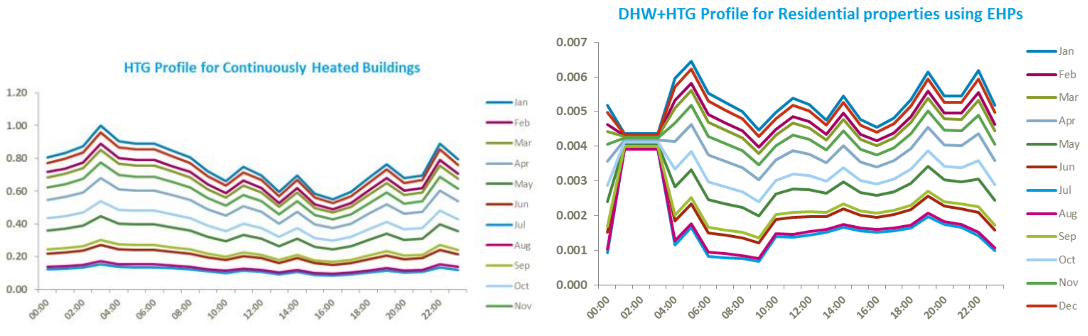


Figure 18 : Typical normalised annual heat demand profiles

The profiles are developed based on the expected shape of domestic heating and hot water demands from Ramboll experience. The overlay of these data sources results in an uneven heat demand through the day. The EHP profile shows a typical period of cylinder pre-heating in the morning between 01:00 and 03:00.

[15] The diversity factor is a measure of the probability that a heat demand will occur concurrently with another customer at the same time. In district heating networks it is the ratio of the probable peak demand to the maximum theoretical demand of the complete system.

4.4.3.3 Distribution Temperatures

The model is used to analyse both high and low distribution temperatures in buildings. This allows a comparison considering the effect of investment in energy efficiency measures[16] (EEM) in accordance with the energy hierarchy which is central to the UK Government's policies for decarbonisation of the energy system. These are combined with increased emitter sizes.

Heat pumps and low temperature district heating perform most efficiently at lower temperature. They are assumed to require changes to the control and sizing of secondary or tertiary heating systems[17] to be capable of achieving thermal comfort when operating at low system temperature. The optimum flow and return temperatures of these technologies are assumed to be lower than the typical standards of building design for existing properties. If lower heat supply temperatures are used then the property heating system will need to be capable of delivering the required thermal comfort and achieving the return temperatures in order for the system to operate efficiently. In order to achieve the required thermal comfort a combination of fabric energy efficiency and radiator upgrades are assumed to be required. This requires a combination of:

- Improved fabric energy efficiency to reduce the total heat demand and to allow the current emitters (radiators or underfloor heating) to reduce their average temperatures;
- Increased emitter sizes to increase the heat transfer based on lower system temperatures.

In order to take account of these requirements, the model calculates the requirement for a combination of future energy efficiency improvements to the existing building stock and changes to the emitter sizes and includes these costs in cost calculations.

The optimisation of individual properties' energy systems require appropriate measures. For example solid wall and non-standard constructions may not be capable of installing cavity wall insulation. Energy efficiency savings may not be appropriate or achievable in historic buildings with listed or conservation status. The model makes a simplifying assumption that energy efficiency savings can be achieved across the whole town.

The effect of EEMs can also be to reduce the building heating system distribution temperature which can have a positive effect on the efficiency of heat generation and distribution. The temperature assumptions for low and high temperature are explained below.

Table 10: Temperature assumptions for low and high temperature

Assumption Title	Supply Temp	Units	Methodology behind assumption	Evidence
District Heating network operating at high temperature	90/65	ºC	High temperature limit is suitable for existing building assuming they can be modified to operate at 80/60°C. A high flow temperature has been selected to maximise the DeltaT to minimise the capital cost of the network.	Heat Networks Code of Practice for the UK Raising standards for heat supply CP1 2015

[16] Loft insulation, cavity wall insulation, draught proofing are considered in this study to achieve the energy efficiency reductions.

[17] The term secondary and tertiary heating systems refers to the wet heating system at the customer side (ie. the heating system comprising pipes and radiators delivering heat to the property.

District Heating network operating at low temperature	75/45	ºC	Low temperature network is based on internal flow and return temperature of 70/40ºC as recommended by CP1 with an approach temp of 5ºC.
EHPs and HHPs option operating at high temperature	65	ºC	The COP and SPF are assessed according to this operating temperature as well as the average hourly external air temperatures.
EHPs and HHPs option operating at low temperature	45	ºC	The COP and SPF are assessed according to this operating temperature as well as the average hourly external air temperatures. The temperature of the water within the customer DHW storage system shall be raised above 60°C for a period of one hour per day (non-domestic) and one hour per week (domestic) to control for legionella.

The cost of fabric energy efficiency measures is based on the installation of loft and cavity wall insulation combined with an upgrade of the heating system. The model applies a simplifying assumption that all properties can install both loft and cavity wall insulation and it is noted that properties with solid walls will have a lower cost and lower energy reduction. Other measures, such as draught proofing, underfloor insulation and heating controls are also alternative measures. Costs are derived from:

- Information for the Supply Chain on Green Deal Measures (DECC, 2015); and
- Energy Saving Trust home energy check website (EST, 2016)

Costs of heating system upgrades are derived from Spon's Mechanical and Electrical Services Price Book 2015 (AECOM, 2015) based on materials and labour cost for estimated replacement of a defined number of radiators per property depending on size.

The installation of EEMs will have a direct effect on reducing demand. The model assumes that for EHP and HHP operating at high temperature, or hydrogen and district heating operating at low temperature, at least 46% reduction in heat demand from current levels of insulation would have to be achieved within individual properties through FEE.

Since the cost of achieving this is considered to be unrealistically high the model assumes that 23%[18] of that reduction is assumed to come from improved fabric energy efficiency. Heating systems upgrade[19] will deliver the residual requirement to achieve thermal comfort.

---

[18] 23% is determined to be a cost effective and reasonable level of energy saving from implementing loft and cavity wall insulation and based on information included in Information for the Supply Chain on Green Deal Measures (DECC, 2015).

[19] Heating system upgrades to deliver thermal comfort under reduced supply temperature comprise replacement with larger emitters.

In the low temperature scenario for EHP and HHP, the operating temperature is set to 45°C. To compensate for thermal comfort it is assumed that at least 60% reduction in heat demand would have to be achieved within individual properties through FEE and upgrading of their heating system as above. Since the cost of achieving 60% reduction is considered to be unrealistically high the model assumes that 23% of that reduction is assumed to come from improved fabric energy efficiency. Heating systems upgrade will deliver the residual requirement to achieve thermal comfort.

Fife Council provided data on their housing stock condition including details of energy efficiency measures that have been undertaken already. The effect of these fabric energy efficiency works, which are referred to as pre-existing energy savings, are a reduction in the baseline heat demand. The estimate of the pre-existing energy savings is calculated as a weighted average for all properties within the zone. It is based on the housing condition data provided by Fife Council including energy saving contributions from cavity wall insulation, loft insulation and window replacements.

There is uncertainty around the trajectory for the upgrade of fabric energy efficiency installation and resultant demand within existing and future housing stock.

4.4.3.4 Peak Demand Assessment

The peak demand assessment is carried out within the model for each consumer and for the DHW and SH demands.

The SH peak load is assessed through the SH profiles. Since these profiles are averaged, the assessed peak is then scaled up to reflect design temperatures. This is done through the ratio between ΔT_{Design} and ΔT_{avg} which are the difference between the heating set point and the design external air temperature, and between the heating set point and the average external air temperature respectively. Finally the SH peak load is reconverted from an average weekly peak into a weekday peak load.

The DHW peak assessment is done assuming the following:

1. If a building has more than twenty consumers, or if a consumer's annual thermal demand (inclusive of heating and hot water demands) is greater than 20 MWh, then it is assumed that a hot water storage tank is in place. The DHW peak demand is assessed using the built-in DHW profiles.
2. Where point 1 does not apply, the model assumes the DHW peak load in relation to the annual demand (inclusive of heating and hot water demands) as per Table 11.

Design Parameters to Size Boilers in Residential Buildings (<20 consumers)		
Total Individual DHW + SH Demand (kWh)	Instantaneous Demand (kW)	Comments
<12000	35	All boilers sized same below 12000 kWh
>12000	NA	Condensing boilers with cylinder- Size based on individual property heat demand profiles

Table 11 : Design parameters for sizing boilers in residential buildings

For the EHPs and the HHPs option the annual thermal demand is reduced to account for installation of FEEs and, in the low temperature scenario, upgrading of the heating system.

For the district heating and hydrogen option the annual thermal demand is reduced under the low temperature option to reflect installation of fabric energy efficiency measures. For these options the peak load is also diversified. This is done using the Danish Standards (DS439) for residential units which is a common approach used in the absence of UK standards. For non-domestic consumers it has been assumed a minimum ratio between the diversified DHW peak load and the undiversified DHW peak load of 60% and a minimum ratio between the diversified SH peak load and the undiversified SH peak load of 80%.

The diversified peak load for the district heating option is then increased to account for heat losses. This calculation is described in the district heating network sub-section (Section 5.2.5). The diversified peak load for the hydrogen option is also increased to account for gas leakage in the network and for the boiler efficiency of consumers. The annual losses are estimated to be 1.25% of delivered energy and the boiler losses are estimated to be 15% (based on a gross efficiency of 85%).

4.4.3.5 Diversity of Demand

The assessment of the energy demand from multiple buildings affects the generation and district heating network capacity. This requires an estimate of diversity based on the likelihood of variable demands calling for heat simultaneously.

The use of annual load duration curves is useful in determining the appropriate mix of heat (or power) generators. An annual load duration curve is a cumulative frequency distribution of load, so that any point on the curve of fractional heating load represents the number of hours in the year for which the heating demand will be greater than the value indicated.

In order for the generation plant to be a reasonable match to the load profile for most of the year without incurring a disproportionate initial investment, this study considers that the energy centre for heat generation is sized based on a 40% of the peak load basis. (This figure may vary for some technologies like the off-take plants or the solar where the presence of seasonal storage allows this energy generation to be sized slightly higher i.e. 50%). Hydrogen production will be compensated by storage and in combination are sized to the peak demand.

Figure 19 and Figure 20 below were extracted from the model and shows clearly that sizing the low and zero carbon (LZC) technology peak on a 40% of the non-diversified peak implies that more than 80% of the energy required by the district heating network could be provided by the LZC technology. Similarly but slightly more conservative on Figure 20 it can be seen that sizing the LZC technology peak on a 40% of the diversified peak implies that more than 65% of the energy required by the network could be provided by the LZC Technology.

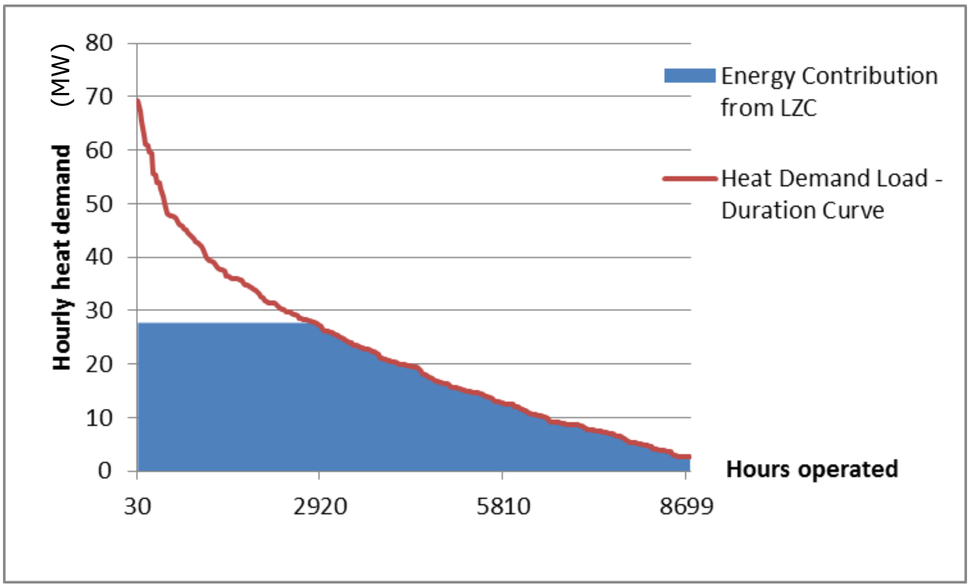


Figure 19 : LZC Energy Contribution under non-diversified Duration Curve

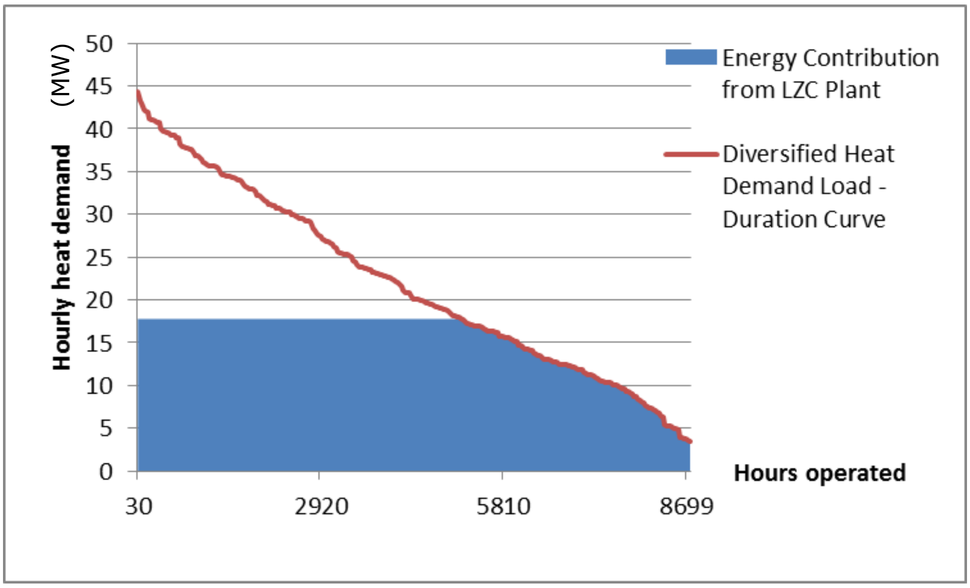


Figure 20 : LZC Energy Contribution under diversified Duration Curve

4.4.4 Heat Demand Data from Heat Mapping

In order to define the electricity distribution network upgrades, details of the existing electricity network are required. This was based on electricity network drawings, and schedules of the electricity network infrastructure.

Continuous dialogue with the relevant licenced DNO, in the case of the current study Scottish Power Distribution (SPD), was limited and therefore only data that was available in the public domain was utilised. This was found to be sufficient to determine the reinforcement requirements for Cowdenbeath/Lochgelly and would generally be suitable elsewhere. Specific circumstances will dictate that the modelling assumptions are not applicable in all cases.

The following data was used:

- Demand data obtained from the SPD's Long Term Development Statement 2014/15 – 2018/19 (LTDS) using the declared peak demand forecast for each substation supplying the town
- Town network topology data covering all voltages from LV up to and including 132 kV.
- Standard SPD equipment schedule for all voltage levels from LV up to and including 132 kV. This will include specification of overhead lines, cable, ring main units, transformers, and substations.

5. ANALYSIS METHODOLOGY

The report presents the results of the analysis for a series of scenarios and are compared against a business as usual scenario. The BAU is based on the assumption that all properties remain connected to the gas network and continue to operate using gas boilers. The model includes the cost of periodic lifecycle replacement (15 years) of individual boilers.

The scenarios are further described in the following sections and the scenarios that were considered are listed below:

Scenario	Brief description	H_2	EHP	HHP	DH
Main	Deployment of respective technology solutions in Cowdenbeath. These would occur in the same timescale as large scale national deployment of technology and the inherent economy of scale that can be achieved through deploying the technology options.	✓	✓	✓	✓
Low Temp	Fabric energy efficiency measures and upgraded customer heating systems would allow lower temperatures in customer heating systems. This would reduce DH network heat losses. A wider selection of low carbon heat generation technology are compatible with low temperatures.	✓	✓	✓	✓
Pilot	Cowdenbeath is in close proximity to the Mossmorran Ethylene Plant which produces hydrogen as a by-product of its process. A pilot scenario for hydrogen distribution at Cowdenbeath is modelled whereby hydrogen is generated at the Mossmorran ethylene plant and supplied to the network.	✓			

Table 12 : Scenarios modelled and reported

In addition to the alternative scenarios considered a sensitivity analysis was undertaken on the main scenario to test the impact on the economic and carbon performance of the technologies of changes to key economic assumptions.

5.1 Modelled Timescales

The technologies were modelled in all scenarios based on a deployment year starting in 2030. The nature of the hydrogen conversion requires the gas network to be fully switched from natural gas to hydrogen in a finite period, one year is assumed. The other technologies lend themselves for a phased deployment. EHP and HHPs can be switched in at lifecycle replacement of existing boilers with a maximum boiler life of 15 years. The DH solution is modelled to grow in a phased manner as set out in Table 20.

	Policy change (date + description)	Full solution implemented	Model period (NPC reported)
H2	2030 – before 2030 business as usual remains	2030	2030-2070
DH	2030 – before 2030 business as usual remains and from 2030 phased development of DH across the town	2045	2030-2070
EHP	2030 – before 2030 business as usual remains and from 2030 boilers replaced with EHP at end of life	2045	2030-2070
HHP	2030 – before 2030 business as usual remains and from 2030 boilers replaced with HHP at end of life	2045	2030-2070

Table 13 : Timescales of deployment and economic modelling applied in the modelling for each technology option

5.2 Main scenario

The underlying cost assumptions in this scenario are based on a presumption that for each of the technologies considered a national roll-out happens before or concurrently with the deployment in Cowdenbeath. As a result it is assumed that the cost of technologies have fallen in line with projected cost reductions due to the scaling up of the supply chain and market competition. The following sections describe the primary assumptions across technology options.

5.2.1 Primary Fuel Costs

The primary fuel costs are assumed to escalate based on BEIS fossil fuel price projections (DECC, 2015). Hydrogen follows the natural gas price projection as the scenario assumes hydrogen generated using steam methane reformation of natural gas, heat pumps follow the electricity price projection and district heating follows the projection for biomass, electricity and natural gas.

5.2.2 Hydrogen Technology

The analysis is based on a number of assumptions that are built into the model and have been researched as part of the development of the study. It is notable that the information and assumptions for the cost and efficiencies associated with hydrogen generation, carbon capture and storage and customer equipment are contained in a limited number of reports. These technologies are not as fully developed and proven as the other technologies.

The following sections describe how the individual parts of the hydrogen system have been modelled for the specific requirements in Cowdenbeath. The model makes a distinction between elements of the system within the town and those outside the town (Figure 8). In the main scenario the plant is outside the town and the cost is accounted for as a levelised cost of hydrogen delivered as a utility.

The design of the gas system, metering and components that operate on hydrogen would need to comply with the prevailing best practice guidance and regulations at the time of installation. At present hydrogen is not specifically covered in gas standards and regulations for domestic consumers. A recent study for BEIS into Safety Issues Surrounding Hydrogen as an Energy Storage Vector (Kiwa Ltd, 2015) made real measurements on gas risk at an existing property (HyHouse) as a case study. The report demonstrated the potential of hydrogen as a fuel source as a safe replacement for natural gas. This report stated that all flammable gases need appropriate engineering. The project provided evidence that hydrogen does not inherently offer risks over and above other flammable gases, for example Natural Gas, LPG or Town Gas.

5.2.2.1 Hydrogen Generation

Under the main scenario hydrogen is assumed to be generated at national scale by steam methane reformation (SMR). This has CO_2 as a by-product and the scenario further accounts for the cost of carbon capture and storage (CCS).

5.2.2.2 Assumptions for hydrogen technology option

The main scenario considered in this report is based on the assumptions set out in Table 14.

Table 14: Assumptions for hydrogen production from steam methane reformation (with and without carbon capture and storage)

Key Assumption	Value	Units	Explanation
Levelised cost of hydrogen generation from SMR without CCS (wholesale cost)	0.028	£/kWh	The model assumes a levelised cost of hydrogen generation based on information presented in the 2015 annual report[20] of the CO_2 Capture Project (CO_2 Capture Project, 2016).
Levelised cost of hydrogen generation from SMR with Carbon Capture (wholesale cost)	0.033	£/kWh	The model uses the same assumption but also includes the assumed cost of Carbon Capture from Shifted Syngas using MDEA (CO2 Capture Project, 2016).
Cost of CO_2 transmission and sequestration	40	£/tonne of CO_2	Cost of transmission of CO_2 and sequestration in a suitable site (H21 Leeds City Gate, 2016).
Steam Methane Reformer Efficiency	80.0	%	Natural Gas to hydrogen Conversion Efficiency (used in carbon calculation)
Plant replacement costs of SMR technology	2.00	% of plant capex	2% annualised cost of lifecycle replacement and 20% every 5 years + 5 yearly balance of plant replacement
Efficiency of CCS (remaining CO_2 lost to atmosphere)	90	%	Information provided by BEIS

5.2.2.3 Hydrogen Storage

The peak demand across the network is expected to occur during the winter season during the morning when demand for hot water is greatest. This would place significant demand on the gas generator. The main scenario relies on the national gas network having storage through line packing[21] at variable pressure.

5.2.2.4 Gas Network Infrastructure

The current natural gas network supplying Cowdenbeath & Lochgelly is made of a variety of pipe materials: stainless steel, polyethylene (PE), ductile iron, spun iron and cast iron. SGN intend to utilise PE pipework in the future and have begun replacing non-PE pipework across their networks.

The model is based on an assumption that iron pipes in the existing gas distribution network will be replaced before deployment of the solution as part of the on-going Iron Mains Risk Reduction programme. The whole distribution network is assumed to be converted to polyethylene at the point of switching to hydrogen. SGN advised that plastic pipework has been shown to be suitable for distributing hydrogen up to a pressure of 4 bar (Scotia Gas Networks, 27-05-2015).
The delivery pressure requirement for the gas network will depend on the requirements of standard hydrogen heating equipment. It is assumed that existing boiler manufacturers would develop combustion hydrogen boilers that are capable of operation under the current delivery pressures.

The gas distribution network for the selected town requires modelling in an appropriate hydraulic model to verify the capacity for hydrogen distribution in the existing network and to identify any additional investment costs in pipe infrastructure. The study modelled the

[20] http://www.co2captureproject.org/reports/ANNUAL_REPORT_2015.pdf
[21] Line packing is a term that describes the storage of gas within the transmission pipework by varying the pressure

existing hydrogen network and found that it has sufficient capacity to accommodate the existing demand. The peak heat demand was simulated in a gas pipe flow model for natural gas and hydrogen. The energy delivery capacity of the network is reduced by only around 10%, this finding is shared with other studies, the H21 Leeds Citygate project (H21 Leeds City Gate, 2016).

Based on a literature review and assuming an unchanged pipeline and network operating pressure little or no upgrades in terms of pipe dimensions are suggested to be required with the move from natural gas to hydrogen.

The methodology for analysis of the gas network capacity that was undertaken in this study is provided in Appendix B.2.

Table 15: Assumptions for conversion of gas network delivering hydrogen

Key Assumption	Value	Units	Explanation
Relative Density	0.0696		
Absolute Temperature (K)	293	K	
Supercompressibility	1		
Dynamic Viscosity (bar.s)	0.88 x 10-10	Bar.s	
Higher Heating Value ()	12.7	MJ/m³	
H2 Network life	45.0	years	A sinking fund is allocated to cover the cost of H2 network replacement and based on the expected lifetime
Existing Gas Pipe Network Sizes	varies	DN	Existing gas network pipe diameters were provided by SGN
OPEX Cost of hydrogen network	25.00	£/property/yr	OPEX Cost associated with the hydrogen network based on discussion with SGN
REPEX Cost Of hydrogen network	350.00	£/m	REPEX Cost associated with the hydrogen network based on discussion with SGN
Leakage rates of pipes	1	%	The yearly loss of hydrogen by leakage amounts to 0.5 – 1% of the total transported volume in a PE (polyethylene) pipe. A value of 1% has been assumed for the purpose of modelling.

The impact of using hydrogen gas in the existing natural gas network supplying Cowdenbeath & Lochgelly was modelled using the same system operating pressures as the existing gas network but with the gas parameters changed for hydrogen. This modelling was undertaken in order to ascertain at a high level the change in performance compared to the existing natural gas system. The results of the modelling indicated that the capacity within the hydrogen network would be reduced by up to 17% compared to the natural gas network pipeline. The majority of the system is shown to already have some over-capacity and therefore upgrades are assumed to be negligible.
This modelling generally agrees with evidence from the H21 Leeds Citygate project[22] (H21 Leeds City Gate, 2016). Ramboll's pipe specialists have considered the opportunity to increase capacity in the gas network. The low pressure network is expected to be capable of handling an increase in pressure from around 40 mbar to 75 mbar, this in effect picks up a significant percentage of the capacity 'loss' in between methane to hydrogen conversion.

[22] H21 Leeds City Gate partners are: Northern Gas Networks, Kiwa Gastec, Amec Foster Wheeler

The hydrogen network is capable of supplying at least 83% of the energy compared to natural gas. This could be improved by increasing the network operating pressure for the hydrogen gas network. The currently installed network, when converted to PE, could handle an increase in the current network operating pressure up to 75 mbar. The results predict that the existing gas network is capable of handling hydrogen without any additional capacity upgrades to the present network. This leads to the assumption that there is no additional infrastructure cost to converting to hydrogen. There is, however a conversion cost and this has been included in the modelling.

5.2.2.5 Individual Property Interfaces

Customer interfaces to the hydrogen network will be via a gas incomer comprising a meter and shut-off valve arrangement. The model assumes that consumers will utilise hydrogen in a condensing gas boiler unit. Due to the availability of electrical cooking appliances it is assumed that development of bespoke hydrogen units is unlikely and the model assumes that electrical cooking will prevail.

Table 16: Assumptions for customer boilers supplied with hydrogen

Key Assumption	Value	Units	Explanation
Boiler efficiency	85.00	%	Assumption advised by BEIS based on EST's 2009 field trial of condensing gas boilers[23].
H2 Boiler Costs under main scenario	Varies 35kW: £5,200 1MW: £84,000	£	For the main scenario with a national roll out, it has been assumed that the cost of H_2 boilers would reduce significantly and would reach the cost of gas boilers of equivalent size at the first boiler replacement.

The HyHouse study (Kiwa Ltd, 2015) indicates that hydrogen installations in properties might require safety measures. These measures would be relatively simple to implement in the period of boiler replacement. The installation of additional ventilation may be needed to mitigate the evidence seen at HyHouse where hydrogen accumulates in the highest place. The cost of these conversions is not expected to be significant and is built into the cost of hydrogen boilers.

5.2.3 Electric and Hybrid Heat Pumps

5.2.3.1 Electricity and Gas Generation and Distribution

The model for the heat pump scenarios applies a cost of electricity purchased at the boundary of the town.
The assumption, that the electricity generation is external to the model and supplied from the electricity grid, builds the capital cost of generation into the wholesale purchase price of electricity.

The model does therefore not account for electricity transmission upgrade or the surcharge cost of additional generation capacity as a result of the electrification scenarios.

5.2.3.2 Gas Network Infrastructure (Hybrid Heat Pump Option)

The existing gas distribution network would need to be retained to ensure gas supply to the hybrid units. The volume of gas consumed would be significantly lower than using standalone gas-fired boilers.

---

[23] http://www.energysavingtrust.org.uk/northernireland/Organisations/Technology/Field-trials-and-monitoring/Field-trial-reports/Condensing-boilers-and-advanced-room-thermostats-field-trials

5.2.3.3 Electricity Infrastructure

The impact on the electricity distribution system will be dependent on the change in electricity demand (peak and total consumption) that will result from the implementation of the four different technology scenarios. In particular there will be significant increases in electricity usage in the following scenarios:

- Scenario 1 - Hybrid heat pumps and gas cooking
- Scenario 2 – Electric heat pumps and electric cooking

The conversion from gas cooking to electric cooking is likely to have an impact on the maximum electricity demand within any 24 hour period. Consideration would need to be given both to total energy consumed and to peak demand requirements.

The analysis methodology was based around scenario 2 where it is deemed that the combined electricity consumption of both electric heat pumps and electric cooking as having the greatest impact on the existing electrical network.

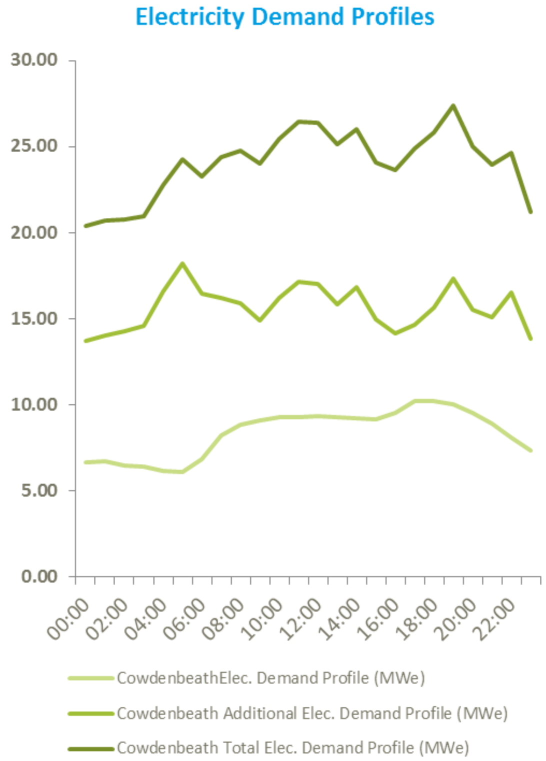


Figure 21 : Typical daily electricity demand profile for Cowdenbeath during peak heating season under deployment of EHP technology option

The capital costs associated with any necessary electricity distribution upgrade will be dependent on the peak demand that must be met.

The methodology for analysis of the electricity network capacity and upgrades required is provided in Appendix C.

To ascertain the level of reinforcement required to ensure the Cowdenbeath network is compliant with the UK Distribution Code, further analysis was required. This was performed in the following steps:

a) Apportion the ASHP demand on the basis of number of LV feeders per Grid Supply Point (GSP) per zone ASHP demand.
b) Assess the number of new GSPs that are likely to be over their rated capacity after apportionment.
c) Determine the amount of new GSPs and 11 kV and LV circuits required to avoid thermal loading issues on both the 11 kV and LV networks.

Of the additional electrical demand of 10.7 MW associated with deployment of heat pumps approximately 6.7 MW (63%) can be absorbed by the existing Cowdenbeath network. To supply the additional heat pump demand of 10.7MW (37%) extensive reinforcement of the Cowdenbeath/Lochgelly 33 kV, 11 kV and LV electrical networks would be required. The analysis identified that there would be around 26 secondary substations operating over their rated capacity following the addition of the new heat pump demand; some operating around 300% of rating and therefore requiring significant reinforcement.

11 kV Reinforcement

The analysis identified that the additional demand would require up to 30 new 0.5 MVA secondary substations (or Ring Main Units - RMUs) supplied by up to 15 km of 11 kV underground cable[24].

Low Voltage Reinforcement

The increase in capacity at 11 kV level would provide connections for around 60 km[25] of LV cable as well as requiring splitting of the LV network due to increased loading on each individual LV circuit and therefore a reduction in the number of customer connected to each circuit.

Electricity network high voltage (EHV) reinforcement

A new primary substation would be required as a result of splitting the 11 kV network between Cowdenbeath and Lochgelly and therefore the EHV reinforcement requirements include a new 33/11 kV 24 MVA primary substation and associated 33 kV cables to the Westfield GSP.

The amount of 11 kV and 33 kV is dependent upon many factors, in particular the sighting of the new PSS. For the purpose of the analysis it was assumed that the location would be in the Lochgelly area and therefore at least three 11 kV circuits of approximately 2 km in length would be required to cut and terminate existing circuits as well as connecting new 11 kV circuits onto the new PSS.

5.2.3.4 Electric Heat Pumps

For the main scenario it is assumed that the distribution temperature in homes will be lower than current practice to achieve higher efficiency (coefficient of performance) for heat pumps. To achieve this the model includes deployment of fabric energy efficiency as explained in Section 4.4.3.3. This is assumption does not apply to the other technology options.

---

[24] Assuming 500 m of 11 kV per secondary substation.

[25] Assumes four LV circuits of 500 m in length per RMU.

A summary of the electric heat pump solutions applied in the model to Cowdenbeath for each of the property types is listed in Table 17. The calculation of the coefficient of performance (COP) and the seasonal performance factor (SPF) is based on supplier data.

Table 17 : Electric heat pump solutions applied in the model to Cowdenbeath

	Avg. Heat Pump Size (kW)	Typical Heat Pump Type installed	Average SPF	Total Annual Electricity Consumption (MWh_e)
Office	**28**	**ASHP**	**2.89**	**852**
Education	**172**	**GSHP**	**3.71**	**1,546**
Residential	**5**	**ASHP**	**2.72**	**43,463**
Industrial	**19**	**GSHP**	**3.74**	**2,440**
Recreational	**88**	**GSHP**	**3.74**	**1,129**
Government	**119**	**GSHP**	**3.72**	**164**
Retail	**23**	**ASHP**	**2.88**	**2,165**
Restaurant/pub/bar	**19**	**ASHP**	**2.99**	**547**
Hotel	**6**	**ASHP**	**2.83**	**55**
Military	**-**	**-**	**-**	**-**
Health	**42**	**ASHP**	**2.92**	**492**
Public/Community	**37**	**ASHP**	**2.92**	**836**
Total				**53,687**

5.2.3.5 Hybrid Heat Pumps

The modelled hybrid heat pump option assumes that the unit is configured to supply the base space heating load from the heat pump with peaks (due to DHW and during low ambient external temperature) supplied by the gas boiler[26].

The share of fuel supply to space heating and hot water over an annual cycle to the HHP scenario is calculated in the model. Due to efficiency factors on the conversion technologies the proportion of heat supplied is shown below:

- Proportion of heat from boilers: 10%
- Proportion of Heat from Heat Pump: 90%

Each property is assigned a heat pump in the model according to the individual property demand. The results presented in Table 18 report the average solutions applied in the model for Cowdenbeath for each of the property types is listed.

[26] In a real installation the share of production of heat and hot water will depend on the settings in the individual property heating control, BMS as well as signals from external energy pricing.

Table 18 : Hybrid heat pump solutions applied in the model to Cowdenbeath

	Avg. Heat Pump Size (kW)	Typical Heat Pump Type Installed	Average SPF	Annual Electricity Consumption (MWh_e)	Annual Gas Consumption (MWh)
Office	18	ASHP	2.97	798	101
Education	112	GSHP	3.70	1,391	649
Residential	3	ASHP	2.70	37,720	18,196
Industrial	12	ASHP	2.96	2,643	1,450
Recreational	57	ASHP	2.98	1,003	1,375
Government	77	ASHP	2.89	200	35
Retail	15	ASHP	2.91	2,048	300
Restaurant/pub/bar	13	ASHP	2.96	514	126
Hotel	4	ASHP	2.71	44	40
Military	-	ASHP	-	-	-
Health	28	ASHP	2.92	451	135
Public/Community	24	ASHP	2.92	785	166
Total				47,597	22,572

5.2.4 District Heating Design

5.2.4.1 Low and Zero Carbon Generation Plant

One of the benefits of district heating is its compatibility with many potential energy generation plants, and associated low carbon technologies. The district heating network can accept heat from multiple sources provided they are compatible with the network specification requirements. In this study all of the technologies have been considered in combination with 100% back-up / top-up boilers to ensure efficient and reliable operation across the range of heat demands and to re-assure sufficient alternative heat supply to meet consumer demands at all times.

The technologies utlisied in the model are biomas boilers and water source heat pumps, further details of these technologies are described in Appendix A.

To provide flexibility in the model in terms of network size the following range of energy centre peak outputs are analysed (0.5 MW, 1 MW, 5.5 MW, 10 MW, 15 MW, and 20 MW). For each of these sizes of energy plants, 40% of the peak output is assumed to come from the selected LZC technology.

5.2.4.2 General Assumptions made for all Technologies

The following general assumptions apply to all technologies. The specific assumptions regarding the individual heat technologies are described in Appendix A.

- Thermal stores are sized on the following basis:
  - 30 °C Delta T (ΔT)
  - Volume; 20 litres per kW output from the energy centre (total ie. LZC + Top up)
  - Thermal store aspect ratio = 2.5
  - Thermal store located inside the energy centre for plant rooms ≤ 1 MW
- Offices area and welfare areas allowed for energy centres above 1 MW output
- Utilities average connection distance from the energy centres are assumed to be 100 m
- The energy centre location is provided with haul road access
- For all technologies the energy centre includes 100% back-up / top-up gas boiler plant
- When sizing the energy centres additional area is allocated within them for fuel handling, maintenance access and equipment replacement.
- No long term fuel storage or drying facility is included within the energy centres
- Back-up power generator is included

5.2.4.3 Main Scenario 1

For Cowdenbeath, the model considers the use of biomass boilers in combination with water source heat pumps. Other technologies are potentially available. It is a key assumption that there is a suitable water resource to provide water supply to the heat pumps. This primary generation is supported by natural gas boilers to meet back-up and peaking demand. As a result the energy centre would need to be located close to the gas transmission network which would be maintained. The distribution network within the town would be decommissioned. Cooking would be converted to electric cooking.

Table 19 : Main district heating generation plant details for Cowdenbeath

Plant Selection	Biomass Boiler	Water Source Heat Pump
Energy Centre Capacity (MW_{th})[27]	20	35
LZC Plant Capacity (MW_{th})	10	28
Thermal Efficiency	85%	Automatically calculated
Fuel Type	Wood Pellet	Electricity
Equivalent Thermal Store Size (MWh)	25	70
First Year of Operation	2030	2030

[27] Energy Centre capacity reflects the peak heat demand from the plant and LZC Plant Capacity is the capacity of the LZC plant.

5.2.5 District Heating Infrastructure

The pipe schedule and cost of the district heating pipe network infrastructure can be estimated in the model based on the linear length of the heat network and a cost per metre or modelled in hydraulic modelling software. In the scenarios modelled however, Ramboll used an in-house modelling tool, System Rørnet, to model the network to generate a pipe schedule which is inserted into the model and a cost associated. This is considered to provide a more robust assessment of the pipe diameters throughout the network since it relates the demands to the pipe velocities and pressures using standard hydraulic equations.

The route shown in Figure 14 was laid out in ArcGIS and followed the existing road network as much as possible. Major roads, railway lines and rivers were avoided. The most cost-effective method for supplying heat to both Lochgelly & Cowdenbeath was deemed to be from two networks that could be interconnected through Lumphinnans. The network was then analysed in Ramboll in-house hydraulic analysis software, System Rørnet.

5.2.6 Individual Property Interfaces

Each customer/property requires a metered connection to the heat network. The design of these varies depending on the property type and system temperatures and pressures. A typical connection may comprise a heat interface unit (HIU) which includes a heat exchanger to create a hydraulic separation between the secondary heating system and the main network. The HIU would also contain filters and a pump to supply the secondary system. The connection would be required to have a heat meter to record heat use. Heat substations would be installed for apartments to create block heating systems whereby a number of flats would be connected to a single heating circuit and do not have individual HIUs. The individual connections would be metered.

5.2.7 District Heating Development Trajectory

The development of the district heating network may not be practical or economically viable to come forward in a single phase. The capital intensive investment in the heat network and the need to commission in phases means that anchor heat loads and areas of high energy demand would be likely to develop first to create a number of small district heating networks (clusters) complete with their own energy generation plant. These cluster networks would be designed with the ability to be interconnected in the future making the phased approach of the town network more attractive/feasible with lower initial capital risk due to reduced network infrastructure cost.

The development trajectory for the main scenario assumes a phased deployment of district heating in the town as shown in Table 20. These specified dates influence the cashflow model to reflect the likely phasing of deployment within the town.

Table 20: Assumed phasing of development of district heating network by zone (refer to Figure 14)

Zone	Connection Year	Zone	Connection Year	Zone	Connection Year
1	2032	**9**	2039	**18**	2041
2	2036	**10**	2036	**19**	2038
3	2034	**11**	2034	**20**	2043
4	2036	**12**	2030	**21**	2043
5	2036	**13**	2036	**22**	2038
6	2039	**14**	2034	**23**	2045
7	2041	**15**	2036	**24**	2045
8	2039	**16**	2039	**25**	2043
		17	2037		

5.3 Low Temperature Scenario

The main scenario is based on customer heating systems operating at 82/71.

An additional variation on the main scenario is reported to consider the effect of low temperature solutions. Fabric energy efficiency measures and upgraded customer heating systems are required for the implementation of lower temperature district heating networks. This would reduce the network heat losses. It is also required to be compatible with a wider mix of low carbon heat generation technology including higher efficiency heat pump solutions.

The low temperature option is modelled as a variation on the main scenario based on investment in building fabric energy efficiency and operation of the alternative technology options under the low temperature option. Temperature assumptions for the low temperature scenario are given in Table 10.

5.4 Pilot Scenario

Cowdenbeath was selected as a typical town in the UK (Section 4.1). It is also interesting for this study due to its proximity to the Mossmorran Ethylene Plant which produces hydrogen as a by-product of its process. This is utilised in the plant as a fuel but could theoretically be used to demonstrate the principles of distributed hydrogen in a town network.

We therefore model this plant as a hydrogen supply to the town as a pilot scenario for hydrogen distribution at Cowdenbeath as an alternative for comparison to the main scenario. This assumes that the hydrogen is generated at the Mossmorran ethylene plant, located approximately 2km to the south of Cowdenbeath, and supplied to the network. This plant would require investment to enable hydrogen to be streamed off and cleaned for distribution.

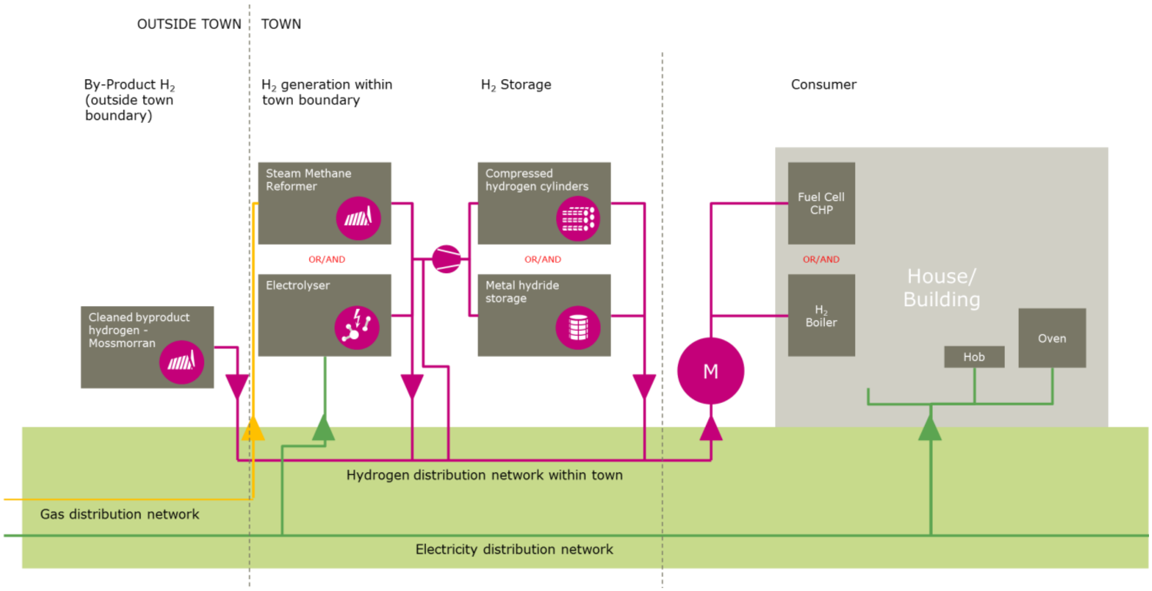


Figure 22 : Illustration of the 100% hydrogen system in the pilot scenario showing principal production at Mossmorran with potential options to include storage, backup and peaking generation within the town – the modelled scenario assumes 100% of hydrogen comes from Mossmorran.

The hydrogen is currently used as a fuel in the plant and so is not a "waste product". The plant at Mossmorran offers a potential source of hydrogen for a pilot demonstration project, however other fuel could be supplemented to the industrial process in that case and so the calculation of the carbon emissions associated with this scenario are included based on the methane fuel input and the conversion efficiency.

For the purpose of modelling this solution in the pilot scenario, carbon capture and storage (CCS) is not included. Such a demonstration project could prove the practicality of switching to hydrogen, but would not deliver carbon savings.

Under the pilot scenario, where Cowdenbeath operates as an island network distributing 100% hydrogen, the storage volume within the town would not be able to benefit from line packing the UK national grid infrastructure. Local gas storage to provide balancing supply for peak demands is necessary. The model assumes that storage is provided through compression in cylinders.

Other options and the economic benefit of these alternatives would need further investigation during the detailed design and development of a business case.

Table 21: Assumptions for pilot scenario

Key Assumption	Value	Units	Explanation
Boiler efficiency	85.00	%	Assumption advised by BEIS.
H2 Boiler Costs under pilot scenario	Varies 35kW: £8,900 1MW: £170,000	£	Data from Logan Energy. Varies according to size.
Hydrogen storage	730.50	£k/MW	Cost of storage based on a compressed cylinder storage and capacity is assumed to be comparable to storage with DH system (20 l/kW capacity) 50% storage capacity in gas network and 50% provided at generation site.

6. COST METHODOLOGY

One of the key outcomes from the modelling approach is to investigate the comparison of costs for the alternative heat options.

In order to develop the cost models, the methodology and approach has followed Turner & Townsend's Cost Management Target Improve and Control (TIC) process.

Target – a "top down" cost estimate based on the design of the main plant and equipment. The cost plans are based on benchmark data available within cost databases and have, in some cases involved discussions with suppliers in order to narrow the cost profile of specific technologies. Cost planning models are used to build a cost plan for each of the research options and schemes, drawing upon specialist suppliers' knowledge, the basis of design, and benchmarking.

Improve – The cost plans align the options to the high level design requirements. The model takes into account variations in output for all the technologies and the cost plan has established the cost trajectory to be followed by the various design configurations.

Control – The cost plans also include the development of total operating cost of each system. This includes replacement and day to day maintenance estimates.

The cost plan structure reflects the research options, and is structured using Turner & Townsend's standard RICS compliant cost plan structure, which allows for an appropriate level of detail and granularity in the costs, in line with the design available. The cost plan is built into the cost database in the model to provide the reference costs for all scenarios.

Contractor costs are based on benchmark data available from Turner & Townsend databases.

6.1.1 Cost Trajectory

A high level assessment of potential cost trajectories of the technologies analysed for the investment was also built into the model. The results indicate a view of how external factors could influence the costs of the technologies in future as follows:

- As some technologies become more readily available and widely adopted, they will be produced at much larger volumes and across a wider range of locations. Therefore, as these technologies become more sought after, commercial influences will see a reduction in costs.

- The above will be true for most of the technologies in the report; however, whilst the more innovative technologies are still going through the research and development phase, their costs are unlikely to reduce and might even see increases.

- Many of the technologies are made using metal components – and they are therefore subject to the influence of materials commodities markets – as the price of steel fluctuates for example, so does the output materials prices.

- As raw materials are demanded more, there will likely be medium to long term rise in materials costs, which will in turn mean output costs could increase for sustainable technologies.

A simple technology maturity approach was used to estimate total cost reduction over time. Assumptions were made on the overall cost degression over 40 years. The degression is assumed to follow a logarithmic relationship to take account of the majority of the cost reduction happening in the first 10-20 years ie. a typical experience curve.

The cost degressions assumed in the model are reductions on the overall CAPEX of the energy centre and the reductions in the table below account for the fact that there are substantial parts of these systems where little or no cost reduction (ie building, balance of plant, back-up plant, storage, distribution equipment) would apply. The cost reduction factor on the key equipment will therefore be proportionally higher than these figures quoted below.

Table 22: Cost degression assumptions for technology options selected over 40 years

Technology	Maturity	Cost degression modelled over 40 years
Biomass Boiler	Medium	20%
ASHP	Medium	20%
GSHP	Medium	20%
Natural Gas Boiler	High	0%
Water Source Heat Pump	Medium	20%
Steam Methane Reformer	High	0%
Hydrogen Storage	Medium	20%
CCS	Low	40%

6.1.2 Life Cycle Cost Profiles

The data base includes costs over 60 years, however the model includes a life cycle cost calculation over a 40-year profile. The life cycle cost analysis was conducted in accordance with the process outlined in PD 156865:2008 (BSI, 2008) and includes:

- Capital replacement allowances (life cycle replacement profiles)
- Maintenance costs
- Energy costs (as calculated by Ramboll)

6.1.2.1 Capital Replacement Allowances

The life cycle cost (LCC) replacement profiles are based on the capital costs information developed by Turner & Townsend. The individual capital costs are taken as the base cost to which quantity adjustment, preliminaries and work in existing assets factors are applied in order to establish the cost of the replacement tasks.

- Quantity Adjustment Factor: Different parts of a system will have a different lifecycle and replacement cost. This factor is a percentage of the capital cost allocated to individual elements that are most likely to be replaced on a life cycle perspective. The factors are generally based on benchmark data, industry standards and Turner & Townsend's expertise. Factors are considered to be as realistic as possible by analysing the nature of the component.

- Preliminaries: This cost is applied as a percentage to supplement replacement cost calculated from the quantity adjustment factor and capital cost. Preliminaries cover the on-costs that a contractor may incur during the major maintenance activity. This allowance covers for additional management costs and design fees that are expected to be present when processing the administrative work for maintenance activities.

- Life cycle risk and management fee allowances: A 5% allowance has been included for life cycle risk which is typically allowed for if component failures occur in untimely intervals and with varying levels of consequences. This contingency percentage addition is made to the overall cost of maintenance for the building elements for every year.

The core principles of LCC planning are encapsulated by the prediction of the most realistic future outcome in terms of quantum of major maintenance expenditure that will be incurred but more importantly; when this expenditure will have to be met.

Predicting the service life of each component allows the cash flow to be generated and provides the basis to "when" major maintenance will be required.

The life cycle cost data focusses on replacement of key elements and hence should identify major areas in which the network developer incurs cost. The model is based on Turner & Townsend data, and in addition a wide range of asset replacement costs and component service/replacement life data from various sources including but not limited to:

- Building Cost Information Service (BCIS) and Royal Institution of Chartered Surveyors (RICS);
- BMI life expectancy of building components;
- Chartered Institution of Building Services Engineers (CIBSE);
- Building Services Research and Information Association (BSRIA);
- Manufacturers guidance and,
- Internal benchmark database of components/system life expectancies (LifeTTime).

Our output model, based upon current design details is of the order of +/- 30% accuracy. This uncertainty can be modelled in the sensitivity module in the model.

6.1.2.2 Maintenance Costs

The operation and maintenance (O&M) costs cover the day-to-day spend to ensure that the facility operates smoothly; typically the O&M costs cover the following spend areas:

- Planned preventative maintenance (PPM)
- Reactive maintenance estimates
- Administrative management costs

The operating and maintenance strategy for the systems will vary according to specifications. At the level of analysis required in the model, it is assumed that maintenance services will be delivered according to activities and frequencies stated in the industry recognized 'SFG20'[28] standard and manufacturer's recommendations. In building the maintenance assumptions we have therefore relied on published data and benchmark databases.

[28] 'Service and Facilities Group', a specialist group within the Building Engineering Services Association who own and are responsible for the up-keep of the SFG20 standard maintenance specification for building engineering services.

7. RESULTS

The analytical results from the model are presented in the following section. These are based on the modelled scenario described in Section 5.2. This demonstrates the lifecycle costs of a typical medium sized town investing in the technology options selected respectively. The main scenario assumes that the project is undertaken as part of a national roll-out of the technologies concurrently with the deployment in Cowdenbeath. This scenario benefits from large scale uptake of technologies and the resulting economies of scale that are anticipated. The sensitivity of this scenario to variations in capital and operational cost assumptions are also discussed.

The model reports the discounted net present cost over a 40 year period at a discount rate of 3.5%[29] and the results presented in the following chapter are presented in real terms from 2030. The model calculates a schedule of the installed costs for each of the solutions investigated based on the methodology and assumptions described in Section 3. This cost includes all the "in-scope" component costs for generation, distribution and customer interface to represent a realistic deployment of the technology. The elements of cost that are outside the scope relate to costs associated with increasing capacity of the main transmission networks and generation for gas and electricity.

The installed costs are broken down in terms of CAPEX for equipment and installation and other administration/procurement/management costs and scheduled according to the required period of investment.

For the various technologies the duration and profile of the infrastructure investment varies significantly. All solutions assume continuity of heat supply from gas boilers, including their lifecycle replacement, during the period between now and full deployment of the infrastructure solution (assumed in the model to be 2030). The subsequent deployment of Hydrogen and DH infrastructure would require customer systems to be replaced concurrently with deployment to be compatible. DH would be installed over a number of years in phases. Hydrogen would require isolation and conversion of the town system in a shorter period. For EHP and HHP solutions the lifecycle replacement of units would occur following the change of policy and so gas boilers would be replaced over an estimated 15 year replacement cycle.

A key feature to note is that there is minimal network cost associated with the hydrogen scenario since the investment in conversion to plastic pipe is already committed by SGN. In addition, the existing network has been modelled as part of this study and is expected to have sufficient capacity to deliver the required quantity of hydrogen to customers.

The fuel costs for each of the scenarios are based on BEIS fuel price projections (DECC, 2015) and these projections are not forecast beyond 2030 and so the model assumes that fuel prices stabilise in real terms from 2030.

The results of the lifecycle cost are included in the following Sections and illustrate the comparison between the scenarios.

---

[29] This is a simplification for the model and applies 3.5% discount rate over the 40 year lifecycle. Please note that the Green Book requires a 3.5% discount rate between 0 and 30 years, then 3.0% between 31 and 40 years. This approach can be adjusted for detailed financial modelling.

The results include a breakdown of costs for each of the technology options. The results of the scenarios are presented in this report to show the share of lifecycle cost under the following categories and the description of what parts of the infrastructure are included is explained in Table 23 below.

Table 23: Description of what is included in the lifecycle cost for each category for comparison of cost for each technology option

Category	Element	District Heating	EHP	HHP	H2
Primary Generation	**Generation**	Energy centre including fuel supply, back-up generation	Electricity supply from the DNO infrastructure	Electricity and gas supply from the distribution infrastructure	Levelised cost of hydrogen generation.
	Storage	Thermal storage	Not included	Not included	Hydrogen storage locally using cylinder storage.
	CCS	Not applicable	Not applicable	Not applicable	Carbon capture and storage
Infrastructure	**Transmission**	Not included	Not included	Not included	Not included
	Distribution (within town)	District heating network installation and heat losses.	Electricity distribution network upgrade and maintenance	Electricity distribution network upgrade and maintenance of electricity and gas distribution networks.	No cost included for gas network upgrade. Includes network operation and maintenance.
Customer Interface	**Customer Interface**	Heat interface unit, fabric/ heating system upgrade, Electric ovens and hobs	Heat pump, fabric/heating system upgrade, Electric ovens and hobs used.	Heat pump, fabric/heating system upgrade, Electric ovens and hobs used.	Replacement hydrogen boiler, electric ovens and hobs

7.1 Main Scenario Results

For each technology solution below the following outputs from the 40 year lifecycle model, based on a starting year of 2030, are presented:
For each technology solution and scenario below the following outputs are presented and compared:

- Cash flow graphs for each of the technology options considered;
- Discounted net present cost of the solution in £/MWh of heat delivered; and
- Carbon emissions reduction compared to BAU over lifecycle; and
- Discounted net present cost per tonne of carbon saved over lifecycle.

7.1.1 Hydrogen

The hydrogen scenario follows the business as usual cashflows in the years prior to 2030 since existing boilers and heating systems will remain until the deployment of hydrogen boilers. The implementation of the hydrogen solution will require changes to regulation and a wholesale replacement of boilers. It has been assumed that in 2030 policy will require manufacturers of boilers to phase out conventional boilers and supply hydrogen boilers. Dual fuel enabled boilers[30] could be regulated prior to this to phase the investment, however that has not been modelled. The model assumes that hydrogen boilers will be installed as replacement to existing boilers from 2030. The conversion to a hydrogen supply will occur in 2030 and will coincide with a full upgrade of these boilers in Cowdenbeath.

The cashflows show a spike in initial capital cost at the changeover in 2030. The lifecycle costs thereafter stabilise since the ongoing costs relate to hydrogen supply and operation and maintenance. The main costs associated with the deployment of a 100% hydrogen supply to Cowdenbeath are:

- Capital cost for replacing boilers in individual properties with hydrogen boilers; and
- Operational fuel costs for wholesale hydrogen purchase.

(£'000)	2030	2030-2044 2046-2059 2061-2070	2045 & 2060 (replacement)
Cost of Upgrading the Gas Grid to H2	£2,522	-	-
Replacement of Gas Hobs & Ovens	£4,412	-	-
H2 Boilers CAPEX/REPEX	£36,713	-	£36,713
Removal of Gas Meters	£680	-	-
H2 Meters (incl. Installation Costs)	£8,486	-	-
Cost of FEE and Heating System Upgrade	-	-	-
H2 Grid - Sinking Fund	£521	£521	£521
Sub Total	**£53,336**	**£521**	**£37,234**

Table 24: Itemised capital investment costs for hydrogen scenario in the early years of the deployment (all figures are in £ '000s)

(£ '000)	2030	2031-2070
H2 Boilers Maintenance	-	£1,816
Hydrogen - Fuel Consumption	-	£8,337
Consumers' Gas Boilers Fuel Consumption - Pre Full Deployment	£4,805	
Maintenance Cost of H2 Network	-	£252

Table 25: Itemised operational costs for hydrogen scenario in the early years of the deployment

[30] Dual fuel boilers will be capable of running on natural gas and switching to hydrogen (this is likely to be achieved through a physical replacement of burners, however in a boiler that is designed for this replacement to be done quickly by a qualified gas engineer.

The net present cost for the deployment of 100% hydrogen supply across all zones is estimated in the order of £49.9/MWh. The model results shows a large spike in initial capital costs as a result of the rapid replacement of natural gas boilers to hydrogen equivalents and is of an order of magnitude greater compared to the electric and hybrid heat pump scenarios which are phased over the lifecycle replacement of individual boiler plant.

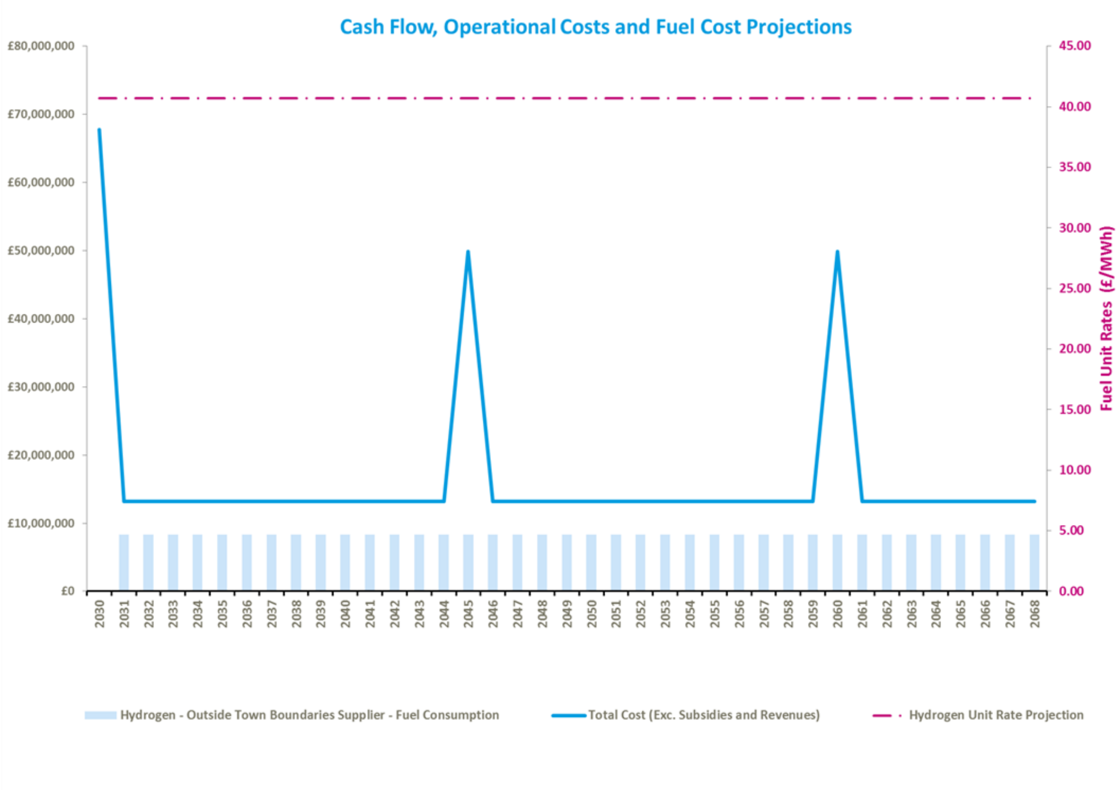


Figure 23 : Discounted cashflows of hydrogen scenario

7.1.2 District Heating

The district heating scenario shows a spike in initial capital cost (Figure 24) that is similar to the hydrogen scenario. The lifecycle profile thereafter is quite different since the main infrastructure asset (the district heating pipe network) investment is phased and expected to have a long life time and would not require replacement or major maintenance during the 40 year model period. The main costs associated with the deployment of a district heating network in Cowdenbeath are:

- Cost of installation of district heating network infrastructure;
- Capital cost for replacing boilers in individual properties with heat interface units;
- Capital cost of energy centre; and
- Operational fuel costs for heat production at the energy centre.

The net present lifecycle cost for the deployment of district heating across all zones is estimated in the order of £48.3/MWh. This varies by zone and that relationship is further discussed below.

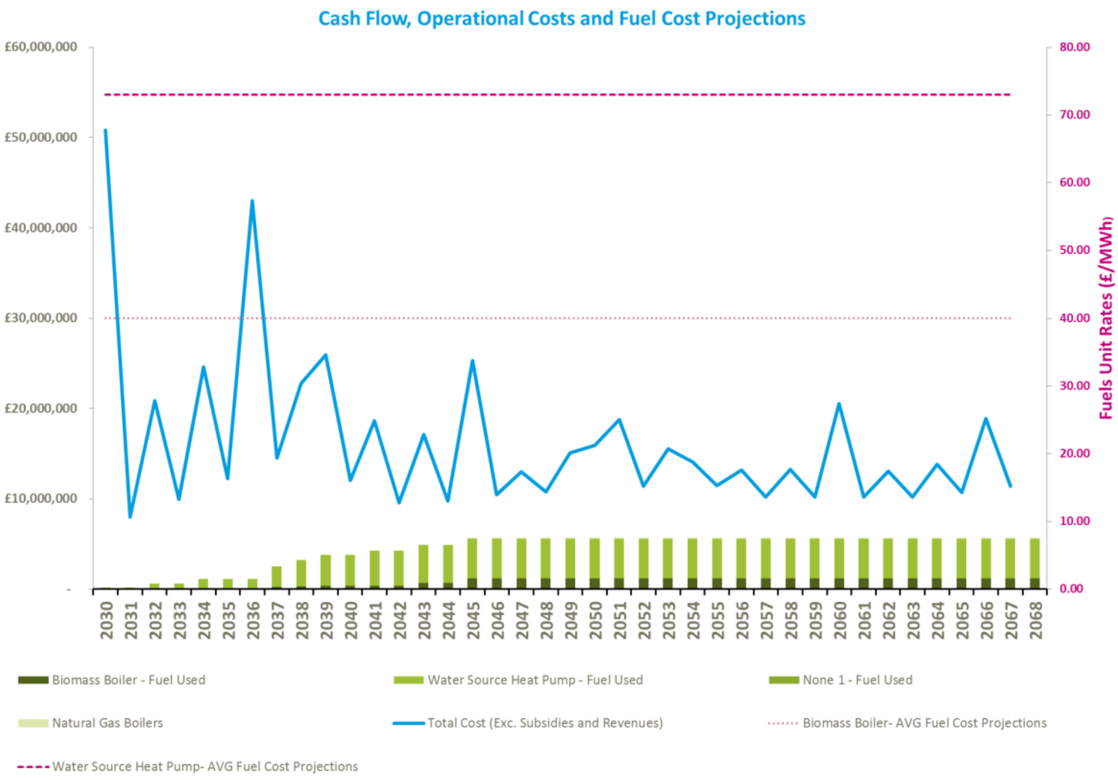


Figure 24 : Discounted cashflows of district heating scenario

7.1.3 Heat Pumps

The main costs associated with the deployment of electric heat pumps in Cowdenbeath are as follows and these are shown in Table 26:

- Capital cost of fabric energy efficiency measures so that individual properties are compatible with lower flow and return temperatures to maximise the efficiency of the heat pump while maintaining thermal comfort;
- Cost of installation of heat pumps and lifecycle replacement of heat pumps;
- Capital cost for upgrading the electricity network; and
- Operational costs for electricity supply.

Table 26: Capital costs (£,000s) for heat pump replacement over first six years of transition to EHPs

£ '000	2030	2031	2032	2033	2034	2035-2070
Office	17	19	70	17	19	Costs vary
Education	-	34	17	-	34	
Residential	589	1,921	3,346	589	1,921	
Industrial	-	-	-	-	-	
Recreational	-	-	-	-	-	
Government	-	-	-	-	-	
Retail	56	122	70	56	122	
Restaurant/pub/bar	-	-	-	-	-	
Hotel	-	-	-	-	-	
Military	-	-	-	-	-	
Health	-	-	-	-	-	
Public/Community	-	-	57	-	-	
User Defined	-	-	-	-	-	
Office	-	-	-	-	-	
Education	-	-	-	-	-	
Residential	-	161	-	-	161	
Industrial	57	1,154	970	57	1,154	
Recreational	-	-	-	-	-	
Government	-	-	-	-	-	
Retail	941	-	321	941	-	

£ '000	2030	2031	2032	2033	2034	2035-2070
Restaurant/pub/bar	-	-	-	-	-	
Hotel	-	-	-	-	-	
Military	-	-	-	-	-	
Health	235	-	-	235	-	
Public/Community	-	-	-	-	-	
User Defined	-	-	-	-	-	
Replacement of Gas Hobs & Ovens	38	113	209	38	113	
Upgrading of Electrical Grid	-	-	-	-	-	
Decommissioning of Gas Grid	34	106	194	34	106	
Cost of FEE and Heating System Upgrade	204	476	850	204	476	
Immersion Heaters and Hot water Tanks	30	44	15	30	44	
Electrical Grid - Sinking Fund[31]	-	-	-	-	-	
Sub Total	**2,202**	**4,149**	**6,118**	**2,202**	**4,149**	**Varies – max. £21,666**

The overall cost of reinforcement for 10.7 MW of additional load is estimated to be £8.4 million[32] or £785,000 per MW as shown in the incremental cost per MW graph in Figure 25.

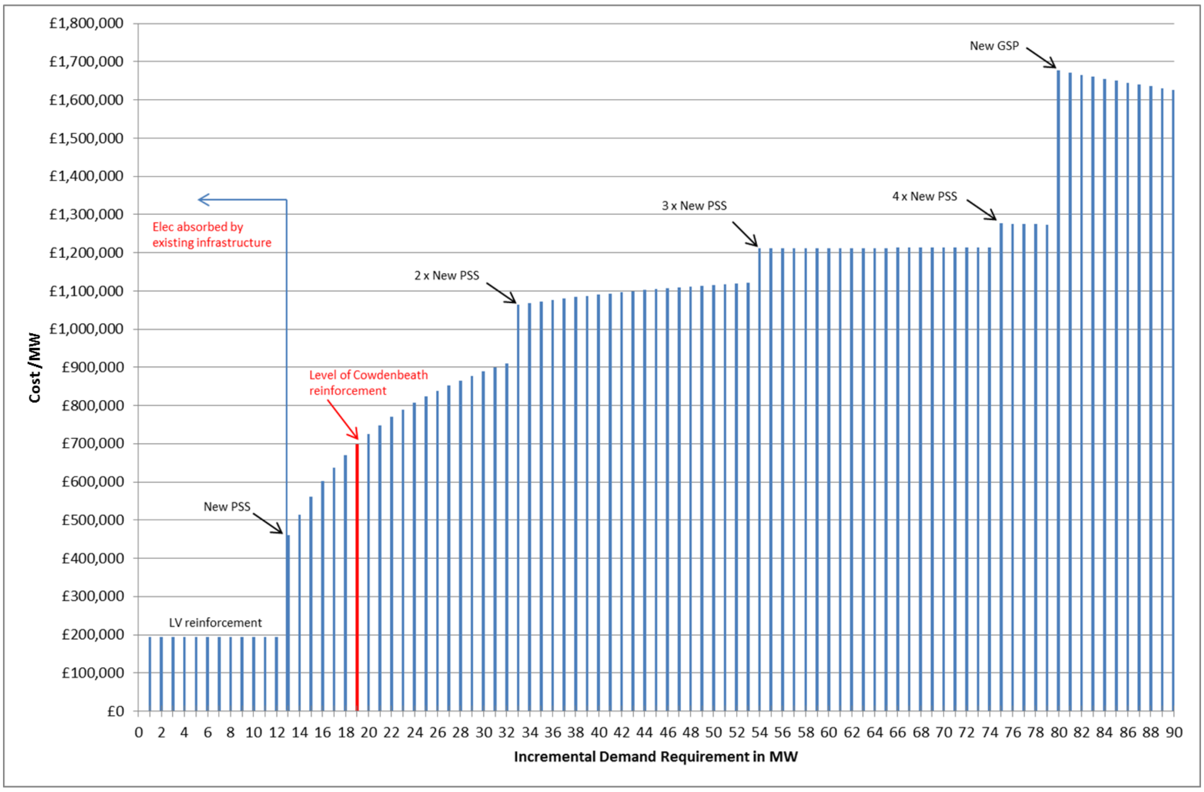


Figure 25 : Cost per MW electrical grid reinforcement graph based on requirements for Cowdenbeath based on algorithm developed by Ramboll during this study

---

[31] Electrical grid sinking fund (annualised replacement cost applied to the cost of the increased capacity and not the full BAU network replacement) starts after grid reinforcement

[32] The costs are inclusive of all costs relating to construction, installation and commissioning.

7.1.3.1 Summary of Cost Analysis for Electric Heat Pumps

The net present lifecycle cost for the deployment of electric heat pumps across all zones is estimated in the order of £52.4/MWh.

The graph included in Figure 26 shows that the non-discounted cashflows is dominated by the cost of installation of the heat pump and fabric energy efficiency measures. The model recognises the technical requirement to take significant steps to upgrade property heating systems or insulation measures to maintain thermal comfort with flow and return temperatures that are compatible with a high efficiency heat pump.

The consequential effect of this heat demand reduction is that the increased electricity demand to the town increases by less than under a condition with no fabric energy efficiency reduction. This minimises capital costs of electricity network upgrades as well as operational fuel costs for electricity.

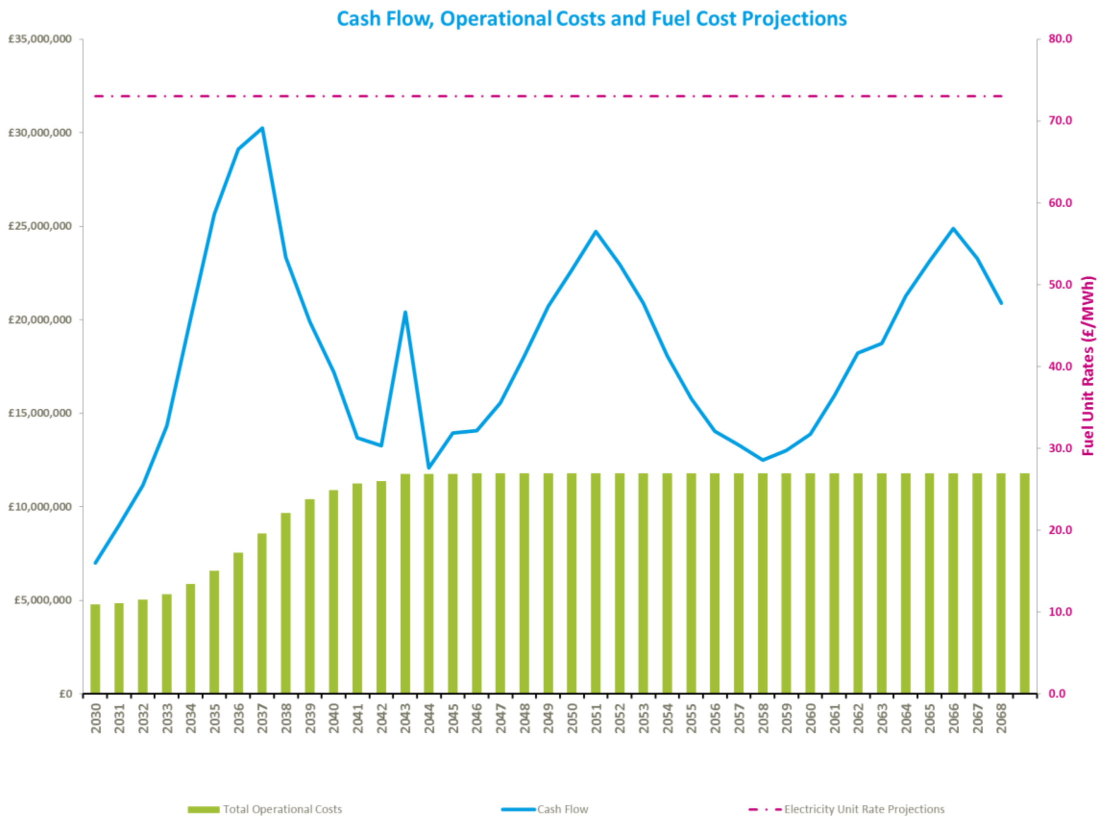


Figure 26 : Non-discounted cashflows of electric heat pump scenario

The lifecycle cost profile for EHPs is characterised by a peak cost in the short term to cover the costs of network upgrades, fabric energy efficiency upgrades and replacement of boilers with heat pumps at end of life. This is followed by a second peak that occurs when the electricity grid upgrade occurs. Thereafter the costs follow a waveform that reflects the repeated replacement costs of heat pumps.

7.1.3.2 Hybrid Heat Pumps

The net present lifecycle cost for the deployment of hybrid heat pumps across all zones is £43.7/MWh.

Similarly to the electric heat pump scenario the graph included in Figure 27 shows that the non-discounted cashflows are dominated by the cost of installation of the hybrid heat pump and fabric energy efficiency measures.

The capital cost of deployment of hybrid heat pumps is less than the electric heat pump scenario, principally due to the lower cost associated with using smaller heat pump units and lower diversified peak demand impact on the electricity network upgrade.

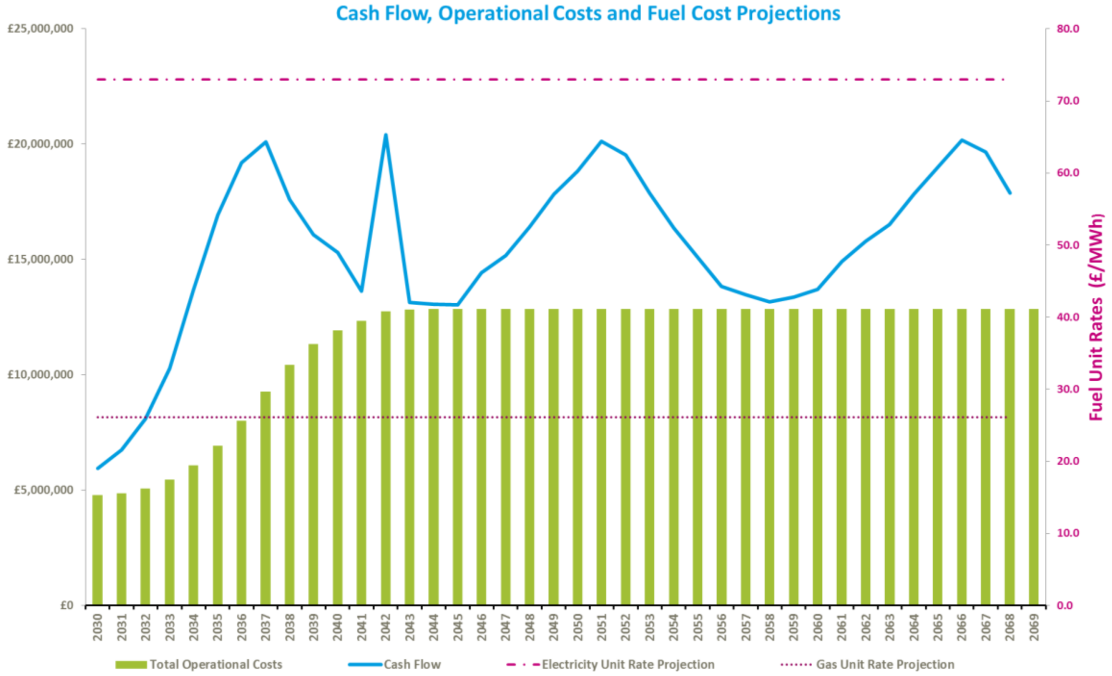


Figure 27 : Non-discounted cashflows of hybrid heat pump scenario

7.1.4 Comparison of Technology Solutions

The capital investment and deployment of the solutions is modelled to occur in 2030 for hydrogen but phased between 2030 and 2045 for all other technologies. This will depend upon market uptake following changes to policy and infrastructure investment in the technology roll-out.

The results are presented in terms of the total net present cost (NPC) for each of the technology options considered, and is shown in Table 27. This indicates that the lowest NPC for the solutions modelled is offered by the HHP solution with the other three technology options within 5% of one another. The remaining technologies are, in order of increasing NPC: DH, Hydrogen, and EHP.

The categories of the costs are described in Table 23 and it is informative to observe how the infrastructure investment is shared between generation equipment, infrastructure and customer equipment. The results are shown comparatively in Table 27, and illustrate how the cost is apportioned between primary generation, infrastructure and customer interface for each of the technology solutions. It also shows the carbon emissions reductions of the four scenarios in terms of total carbon saving over the lifetime.

	NPC (£/MWh)			
	H2	DH	EHP	HHPs
Primary Generation	£ 30.5	£ 24.4	£ 13.3	£ 13.0
Infrastructure	£ 2.6	£ 13.7	£ 2.1	£ 1.3
Customer Interface	£ 11.5	£ 14.3	£ 37.5	£ 29.9
Total NPC	£ 49.9	£ 48.3	£ 52.4	£ 43.7
CO2 Reduction over 39 years from now - (Tonnes)	1,608,156	1,303,290	1,468,127	1,368,241
CO2 reduction from BAU (%)	87%	70%	79%	74%
NPC per tonne of CO2	£ 222.9	£ 266.3	£ 256.4	£ 229.1

Table 27 : Breakdown of cost and carbon emissions reductions for each of the technology options considered. Carbon emissions reductions are against a BAU lifecycle emissions of 1,857,000 tonnes

The lowest net present cost (NPC) for the solutions modelled is offered by the hybrid heat pump solution. The technology solutions are not presented in the table in a merit order. The net present cost of the four technology solutions are all within 20% of the lowest.

It is worth noting that the infrastructure cost for national generation and transmission network upgrades for a national hydrogen grid and electricity network have not been included. This cost of upgrading generation and transmission infrastructure is not accounted for in the model which is a recognised limitation. This will affect each technology differently and would need to be factored into a full business case for these solutions.

For the hydrogen solution the costs are apportioned principally to the primary generation and customer interface cost with a lower infrastructure cost due to the reuse of the existing gas network.

District Heating costs are proportionally higher for primary generation than infrastructure and customer interfaces which are similar in magnitude.

The EHP and HHP scenarios show similar distribution of costs, however the total lifecycle costs are lower for HHPs. The electricity wholesale cost represents the majority of the cost of primary generation. The infrastructure cost is a small proportion of the total (3-4%) while the majority of the costs are associated with the heat pump in the customer property as well as fabric energy efficiency upgrades and replacement cooking equipment.

The cashflow curves for each of the solutions show very different profiles. These curves are compared in Figure 28 and illustrate that there are high initial costs for the hydrogen scenario reflecting the fact that it continues with the business as usual until 2030 and all investment occurs in a single year. The upfront costs of infrastructure for the heat pump scenarios are low in the early years since they follow the lifecycle replacement of boilers. District heating capital investment costs are high in year 1 and fluctuate with the expansion of the DH network infrastructure in the town.

The hydrogen scenario shows a significant spike in cost at the switchover date. This spike could be made less abrupt if a dual-fuel boiler policy could be brought in earlier, or to replace with dual fuel boilers from 2030 and for the conversion to 100% hydrogen to occur later.

The medium to long term costs reflect the fuel costs for each of the solutions combined with the replacement costs of individual customer interfaces and primary generation plants.

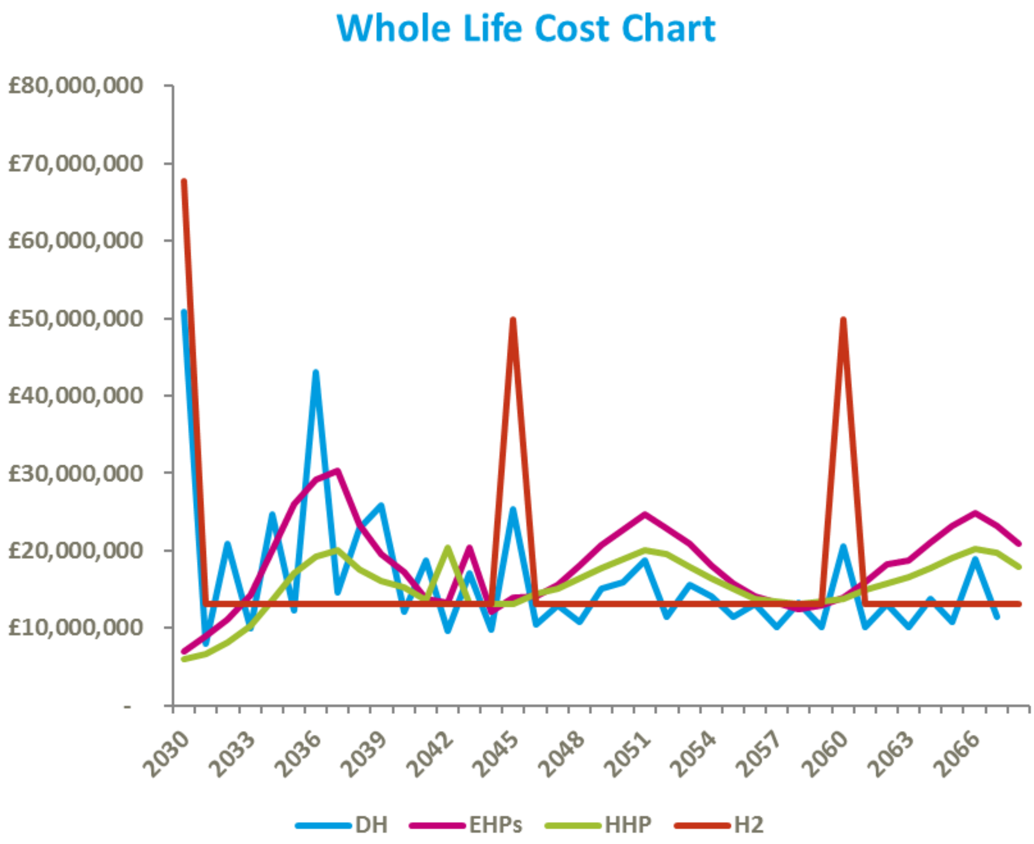


Figure 28 : Lifecycle cost graphs for comparison between each of the technology solutions

7.1.4.1 Comparison by Zone

The results of the model have also been compared and analysed across the twenty-five zones identified in Cowdenbeath. This analysis is simplified and is based on sharing the costs of generation and infrastructure according to the proportion of heat demand in the zone to the total town demand. The customer interface cost is shared across zones according to the proportion of customers within each zone compared to the total number of customers.

The results in terms of NPC are shown in Table 28.

Table 28 : Comparison by zone of the net present cost per MWh of heat demand

Zone	Description	NPC[33] / MWh heat supplied (£/MWh)				LHD[34] (MWh /m)	AHD[35] (MWh /Ha)
		H2	DH	EHPs	HHPs		
Zone 1	Cowdenbeath High Street - Commercial/ Residential & Large Morrisons Supermarket	£50	£47	£55	£44	3.2	298
Zone 2	Thistle Street Industrial Estate - Light Industry	£44	£41	£63	£45	9.0	260
Zone 3	Bridge Street Residential - Council Semi-Detached, 2-up 2-down, & Cowdenbeath Primary School	£51	£49	£52	£44	3.3	397
Zone 4	Residential mixture - older/newer bungalows & St. Brides RC Primary School	£51	£52	£51	£43	2.3	301
Zone 5	Broad Street Residential - local authority semi-detached - 2 up, 2 down	£54	£50	£54	£45	3.8	375
Zone 6	Woodend Industrial Estate - Medium Industrial	£44	£45	£58	£41	5.4	163
Zone 7	Hill of Beath - Residential Terraced, Light Industrial, & Hill of Beath Primary School	£50	£51	£52	£43	2.4	163
Zone 8	Residential - Terraced and Council Semi-Detached	£51	£47	£49	£43	2.5	391
Zone 9	Gateside Industrial Estate - Food manufacturer & Light Industry	£41	£41	£58	£44	7.7	187
Zone 10	Stenhouse Road Residential - Mix of old & new semi-detached properties & bungalows with green space	£52	£57	£52	£44	2.3	272
Zone 11	Residential - Council owned semi-detached & local Police Station	£49	£51	£50	£42	3.3	314
Zone 12	Cowdenbeath Football Stadium and Leisure Centre	£40	£37	£44	£38	9.0	611
Zone 13	Beath High School & Residential - Mix of semi-detached and terraced	£49	£46	£52	£44	3.2	277
Zone 14	Foulford Residential - Mix of terraced and detached housing & Foulford Primary School	£50	£56	£50	£43	2.0	233
Zone 15	New Residential - Modern detached housing and new developments	£49	£47	£50	£43	2.5	243
Zone 16	Glenfield Industrial Estate - Light Industrial	£48	£56	£55	£43	2.5	198
Zone 17	Residential & light commercial - Semidetached housing & Lumphinnans Primary Community School	£53	£57	£53	£45	2.4	239
Zone 18	Residential & light commercial - Semidetached housing & small number of flats	£51	£48	£51	£43	3.9	338
Zone 19	Residential - Council semidetached housing, small no. of flats, Lochgelly West & North Primary Schools	£54	£51	£54	£45	2.6	323
Zone 20	Residential Mixed - Modern detached housing & new developments	£48	£49	£48	£41	2.6	216
Zone 21	Lochgelly South - Residential Semidetached housing & Lochgelly South Primary School	£51	£49	£51	£43	3.3	396
Zone 22	Lochgelly High Street - Commercial & small number of flats about high street shops	£48	£43	£54	£43	4.5	616
Zone 23	Lochgelly East - Modern detached residential and some light industrial	£48	£46	£49	£42	3.2	190
Zone 24	Lochgelly North - Residential mixture of semi-detached & bungalow	£49	£46	£52	£43	3.4	167
Zone 25	Cartmore Industrial Estate - Light Industrial & Lochgelly High School	£41	£38	£53	£42	6.1	170
Town Wide		**£50**	**£48**	**£52**	**£44**		

It should be noted that there are various uncertainties, risks and sensitivities in the cost data and so the figures presented by zone should be treated as indicative of performance rather than absolute.

---

[33] NPC presented at 3.5% discount rate

[34] LHD is the linear heat density and is represented by the overall annual heat demand per m of installed district heating pipe trench length (units are MWh/m). LHD is a useful indicator of the economic performance of district heating networks.

[35] AHD is the area heat density in units of MWh/m²

The comparison of the NPC across the zones provides a useful dataset to infer some indicative KPIs for other towns in the UK. Figure 29 indicates that hydrogen and district heating costs fall with increasing linear heat density. The NPC of EHPs appears to increase with linear heat density and HHPs appear to be unaffected by linear heat density.

The NPC for HHP solutions are lowest across most zones (Table 28). Zones 2, 9, 12 and 25 suggest that DH offers the lowest NPC. These zones have a LHD of >5 MWh/m. Zone 22 shows that the NPC of HHP and DH is equal and this has a LHD of 4.5 MWh/m.

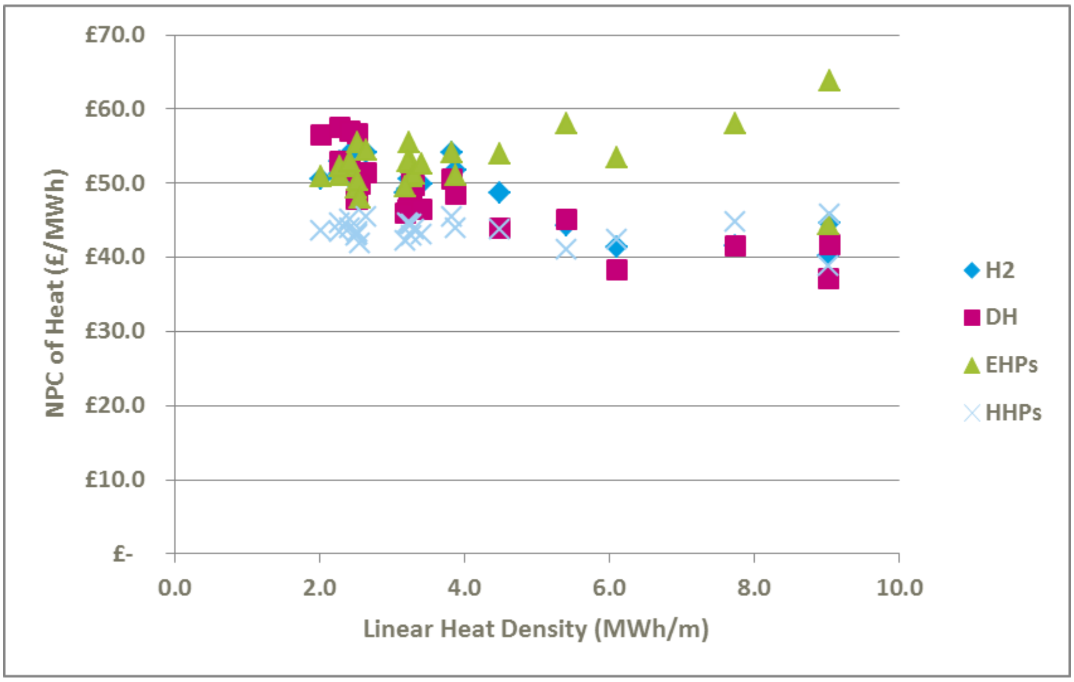


Figure 29 : Comparison of net present cost with linear heat density

The NPC for the DH solution reduces with the linear heat density, since higher linear heat density reduces the share of cost of pipe network infrastructure per unit of heat delivered. High heat density is commonly recognised as a benefit for DH projects. The NPC for the hydrogen solution reduces with the linear heat density, since higher linear heat density is probably representative of larger consumers. The modelled capital cost per kW associated with hydrogen boilers reduces dramatically with scale as indicated in Figure 30.

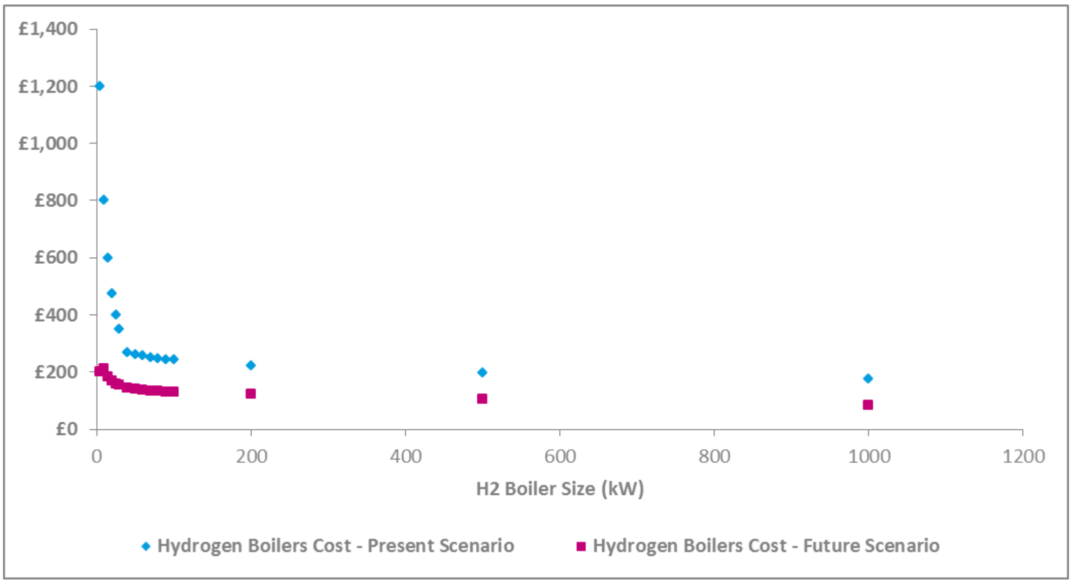


Figure 30 : Hydrogen boilers- Capital cost per kW of installed capacity included in the cost assumptions developed by Logan Energy for the model.

The electric and hybrid heat pumps options would also be affected by the modelled variation in capital cost per kW which reduces larger sizes (Figure 31). As a consequence there is no clear relationship between NPC and linear densities for the electric and hybrid heat pump options.

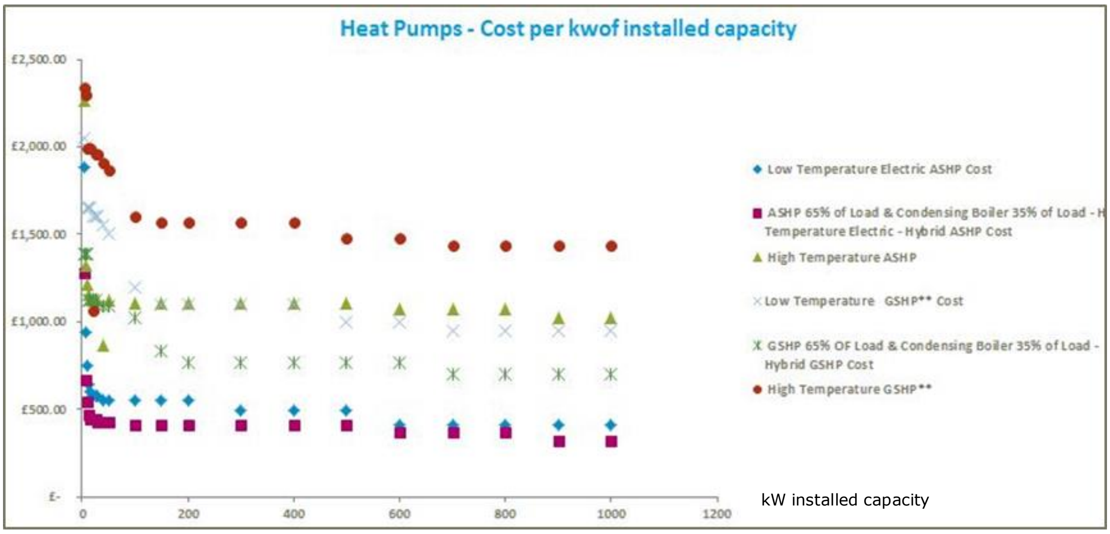


Figure 31 : Heat pumps - Cost per kW of installed capacity

7.1.4.2 Carbon Emissions

The model calculates the carbon emissions reductions for each alternative heat technology based on the business as usual alternative. The heat pump component of the DH solution and EHP and HHP options assume the BEIS projection for decarbonisation of the electricity grid (DECC, 2015).

The results are shown in Table 27 which indicates that the hydrogen conversion would deliver the greatest total lifecycle carbon emissions reduction. The hydrogen solution would also offer the lowest net present cost per tonne of CO_2 saved.

The CO_2 reduction for hydrogen is higher than other technology solutions due to the inclusion of CCS at the source of Hydrogen generation. This result is also likely to be influenced by the early adoption and 100% uptake of hydrogen by customers assumed in the model. Other technologies are phased over 15 years and therefore more carbon intensive while gas boilers remain.

The DH solution has a lower total carbon emissions reduction compared to the EHP and HHP scenarios and a higher total cost per tonne of CO_2 saved. It should be noted that the DH scenario included in the model includes an assumption of back-up gas boilers supporting biomass boilers and heat pumps. Alternative technology options for the DH option could have an impact on the lifecycle cost, carbon emissions reduction and cost of carbon abatement.

7.2 Sensitivity Analysis

A series of sensitivity analyses were undertaken in the model. These results are plotted and show the range of results for each of the technology options. The key sensitivities considered are:

- total CAPEX of main heat generation asset;
- total CAPEX of infrastructure asset; and
- fuel price

The methodology for performing the sensitivity analysis that was adopted is based on the variables and their respective range of variance in Table 29. This reflects to different levels of certainty associated with the cost assumptions.

Table 29: Sensitivity analysis variables and their respective range of variance

Sensitivity	Technology Option	Variable	Variance Range
Main heat generation asset	DH	Energy Centre	+/- 30%
Main heat generation asset	EHP	EHP Capital Cost	+/- 20%
Main heat generation asset	HHP	HHP Capital Cost	+/- 30%
Infrastructure asset	DH	DH Network	+/- 20%
Infrastructure asset	EHP, HHP	Electricity Grid Upgrade	+/- 30%
Infrastructure asset	H2	Gas Grid Upgrade	+/- 30%
Fuel price	H2	Levelised Cost of H_2	- 10% + 50%
Fuel price	All	Fuel Cost	+/- 20%

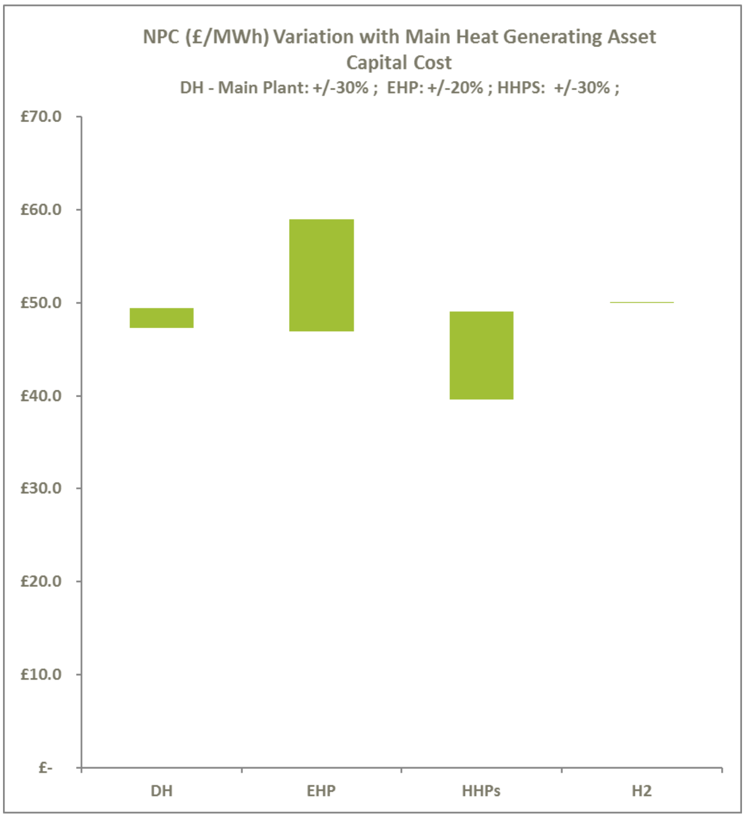


Figure 32 : Sensitivity analysis on the CAPEX of the main heat generating asset showing the range of NPC for the technology solutions in the main scenario

The range of results for the above variations in the respective main heat generation assets for the scenarios are illustrated in Figure 32. This shows that the NPC for the scenarios is influenced by the capital cost of heat production and that this effect is more pronounced for the EHP and HHP scenarios. There is no effect for hydrogen since the main scenario models the capital cost of hydrogen generation within the levelised cost of hydrogen supply. The net present cost is affected by the combination of generation, supply and customer interface costs. Table 27 shows that the share of cost for the heat generation asset for EHP and HHP options are more significant than for DH.

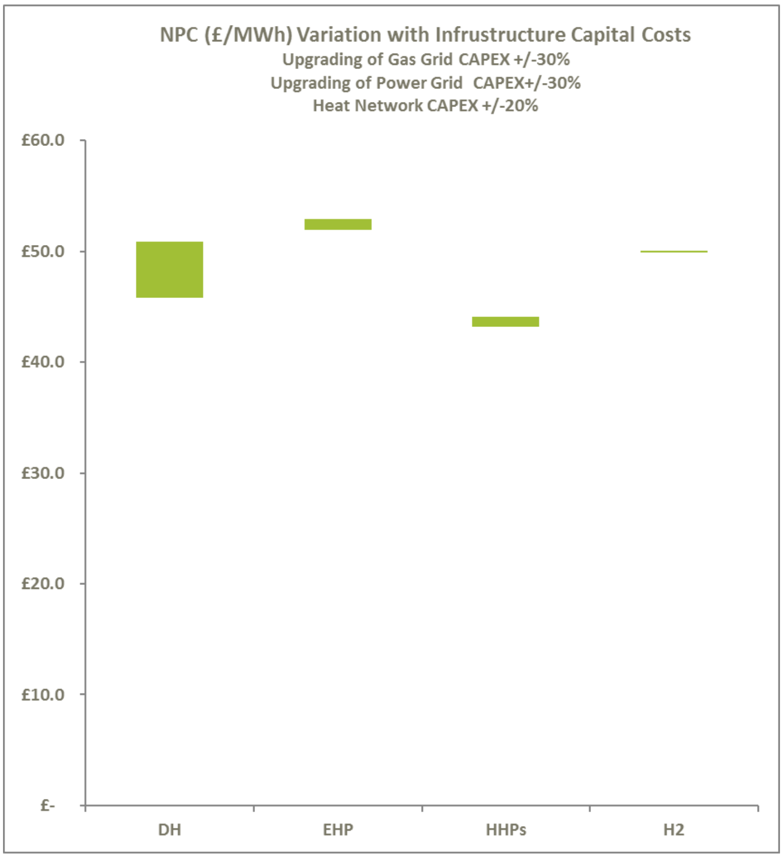


Figure 33 : Sensitivity analysis on the total infrastructure CAPEX showing the range of NPC for the technology solutions in the main scenario

A key uncertainty around many of the technology options is the cost of infrastructure investment necessary. The range of results for the variation in the respective capex cost of the infrastructure are illustrated in Figure 33. This shows that the NPC for the DH scenario is heavily influenced by the infrastructure CAPEX. Hydrogen, HHP and EHPs are less affected by this.

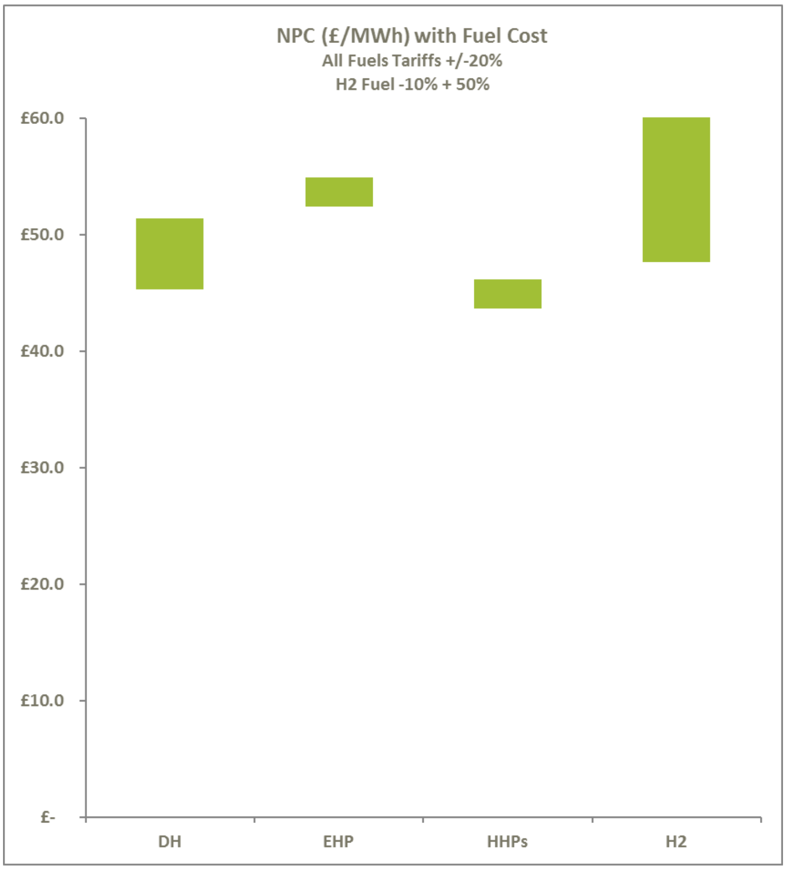


Figure 34 : Sensitivity analysis on the fuel cost showing the range of NPC for the technology solutions in the main scenario

The fuel cost associated with the technology options represents a large proportion of the lifecycle cost. The range of results for the variation in the respective fuel cost are illustrated in Figure 34. This shows that the NPC for the hydrogen scenario is most heavily influenced by the fuel cost. This fuel cost variation includes uncertainty associated with hydrogen generation from SMR, CCS, and hydrogen storage. DH is also significantly affected by fuel cost and more so than HHP and EHPs.

8. ALTERNATIVE MODELLED SCENARIOS

Two variations on the main scenario were considered to illustrate the impact of certain specific decisions on the levelised cost of deployment. It should be noted that these do not represent actual projects or policies. These variations were as follows:

- The impact of implementing specific energy efficiency improvements to individual properties on the lifecycle cost of the four technology options (this allows each technology option to operate at lower temperatures, generating further carbon emissions savings)
- A stand-alone pilot Hydrogen project in Cowdenbeath – i.e. where economies of scale from wider roll-out do not apply (CCS was not included in this scenario);

8.1 Effect of Conversion to Low Temperature

An additional variation on the main scenario was modelled to consider the effect of low temperature solutions. These results can be compared directly with the main scenario to illustrate the impact of the energy hierarchy and deployment of energy efficiency and replacement heating systems on the lifecycle cost of the scenarios. The detailed results of this analysis are included in Appendix D with key results included below.

	NPC (£/MWh)			
	H2	DH	EHP	HHPs
Primary Generation	£ 24.7	£ 20.6	£ 10.4	£ 9.9
Infrastructure	£ 2.6	£ 13.8	£ 2.1	£ 1.2
Customer Interface	£ 11.4	£ 13.6	£ 30.4	£ 28.6
Total NPC	£ 45.0	£ 44.0	£ 42.6	£ 39.4
CO2 Reduction over 39 years from now - (Tonnes)	1,608,156	1,303,290	1,487,961	1,398,996
NPC per tonne of CO2	£ 201.2	£ 242.4	£ 205.4	£ 202.1

Table 30 : Key economic and carbon indicators of performance of solutions based on low temperature options (including fabric energy efficiency in all properties)

The comparison with the results for the high temperature scenario (Table 27) show that there is a reduction in the NPC for all scenarios with the investment in energy efficiency and low temperature heating systems. The benefits come from a reduction in overall heat demand and consequential reduced cost of fuel as well as predicted improved efficiency of heat pumps and reduced heat losses in the district heating scenario.

The savings compared to the main scenario option are as follows:

- Hydrogen technology shows a 10% reduction on the NPC and 0% change in CO_2 reduction
- District Heating technology shows a 9% reduction on the NPC and 0% change in CO_2 reduction
- EHP technology shows a 19% reduction on the NPC and 1% greater CO_2 reduction
- HHP technology shows a 10% reduction on the NPC and 2% greater CO_2 reduction

These benefits in terms of lower NPC require a higher capital investment in fabric energy efficiency and property heating system upgrades this is further described in Appendix D.

8.2 Lifecycle Costs of a Pilot Hydrogen Network Deployment for Cowdenbeath

The pilot hydrogen deployment scenario varies from the main scenario due to the increased cost of hydrogen supply to account for the cost of CCS. The main costs associated with the deployment of a pilot project to deliver 100% hydrogen supply to Cowdenbeath are:

- Operational fuel costs for wholesale hydrogen purchase are assumed to be lower than main scenario due to the exclusion of carbon capture requirements; and
- The assumed cost of customer boiler replacements is approximately 54% higher under the pilot scenario due to the lack of market preparedness in manufacturing of individual boilers due to low market uptake (Table 16).

The net present lifecycle cost for the deployment of 100% hydrogen supply across all zones is estimated in the order of £42.9 /MWh. This represents a decrease of approximately 14% compared to the main scenario. Compared to the main scenario these costs exclude the addition of carbon capture and storage but an increased cost for the hydrogen boilers which brings the overall cost lower.

The results in terms of the total net present cost (NPC) for the hydrogen technology options considered is shown in Table 31.

Table 31 : Key economic and carbon indicators of performance of solutions in the pilot scenario for Hydrogen compared to the main scenario

	NPC for Hydrogen Solution (£/MWh)	
	Main Scenario	Pilot Scenario
Primary Generation	£ 30.5	£ 26.7
Infrastructure	£ 2.6	£ 2.6
Customer Interface	£ 11.5	£ 14.6
Total NPC	£ 49.9	£ 42.9
CO2 Reduction over 39 years from now - (Tonnes)	1,608,156	-628,239

The plant at Mossmorran operates a process that synthesises natural gas and produces hydrogen as a co-product. The plant is not assumed to include the capture, transport and storage of carbon emissions associated with hydrogen generation. This scenario therefore increases the carbon emissions relative to the business as usual. This comparison illustrates the need for this solution to be coupled with CCS to meet the UK and international objectives of carbon reduction.

Table 31 shows that the primary generation costs are lower for the pilot scenario due to the exclusion of CCS. The customer interface NPC is approximately 27% higher for the pilot hydrogen scenario due to the higher manufacture cost of boilers without national supply chain development.

9. CONCLUSIONS

The modelling of the main scenario, which models the projected costs of a project developed for Cowdenbeath as part of a national roll-out of technology solutions, indicates that the lowest net present cost (NPC) for the solutions modelled is offered by the hybrid heat pump solution. The remaining technologies are, in order of increasing NPC: district heating, hydrogen and electric heat pumps.

The Hydrogen solution offers the greatest CO_2 reduction potential of 87% compared to the BAU. The EHP, HHP and DH options offer similar, lower savings. The hydrogen scenario in this analysis assumes that the hydrogen is produced from steam methane reformation with CCS.

The Hydrogen solution offers the lowest NPC per tonne of CO_2 saved. This is followed by HHPs, EHPs and DH, which has the highest NPC per tonne of CO_2 saved.

Table 32 : Key economic and carbon indicators of performance of solutions in the main scenario

	NPC (£/MWh)			
	H2	DH	EHP	HHPs
Primary Generation	£ 30.5	£ 24.4	£ 13.3	£ 13.0
Infrastructure	£ 2.6	£ 13.7	£ 2.1	£ 1.3
Customer Interface	£ 11.5	£ 14.3	£ 37.5	£ 29.9
Total NPC	£ 49.9	£ 48.3	£ 52.4	£ 43.7
CO2 Reduction over 39 years from now - (Tonnes)	1,608,156	1,303,290	1,468,127	1,368,241
CO2 reduction from BAU (%)	87%	70%	79%	74%
NPC per tonne of CO2	£ 222.9	£ 266.3	£ 256.4	£ 229.1

The results illustrate that HHPs offer the lowest lifecycle cost and cost of carbon emissions reduction. This offers the most attractive economic solution but will still retain gas supply and, hence will not achieve carbon neutrality. The main challenges to implementing any of the solutions considered will relate to lack of public acceptance, investment funding and regulatory mechanisms to proactively drive the uptake of solutions.

The main scenario is also compared to alternative scenarios relating to a pilot project to prove distributed hydrogen in a local grid and a low temperature option. These models are compared in Figure 35 and discussed in the following Sections.

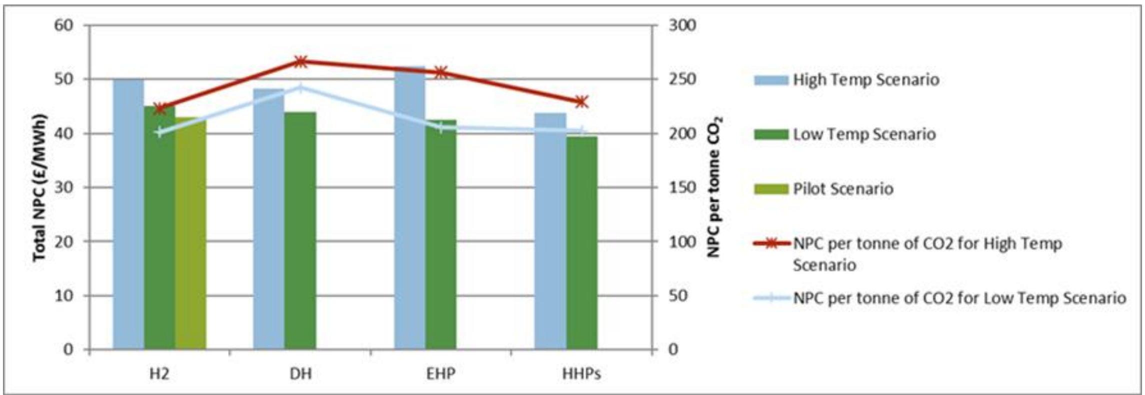


Figure 35: Comparison of NPC and cost of CO2 emissions reductions for technology options under different scenarios.

The comparison of the main scenario with the low temperature scenario indicates that the investment in fabric energy efficiency and low temperature systems results in a lower lifecycle cost. This is likely to be a result of the reduced energy consumption due to energy losses over the life of the project. .

9.1 Discussion of Results for the Main Scenario

The lowest net present cost (NPC) for the solutions modelled is offered by the hybrid heat pump solution. The technology solutions are not presented in the table in a merit order. The net present cost of the four technology solutions are all within 20% of the lowest so the results are highly sensitive to changes in assumptions.

When considering the analysis by looking at the town subdivided into zones and comparing against the heat density, then areas with larger building demands and higher linear heat density offer the lowest NPC under a district heating scenario. HHP performs best in low density areas. It is possible that a mix of solutions will be optimal.

Local natural resources and infrastructure will influence cost of heat production and therefore the least lifecycle cost solution may vary due to local circumstances. The report concludes that there is a requirement to standardise a methodology for strategic planning of energy solutions that reflects these differences.

The cost of financing the options will influence the relative affordability of each of them and may become one of the determining factors in preferred implementation strategy. Similarly, the differing delivery structures and approach to financing most suited to each of the scenarios may influence the degree of associated financial risk and therefore the willingness to invest in each of the options. For example, although there may be benefits in terms of the overall cost to society of implementing solutions with lowest whole life costs, these options may have higher up front capital costs and may therefore be more difficult to finance under a market based approach to delivery[36].

9.1.1 Sensitivity Analysis

For EHP and HHP the variation in CAPEX of the main heat generation plant is biggest influence on the NPC. For DH the variation in CAPEX of infrastructure has a large influence.

For DH and H2 the variation in fuel cost has a significant impact on the NPC compared to EHP/HHP.

Sensitivity analysis indicates the lifecycle costs of each solution are most sensitive to the capital costs of the primary technologies i.e. the upfront cost of the heat pump, hydrogen boiler and energy generation for district heating. The costs of the hydrogen solution in the main scenario are very sensitive to the wholesale cost of hydrogen, of which CCS will be a significant factor.

It is important to note that the technologies considered are at different stages of development and supply chain mobilisation. In particular hydrogen generation and CCS technologies are not as fully developed and proven as the other technologies. The results of the modelling are highly influenced by the information contained in a limited number of reports on cost regarding hydrogen and CCS. The variation in error margin for CCS and hydrogen is therefore considered to be greater. In addition the model assumes that

[36] If proposed as the mechanism for roll out of the scenario.

manufacturers will develop hydrogen boiler systems, EHP or HHPs and the resulting cost to consumers of these units will reduce with supply chain maturity and market competition.

The sensitivity of NPC to the cost of the main heat generation assets for the scenarios are illustrated in Figure 36. This shows that the NPC for the scenarios is influenced by the cost of the heat production unit and that this effect is more pronounced for the EHP and HHP scenarios since the cost of replacing the heat pump in individual properties is a greater share of the lifecycle cost than the alternative options. There is no effect for hydrogen since the main scenario models the capital cost of hydrogen generation within the levelised cost of hydrogen supply.

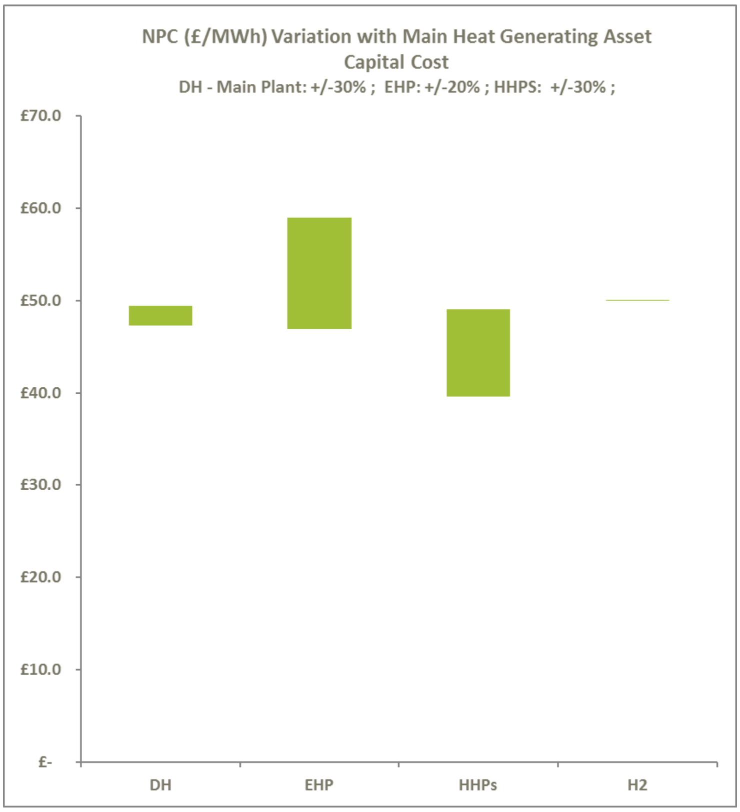


Figure 36 : NPC sensitivity to heat generation capital cost variability compared to the BAU

The scenarios are also sensitive to the cost of infrastructure investment necessary. The model shows that the NPC for the DH scenario is heavily influenced by the infrastructure CAPEX. Hydrogen, HHP and EHPs are less affected by this.

The fuel cost associated with the technology options represents a large proportion of the lifecycle cost. The model shows that the NPC for the hydrogen scenario is most heavily influenced by the fuel cost. This fuel cost variation includes uncertainty associated with hydrogen generation from SMR, CCS, and hydrogen storage. DH is also significantly affected by fuel cost and more so than HHP and EHPs.

9.2 Discussion of Results for the Low Temperature Scenario

The results of a modelled scenario considering the conversion of properties to a lower temperature heating systems shows that for all technologies there is a reduction in the NPC with the investment in energy efficiency and low temperature heating systems. The benefits come from a reduction in overall heat demand and consequential reduced cost of fuel as well as improved efficiency of heat pumps and reduced heat losses in the district heating scenario.

Under the low temperature scenario the EHP solution benefits significantly and offers a lower lifecycle NPC than DH and hydrogen. DH continues to offer lifecycle economic benefits compared to HHPs for the higher density zones under this scenario.

The Hydrogen solution offers the lowest NPC per tonne of CO_2 saved, however this is very closely matched to EHP and HHPs. DH has the highest NPC per tonne of CO_2 saved.

The model does not account for the disruption caused to consumers by investing in energy efficiency measures or how these solutions will be funded.

The low temperature scenario offers benefits in terms of lifecycle cost and cost of carbon reduction compared to the main scenario across all technologies. This is an interesting result and illustrates that appropriate investment in energy efficiency in buildings and conversion to low temperature offers long term benefits in terms of the economic cost of heat. The benefits come from a reduction in overall heat demand and consequential reduced cost of fuel as well as predicted improved efficiency of heat pumps and reduced heat losses in the district heating scenario.

9.3 Discussion of Results for the Pilot Scenario

The proximity of Cowdenbeath to Mossmorran offers a unique opportunity to undertake a large scale pilot to investigate the impact of hydrogen distribution within a town. The solution offers a benefit in terms of NPC compared to the main scenario. The solution is not low carbon but could be converted to low carbon after proving the concept through further investment in CCS or connecting the town to a national hydrogen network if this concept progresses.

9.4 Limitations and Recommendations for Further Research

The report presents a series of results and is supported by a lifecycle technical and economic model. There remain a number of key uncertainties in the assumptions which underpin the model and therefore further work is necessary in order to refine the analysis.

Sensitivity analysis was carried out on a number of key parameters, however the model allows for further research and study into the effect of varying uncertainty:

- Future fuel prices for all fuels, notably electricity and gas;
- Heat generation plant capital costs where limited commercial plants exist;
- Heat generation plant operation and maintenance costs including cost of hydrogen fuel;
- Future technology cost projections;
- Cost of district heating network; and
- Costs for conversion of boiler plant to heat interface units and conversion of appliances to electricity.

There would be benefit in utilising and testing the modelling approach by analysing other towns. Cowdenbeath is a medium sized town and considered typical of towns in the UK. Other towns will have different characteristics and the modelling approach could be applied to other locations and provide useful information for technology selection at the masterplanning stage.

The hydrogen assumptions – particularly CCS – are based on limited data for commercial CCS. Cost information needs to be developed to allow improved certainty of hydrogen technology.

The technology solutions will require development of regulatory and delivery frameworks. Regulatory models and commercial delivery models need to be developed for the deployment of these solutions.

The wider energy system is developing and developing heat solutions requires consideration of the integration of solutions within SMART Energy Systems. The solutions may impact on performance of the wider energy system when considered at a system level and these benefits should be further considered.

The timeline for roll out of preferred solutions needs to be considered in relation to regulatory, planning frameworks and development of the business case for local projects to build up into a national deployment. supply chain development also to be considered.

10. BIBLIOGRAPHY

AECOM. (2015). *Spon's Mechanical and Electrical Services Price Book.*

Arup. (2014). *London Heat Network Manual.* London: GLA.

Atlantic Boilers. (n.d.). Retrieved 10 14, 2015, from http://www.atlanticboilers.com/.

Barker-Brown, J. (2012, July 12). *http://www.yougen.co.uk/blog-entry/1954/An+introduction+to+water+source+heat+pumps+and+how+they+work/.* Retrieved 10 18, 2015, from http://www.yougen.co.uk/.

BIOS BIOENERGIESYSTEME GmbH. (n.d.). *http://www.bios-bioenergy.at/en/electricity-from-biomass/orc-process.html*. Retrieved 10 16, 2015, from http://www.bios-bioenergy.at.

Bios Bioenergiesysteme. (n.d.). *Description of the biomass CHP technology based on a steam turbine process*. Retrieved 10 16, 2015, from Bios Bioenergiesysteme: http://www.bios-bioenergy.at/en/electricity-from-biomass/steam-turbine.html

BSI. (2008). *Standardized method of life cycle costing for construction procurement. A supplement to BS ISO 15686-5. Buildings and constructed assets. Service life planning. Life cycle costing.* London: BSI.

CIBSE. (2014). *Biomass Heating: AM15.* London: CIBSE.

CIBSE. (2015). *Guide A - Environmental Design.* London: CIBSE.

CO2 Capture Project. (2016). *Annual Report 2015 - Collaborating to Build CCS Knowledge.* CCP.

Committee on Climate Change. (n.d.). *UK Emissions by Sector, Buildings*. Retrieved 2016, from Committee on Climate Change: https://www.theccc.org.uk/charts-data/ukemissions-by-sector/buildings/

DECC. (2011). *Renewable Heat Incentive.* London: DECC.

DECC. (2012). *The Future of Heating: A strategic framework for low carbon heat in the UK.* London.

DECC. (2015, March). Retrieved from Low Carbon Energy Report: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/419024/DECC_LowCarbonEnergyReport.pdf

DECC. (2015). *DECC Energy & Emissions Projections - November 2015 - Reference Scenario.* London: DECC.

DECC. (2015). *Historical gas data: gas production and consumption and fuel input 1920 to 2014.* London.

DECC. (2015). *Information for the Supply Chain on Green Deal Measures.* London.

Department of Energy & Climate Change. (2014). *Energy consumption in the UK.* DECC.

Dodds, P. a. (2013). Conversion of the UK gas system to transport hydrogen (Pages 7189–7200). *International Journal of Hydrogen Energy, 38*(http://dx.doi.org/10.1016/j.ijhydene.2013.03.070).

Emmeerson Climate Technologies / Vilter. (n.d.). *http://www.emersonclimate.com/europe/Documents/Brands/Vilter/Product%20Brochures/Brand_Vilter_Brochure_%20Heat%20Pump.pdf*. Retrieved 10 18, 2015, from http://www.emersonclimate.com/.

Energy Technologies Institute. (2015). *The role of hydrogen storage in a clean responsive power system.* Loughborough.

Enerzine. (n.d.). *http://www.enerzine.com/15/17824+recuperer-la-chaleur-residuelle-dun-four-a-arc-electrique-base-sur-lorc+.html*. Retrieved 10 16, 2015, from http://www.enerzine.com/.

ESP Ltd. (n.d.). *http://www.espprojects.com/esp-technoligies---combined-heat-and-power.html*. Retrieved 10 16, 2015, from http://www.espprojects.com.

EST. (2016). *Home Energy Check*. Retrieved from Energy Savings Trust: http://hec.est.org.uk/

GE. (n.d.). Retrieved 10 16, 2015, from https://www.ge-distributedpower.com.

GI Energy. (n.d.). *http://www.gienergy.net/technologies/ground-sourceheat-pumps*. Retrieved 10 16, 2015, from http://www.gienergy.net.

Greater London Authority. (2014). *London Heat Network Manual.* London.

H21 Leeds City Gate. (2016, July). *H21 Leeds Citygate Report*. Retrieved from http://www.northerngasnetworks.co.uk/wp-content/uploads/2016/07/H21-Report-Interactive-PDF-July-2016.pdf

HM Treasury. (2015). *Fixing the foundations: Creating a more prosperous nation.* London: Her Majesty's Stationery Office. Retrieved from https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/443898/Productivity_Plan_web.pdf

Industrial Heatpumps. (n.d.). *http://www.industrialheatpumps.nl/en/how_it_works/*. Retrieved 10 18, 2015, from http://www.industrialheatpumps.nl.

King, M. (2010). *Community Energy: Planning, Development and Delivery.* London: CHPA.

Kiwa Ltd. (2015). *Safety Issues Surrounding Hydrogen as an Energy Storage Vector.* DECC.

Lund University, Sweden; NeoEnergy Sweden Ltd. (n.d.). *http://www.gshp.org.uk/documents/4LinkingGSHPwithsolarthermalanddistrictheating.pdf*. Retrieved 10 17, 2015, from http://www.gshp.org.uk/.

Marywood University, Ohio. Department of Natural Resources. Aaron Harden, Tom Baker; Dispatch. (n.d.). *http://www.dispatch.com/content/stories/science/2011/08/28/dirty-past-clean-future.html*. Retrieved October 18, 2015, from http://www.dispatch.com.

Muller-Steinhagen, H. M. (2011, February 7). *Rankine Cycle*. Retrieved July 26, 2017, from Thermopedia: http://www.thermopedia.com/content/1072/

National Grid. (n.d.). *Understanding gas storage*. Retrieved 09 14, 2015, from National Grid: http://www2.nationalgrid.com/UK/Our-company/Gas/Gas-Storage/

National Statistics. (2013). *2011 Census Analysis - Comparing Rural and Urban Areas of England and Wales.* London: National Statistics.

Nexterra. (n.d.). *http://www.nexterra.ca/files/pdf/Project-Profile_UBC-20130321_FINAL_EMAIL.pdf*. Retrieved from Nexterra.ca.

Ramboll. (2016). *Alternative Heat Solutions for the UK User Guide.*

Ramboll. (2016). *Alternative Heat Solutions, Barriers and Risks.* DBEIS.

Scotia Gas Networks. (27-05-2015). Meeting with SGN.

Scottish Futures Trust. (2015). *Guidance on Delivery Structures for Heat Networks.*

Scottish Government. (2016, November 23). *Scotland Heat Map*. Retrieved June 2015, from Scottish Government: http://www.gov.scot/heatmap

Scottish Neighbourhood Statistics. (n.d.). *Area Profile*. Retrieved from Scottish Neighbourhood Statistics: http://www.sns.gov.uk/Reports/AreaProfile.aspx

SDH Solar District Heating.eu. (n.d.). *http://solar-district-heating.eu/Portals/0/Publicdownloads/S%C3%B8rensen-Dronninglund%20and%20Marstal-SmartDistrictHeating-updated-jen[1].pdf*. Retrieved October 18, 2015, from http://solar-district-heating.eu.

Slide Share. (n.d.). *http://www.slideshare.net/iewm/implementing-chp-district-heating-reducing-energy-costs-and-co2-emissions*. Retrieved 10 16, 2015, from http://www.slideshare.net.

Star Refrigeration Glasgow. (n.d.). *http://www.star-ref.co.uk/star/star-leads-the-way-with-world-s-largest-natural-heating-system.html*. Retrieved October 18, 2015, from http://www.star-ref.co.uk.

UK Government. (2008). *2008 Climate Change Act.* London: The Stationary Office Limited.

UK Government. (2015). *2010 to 2015 government policy: greenhouse gas emissions.* DECC, DEFA, EA.

Vent-Axia. (n.d.). *Vent Axia website*. Retrieved 09 28, 2015, from http://www.vent-axia.com/heatpump/how

Verdo Energy for the Future (Herz Boiler). (n.d.). *http://verdo.dk/en/bio/biofyr/erhverv/produktudvalg/paafyldning-og-lagerteknik/hydraulisk-paafyldningssystem*. Retrieved October 19, 2015

APPENDIX A
DETAILED DESCRIPTION OF DISTRICT HEATING TECHNOLOGIES

A.1. Biomass Boiler

A biomass boiler is purpose-designed to burn woody biomass fuels (hereafter referred to as solid biomass) and usually comprises a combustion chamber and heat exchanger to provide low or medium temperature hot water. A biomass system includes fuel storage, a fuel extract and feed mechanism, bespoke boiler controls and hydronic arrangements to protect the biomass boiler from low return temperatures, to store excess heat and to achieve efficient operation. Many biomass boiler systems include flue gas cleaning and all require a flue system. (CIBSE, 2014)

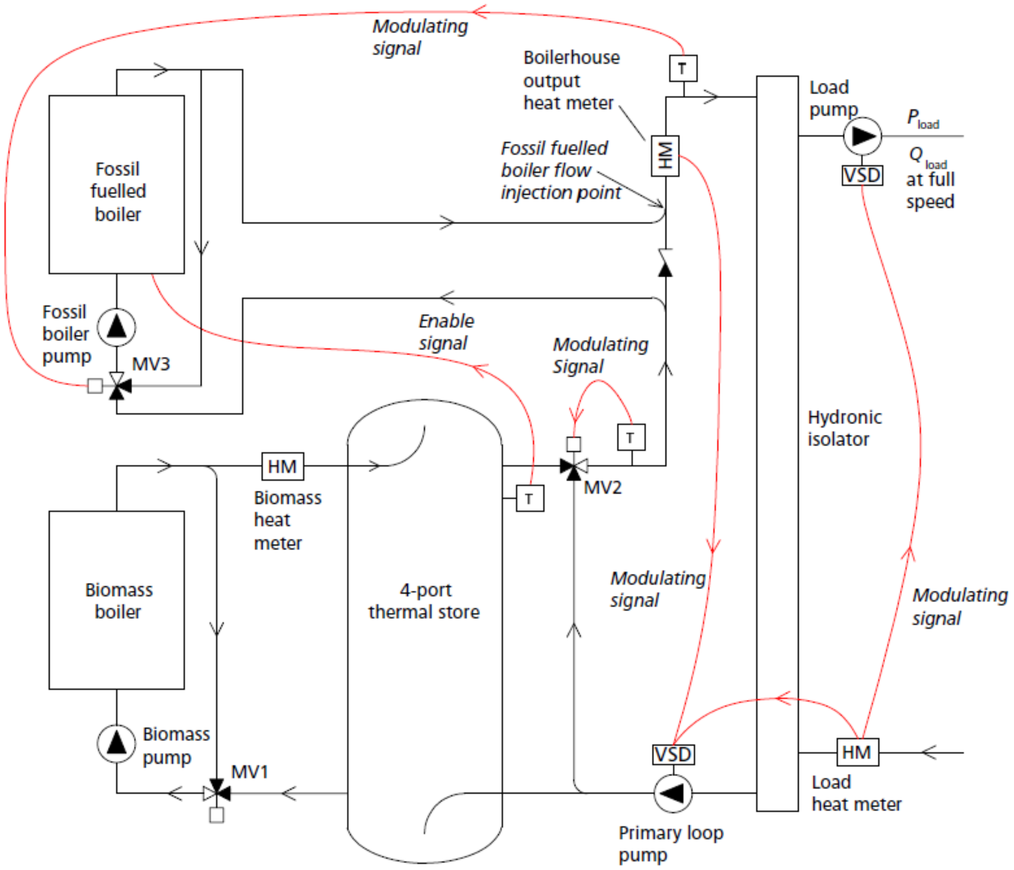


Figure 37 : Biomass Energy Generation in conjunction with Fossil fuelled boiler Schematic (CIBSE, 2014)

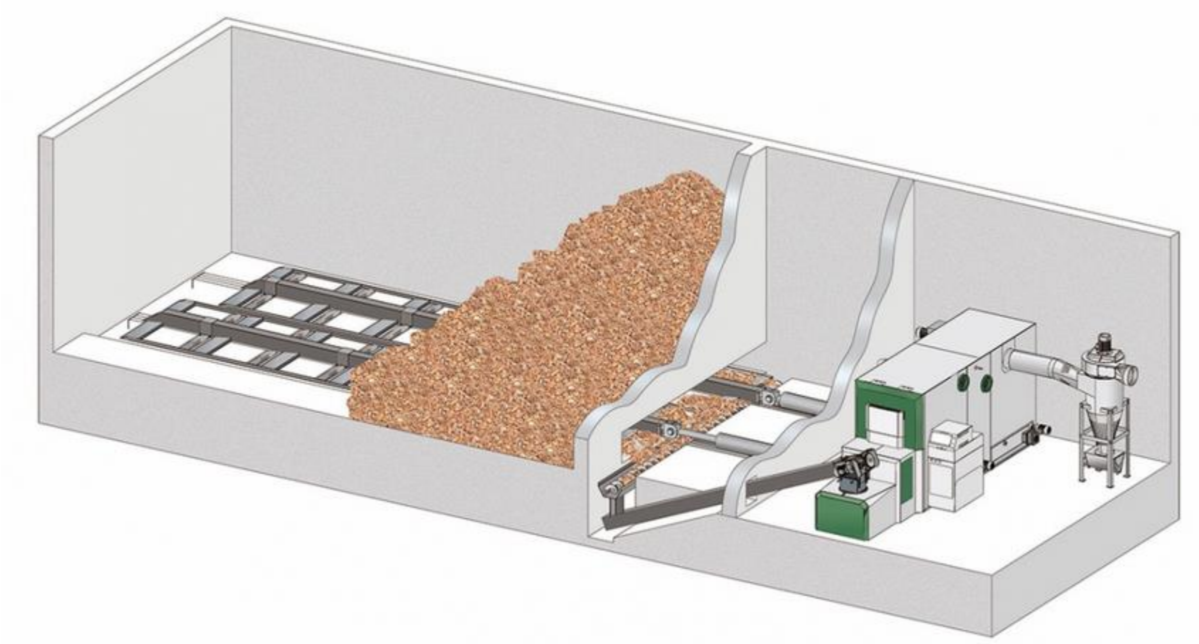


Figure 38 : Biomass installation complete with walking floor (Verdo Energy for the Future (Herz Boiler), n.d.)

Biomass Technology Energy Centre Assumptions:

- 7 days' woodchip stored (ie. each 7 days delivery needed unless an external larger woodchip storage is allowed)
- Woodchip storage shape and store-boiler woodchip handling mechanism are assumed to be silo with rotating arm on the bottom for energy centres ≤ 0.5 MWth.
- Woodchip storage shape and store-boiler woodchip handling mechanism are assumed to be walking floor for energy centres > 0.5 MWth.
- ≤ 30% woodchip moisture
- 80% default thermal efficiency

A.2. Heat Pump Technologies

A.2.1. Heat Pump Working Principle

A low temperature energy source can be upgraded to useful high temperature heat with the use of a heat pump. Among the different types of heat pumps that have been developed, the mechanical heat pump is the most widely used. Its operating principle is based on compression and expansion of a working fluid, or so called 'refrigerant'. A heat pump has four main components: evaporator, compressor, condenser and expansion device. The refrigerant is the working fluid that passes through all these components. In the evaporator heat is extracted from a waste heat source. In the condenser this heat is delivered to the consumer at a higher temperature level. Electric energy is required to drive the compressor and this energy is added to the heat that is available in the condenser. The efficiency of the heat pump is denoted by its COP (coefficient of performance), defined as the ratio of total heat delivered by the heat pump to the amount of electricity needed to drive the heat pump.

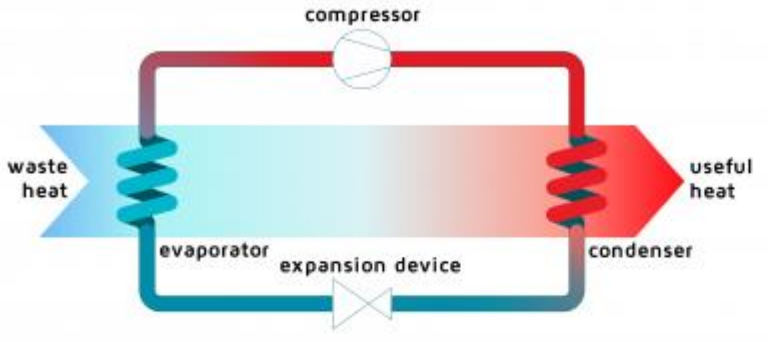


Figure 39 : Heat Pump operating principle (Industrial Heatpumps, n.d.)

A.2.2. Ammonia Heat Pumps (Low temperature heat sources)

For large scale industrial applications, Ammonia is the most suitable refrigerant for heat pumps that deliver heat up to a temperature of 90 °C.

In heating water to moderate temperatures, up to 71 °C, single stage ammonia heat pump systems provide optimal performance (COPs). In district heating however the desired water temperatures are higher than those provided by single stage systems and a two stage ammonia heat pump system is utilised. Higher differential water temperatures correlate to higher differential pressures in heat pump compressors. Therefore by splitting the heat pump design from a single stage to a two stage system, superior COPs are realized in achieving very high water temperatures, up to 90 °C.

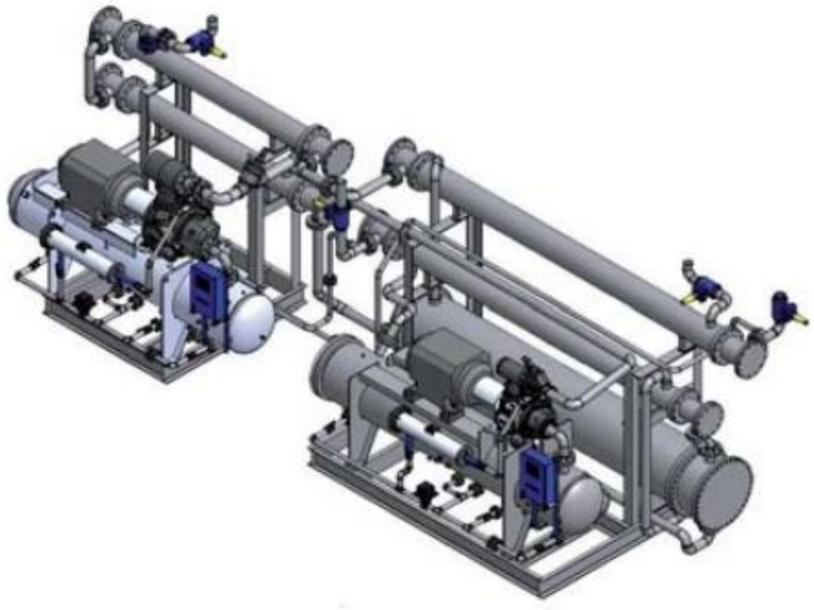


Figure 40 : Two stage heat pump illustration (Emmeerson Climate Technologies / Vilter, n.d.)

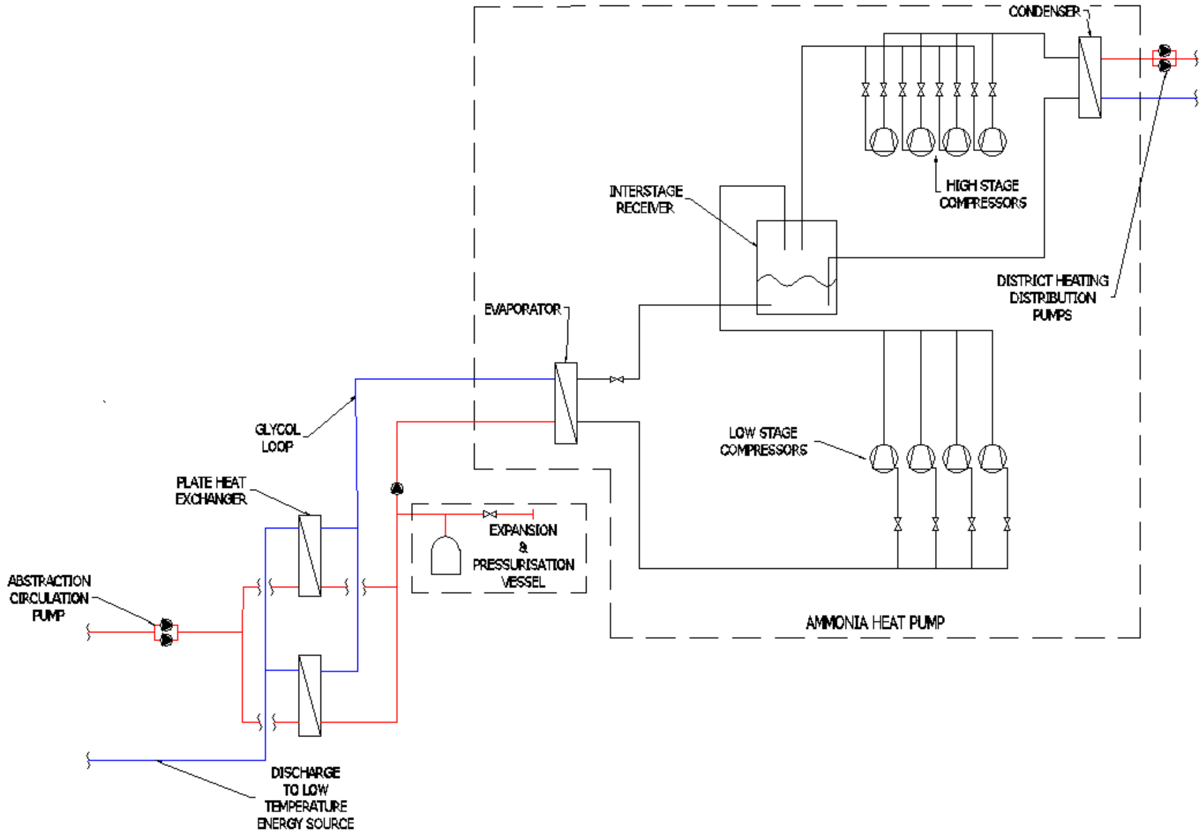


Figure 41 : Low temperature energy source extraction and upgrade via two stage ammonia heat pump

A.2.3. Ground Source Heat Pump

The ground beneath our feet absorbs almost 50% of all of the solar energy the earth receives from the sun. The earth is also very efficient at storing energy. It's because of this that the temperature just below the earth's surface remains at a consistent level all year round as it is constantly absorbing energy. Geothermal heating and cooling systems use this constant underground temperature to their advantage in order to provide heating and cooling to buildings.

A Ground Source Heat Pump (GSHP) uses the natural underground temperature of the earth in order to heat, cool and provide hot water to the network. They achieve this by recovering heat from the ground using underground pipes or by abstracting groundwater. Heat in the fluid is connected to a heat pump which issues heating or cooling into district heating or cooling networks.

Ground source heat pumps are an energy efficient and cost effective energy source as they do not burn any kind of fuel in order to produce their heat and use only the natural temperature of the earth as an energy generating method. (GI Energy, n.d.)

Figure 42 : Ground source heat pumps boreholes (Lund University, Sweden; NeoEnergy Sweden Ltd, n.d.)

Ground Source Heat Pump Energy Centre Assumptions

- Energy extracted via boreholes (close loop)
- 100 – 200 m deep boreholes
- Glycol working fluid to the ground (differs from Figure 7 above as Glycol will be directly delivered to the bore hole loop)
- Double stage ammonia heat pump/s

A.2.4. Water to Water Heat Pumps

A well-engineered water source heat pump system has access to a large volume of water; this enables it to extract heat from a very large heat source whose temperature will not change significantly as relatively small amounts of heat are extracted from it.

Using water as an energy source has a number of advantages when compared to air or ground source:

- The heat transfer rate from water can be higher than that in the ground or air.
- The flow/circulation of the water source provides constant energy replacement.
- The use of a water source removes the need of digging large trenches, often reducing the cost of installation compared to a ground source.
- The return temperature to the heat pump is usually higher than either the ground or winter average air, increasing the CoP (coefficient of performance) of the heat pump.

Water sources can be sea, lakes, ponds, rivers, springs or wells and the systems are usually classed as either 'open' where water is extracted from the source, flowed around the heat pumps intermediate heat exchanger (or an open loop rated internal heat exchanger) and then discharged; or 'closed' loop where, similar to a ground source, pipes or heat exchanger panels are placed within the water source and a water/antifreeze mixture is passed through the pipes/panels absorbing energy from the water.

Both systems have advantages and disadvantages. This study however considers the open loop option as being the most practical for district heating applications.

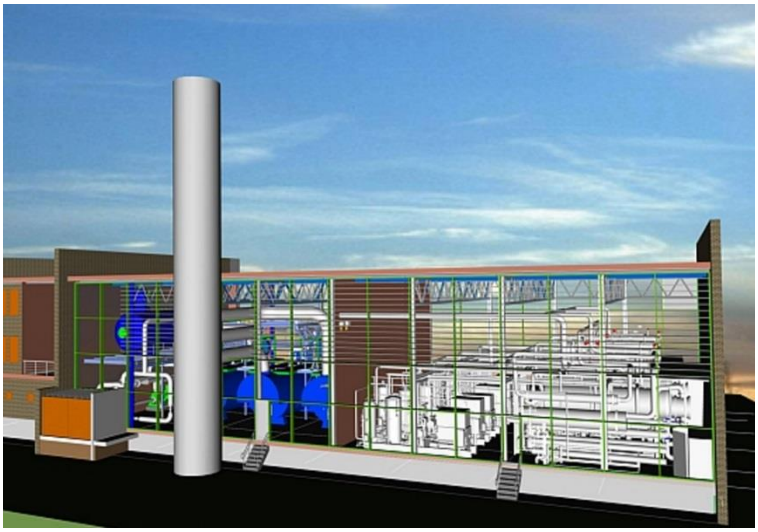


Figure 43 : Large district-wide natural heat pump system, providing 13 MW for Drammen, near Oslo, Norway. (Star Refrigeration Glasgow, n.d.)

Water Source Heat Pump Energy Centre Assumptions

- Open loop system
- Extraction license and discharge consent from the associated Environmental Agency is granted
- Water treatment and filter installation included (2 stage filtration with duty and stand-by pumps)
- Double stage ammonia heat pump/s

APPENDIX B
DESCRIPTION OF HYDROGEN TECHNOLOGIES

B.1. Hydrogen Supply

B.1.1. By-product hydrogen or External Supply

This is hydrogen supplied from an external supplier (potentially the national hydrogen grid) or produced as a by-product of industrial processes such as the ethylene plant at Mossmoran. The hydrogen produced is generally used as fuel to heat industrial processes. Consequently it can have impurities which are generally not an issue if the hydrogen is combusted on site but if it is to be used in the grid then these impurities should be removed since they could be corrosive or hazardous. Consequently, clean up processes will be required. Under this scenario the model applies a cost per MWh (£/MWh) of hydrogen supplied to the town at the boundary of the study area.

B.1.2. Steam Methane Reformation (SMR)

Steam methane reforming comprises two primary reactions: the reforming reaction and the water gas shift reaction. In the reforming reaction, natural gas is mixed with steam, heated to over 815 degrees Celsius, and reacted with nickel catalyst to produce hydrogen (H2) and carbon monoxide (CO). To produce additional hydrogen, CO from the reforming reaction interacts with steam in a second stage defined as the water gas shift. This reacts the CO with water (H2O) to produce carbon dioxide (CO2) and H2.

Generally SMRs are industrial processes but smaller packaged SMRs have been produced to provide hydrogen for relatively small scale installations. Under this scenario for hydrogen production it is necessary to include carbon capture and storage in order to meet the UK government targets for decarbonisation of heat. Carbon dioxide capture from smaller units is predicted to be more expensive per kilogram of hydrogen produced.

B.1.3. Electrolysis

Electrolysers use electricity to split water into hydrogen and oxygen. Electrolysers have developed considerably over the last few years using polymer electrolyte membrane (PEM) technology instead of the most common form; alkaline electrolysis. Hydrogen produced from electrolysis is generally very pure although the alkaline process does require trace oxygen removal from the hydrogen stream which is a relatively straightforward process.

B.1.4. Hydrogen Storage

There are 3 main ways of storing hydrogen which are liquefaction, compression or in a "hydrogen sponge" such as metal hydrides. Liquefaction is not considered a viable solution for this model due to the capital cost at this scale and the fact that boil-off occurs independently of demand. Compression at local scale can be achieved in cylinders, which is a long proven technology see B.1.5. Larger scale storages of hydrogen can be achieved in subterranean caverns. Metal hydrides are a developing technology which is now becoming technically and economically viable, both of which are considered as options for this model.

B.1.5. Underground Storage

The use of large scale underground storage is reported elsewhere (Energy Technologies Institute, 2015). This option is likely to be required if a national hydrogen grid is developed. The cost of underground storage, like that for dedicated production from SMR or electrolysers, is assumed within the cost of hydrogen in the model as these plants would be located outside the system boundary.

B.1.6. Compression

Mechanical compressors are used to compress hydrogen to pressures up to around 300 bar at which pressure the hydrogen is stored in readily available storage vessels. This is common for transport and storage of hydrogen today and can be transported in trailers.

Caverns are generally pressurised to 40-200bar pressure.

Further compression to 350 and 700 bar is common for the use of hydrogen in motive power fuel today.

B.1.7. Metal Hydride

There are a number of suppliers with slightly different methods of charging and discharging of hydrogen but generally hydrogen is stored in the hydride at ambient temperature and below 10 bar pressure. However to release the hydrogen the hydride needs to be heated to relatively high temperatures of 200 – 300 °C.

B.2. Hydrogen Infrastructure

The existing gas network has the potential to be converted to transport natural gas to hydrogen. Existing plastic pipes (medium density polyethylene and high density polyethylene) pipes are considered to be suitable for conveying hydrogen, whereas the metallic pipes are not expected to be suitable mainly due to the risk of hydrogen embrittlement of the pipe and the potential for leaks at joints. During the study Ramboll consulted with Scotia Gas Networks (SGN) who, like other gas distribution network operators, has an investment plan to replace metallic pipe to plastic infrastructure within the current regulated price control period (RIIO-GD1).

For the pilot study SGN provided GIS data on their gas distribution network in the town including details of the pipe diameter and the material comprising the existing infrastructure. The following information is required from the gas network operator to the study town:

- network layout provided as GIS shapefiles
- Associated information on pipe network condition/material
- Information on investment plan for the network to replace metallic with plastic pipe

The model makes an important assumption that PE pipes are suitable for conveying hydrogen and that the programme of conversion to PE pipes in the UK will be complete before any hydrogen network scenarios are enabled.

The existing high pressure, high strength steel transmission and distribution gas network is unsuitable for the transport of hydrogen gas due to its susceptibility to hydrogen embrittlement. One solution for delivering hydrogen to end-users would be via locally based hydrogen production and storage units located near the existing low pressure network injection points. This delivery strategy would alleviate the investment required to replace the existing high pressure natural gas steel transmission network but would require a CO_2 transport network to be built instead. As compressors are typically only used in the high pressure gas network, supplying the hydrogen directly into the low pressure network would also avoid the investment required to upgrade centrifugal compressors to handle the higher volumetric flow rate of hydrogen. It has been assumed for the purpose of this study that the low pressure distribution gas network is made of PE pipe.

The reuse of the existing gas network requires an assessment of the network capacity. This was completed as part of this study outside of the model in dedicated hydraulic modelling software. This is a limitation of the approach since any further studies would need to verify the gas network capacity. The network currently conveys natural gas to customers. Hydrogen has a lower energy density than natural gas so, unless demand reduces, the same energy supply will need to be maintained which will require higher gas flows and consequentially higher pressures and velocities. The capacity of the pipe network could therefore be constrained by pressure limitations.

Conversion of the UK gas system to transport hydrogen (Dodds, 2013) examined practical issues associated with transporting hydrogen in the natural gas network and concluded that hydrogen can be transported safely in low-pressure pipes. However, using hydrogen in the existing natural gas network will reduce the capacity and the linepack storage of the system as hydrogen has a smaller higher heating value (HHV) (approx. 13 MJ/m^3) than natural gas (approx. 40 MJ/m^3). The linepack capacity of the hydrogen gas network would be improved by operating the network at a higher operating pressure than the current low pressure natural gas network operating pressure. This operating pressure would be limited by the pressure rating of the pipe under consideration.

B.2.1. Hydrogen Physical Characteristics

The following physical characteristics for hydrogen were assumed when modelling the hydrogen gas network:

Physical Characteristics of hydrogen	
Relative Density	0.0696
Absolute Temperature (K)	293
Supercompressibility	1
Dynamic Viscosity (bar.s)	0.88 x 10^{-10}
Higher Heating Value (MJ/m^3)	12.7

Table 33: Physical Characteristics of hydrogen Gas Flow in Pipes

B.2.2. Modelling of the Gas Network to Convey hydrogen

Ramboll Energy's in-house thermal and hydraulic modelling software was used to model the gas networks and is suitable for use with compressible fluids. The pressure and flow within the pipe network is described by a formula from ASCE, Pipeline. Div. 1975. "Pipeline Design for hydrocarbon Gases and Liquids".
The formula is as follows:

$$Q = C.\frac{T_b}{P_b}.F.D_i^{25}.\sqrt{\frac{P_1^2 - P_2^2}{d_b.T_f.Z_m.L}}$$

The variables are as follows:

- Q: Flow in normal m^3/h
- C: Constant
- Tb: Reference temperature
- Pb: Reference pressure
- F: Frictional factor
- P1: Up stream pressure (bar a)
- P2: Downstream pressure (bar a)
- Di: Inner diameter for pipe
- Db: The density relative to dry air at reference pressure and temperature
- Tf: The temperature of the gas
- Zm: Super compressibility at mean pressure
- L: Length of pipe in km

The factor F is calculated from Colebrook-White's formula.
This formula shows that the flow rate of a gas in a pipe is governed by the pressure drop in the pipeline.

The network is modelled with hydrogen gas as the energy carrier and also with natural gas as the energy carrier. The resulting pressure drop on each pipe branch for the hydrogen network was compared with the corresponding results for the natural gas network.

APPENDIX C
ELECTRICITY NETWORK

C.1. Electricity Infrastructure

The following Appendix details the data analysis (and assumptions) that were applied to the assessment of the electricity network upgrade required for the EHP and HHP scenarios.

C.1.1. Demand Data

Demand data was derived from two sources, namely:

a) Annual demand profiles for all substations supplying the town; and
b) Peak demand forecasts for each substation supplying the town[37].

For (b) it is possible that the supplies to the town are not clearly defined (ie. from one individual substation) and therefore additional clarifications with Scottish Power are necessary to determine the actual load split.

C.1.2. Network Data

Appropriate network data was used to allow a reasonable assessment of the existing network in terms of its layout and its interconnection to other parts of the distribution network, other DNO licence areas and the transmission network. Scottish Power Distribution (SPD) use a Geographical Information System (GIS) based Utility Map Viewer (UMV) which provides a reasonably high level of granularity with respect to the distribution network.

C.1.2.1 Equipment data

Standard equipment schedules were used to assess any differences in equipment and network configuration methods employed from the base case model. It was critical to identify whether this has a positive or negative impact on the cost outcomes for network reinforcement.

C.1.2.2 Network assessment considerations

Once the demand profile has been developed and the network data has been reviewed an assessment is needed to ascertain how much of the ASHP demand can be supplied from the existing network (ie. with only minor LV reinforcement such as splitting of the network).

This assessment needs to consider the electrical infrastructure holistically, ie. from LV services up to transmission level if necessary. The questions that will therefore drive this assessment are:

c) Can the existing system supply all the demand through the LV system with only minor reinforcement[38]?
d) Can the existing system supply all of the demand through the 11 kV and LV networks with only minor reconfiguration?
e) What percentage of the peak demand can be absorbed into the existing system?
f) Can the HV network be split, and therefore will a new primary substation be required?
g) Is there sufficient capacity to connect a new primary sub-station (PSS) to an existing grid supply point (GSP)?
h) What will the estimated distance of the PSS from the GSP?
i) Does the transmission network need to be reinforced?

The outcomes from the above questions set the boundaries for calculating the appropriate cost of reinforcement according to the relevant network reinforcement factor.

C.1.2.3 Network reinforcement factor

The cost of reinforcement is based on a network reinforcement factor that is specific to SPD.

There are mechanisms that may be available to fund innovative low carbon pilot programs and further implementation. These schemes include:

---

[37] This can be obtained from the associated licenced DNO's Long Term Development Statement 2014-2019.

[38] The model does not account for the costs of electrical storage, demand side management etc

- the Network Innovation Allowance (NIA) – to fund smaller innovation Projects that will deliver benefits to Customers as part of a RIIO-Network Licensee's price control settlement;
- the Network Innovation Competition (NIC) – an annual competition to fund selected flagship innovative Projects that would deliver low carbon and environmental benefits to Customers; and
- the Innovation Roll-out Mechanism (IRM) – to fund the roll-out of proven innovations which will contribute to the development in GB of a low carbon energy sector or broader environmental benefits.

The Network Innovation Allowance (NIA) Percentage apportioned to each DNO is seen below (CRC 2H).

Licensee	NIA Percentage (%)
ENWL	0.7
NPgN	0.6
NPgY	0.6
LPN	0.5
SPN	0.5
EPN	0.5
SPD	0.5
SPMW	0.5
SSEH	0.5
SSES	0.5

Table 34: Network Innovation Allowance (NIA) percentage apportioned

The mechanism for the calculation of these factors is available via Ofgem. Whilst this factor would appear to have merit within the realms of this study, the mechanism of calculation would not correctly inform the discussion since these factors are allocated to a range of measures and not only to grid reinforcement.

The IRM funding stream (CRC-3D) has merit in this regard as it provides the realistic amount of funding available to innovative low carbon projects. It does not however disaggregate how the funding is divided. In this regard, a number or factor that disaggregates the load related reinforcement under the CRC3D funding initiative should be established. However, the numbers available within the public domain establish this.

CRC-3D Innovation Roll-out mechanism - Materiality threshold amount (£m, 2012/13 prices) is given in Table 35.

Licensee	Materiality Threshold Amount
ENWL	6.21
NPgN	4.49
NPgY	5.86
LPN	7.44
SPN	6.52
EPN	9.72
SPD	6.45
SPMW	6.65
SSEH	4.56
SSES	8.42

Table 35: Materiality threshold amount

It becomes apparent that whilst having merit the network innovation fund does not provide an appropriate resolution of data to define how reinforcement may be applied. For this reason it becomes more appropriate to take a global view of reinforcement funding.

The total allowed level of load related expenditure is provided in RIIO-ED1-CRC3G and is declared below in Table 36.

Licensee	Regulatory Year							
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ENWL	14.8	18.6	12.4	16.1	15.2	16.5	22.3	19.4
NPgN	18.9	16.1	13.1	12.1	14.8	11.8	6.3	5.8
NPgY	8.0	10.2	10.4	14.0	18.4	14.7	11.1	13.2
LPN	45.7	42.5	46.0	41.9	48.0	46.8	41.0	40.2
SPN	26.1	34.1	35.2	25.9	21.1	20.9	27.5	25.6
EPN	43.1	46.6	46.2	40.1	42.9	47.4	49.8	44.4
SPD	18.4	20.5	25.2	19.7	14.8	14.0	14.7	13.2
SPMW	28.0	23.7	19.8	15.6	14.3	23.0	23.8	18.0
SSEH	8.8	10.5	14.2	15.2	19.4	18.9	22.7	21.4
SSES	25.8	32.8	26.2	30.0	18.3	27.5	38.7	33.8
WMID	22.2	22.5	22.7	23.2	23.7	23.8	24.6	25.5
EMID	51.3	51.7	50.8	51.5	51.6	52.7	54.6	54.5
SWALES	3.7	3.7	3.8	4.2	4.2	4.3	4.0	4.1
SWEST	5.3	5.4	5.5	5.9	6.1	6.3	6.5	6.9

Table 36: Opening level of allowed load related expenditure (£m, in 2012/13 prices)

Table 36 provides a figure that defines how much money each DNO will have to spend on reinforcement. This would be appropriate if each DNO had exactly the same network topology, characteristics and size. Needless to say this is not the case.

In order to normalise this number compared to the overall expenditure that Ofgem has allocated to the DNO, the RIIO-ED1-CRC3G load related expenditure is compared with the ED1 Final determination revenue as seen below in Table 37. The result of this is effectively a reflection of the cost of reinforcing the network scaled to its size and complexity.

Licensee	Regulatory Year							
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ENWL	0.00813	0.01020	0.00679	0.00882	0.00831	0.00902	0.01220	0.01064
NPgN	0.01492	0.01274	0.01035	0.00953	0.01168	0.00929	0.00500	0.00455
NPgY	0.00474	0.00602	0.00613	0.00829	0.01084	0.00867	0.00657	0.00780
LPN	0.02582	0.02400	0.02597	0.02365	0.02710	0.02640	0.02316	0.02272
SPN	0.01516	0.01981	0.02044	0.01502	0.01225	0.01211	0.01599	0.01488
EPN	0.01700	0.01838	0.01821	0.01581	0.01691	0.01870	0.01965	0.01749
SPD	0.01213	0.01350	0.01662	0.01299	0.00973	0.00918	0.00969	0.00868
SPMW	0.01682	0.01419	0.01188	0.00936	0.00857	0.01377	0.01425	0.01079
SSEH	0.00782	0.00938	0.01267	0.01358	0.01729	0.01685	0.02024	0.01906
SSES	0.01107	0.01406	0.01124	0.01283	0.00783	0.01177	0.01660	0.01449
WMID	0.05754	0.05832	0.05884	0.06014	0.06143	0.06169	0.06376	0.06610
EMID	0.13290	0.13394	0.13161	0.13342	0.13368	0.13653	0.14145	0.14119
Swales	0.01862	0.01862	0.01912	0.02114	0.02114	0.02164	0.02013	0.02063
Swest	0.01847	0.01882	0.01917	0.02057	0.02126	0.02196	0.02266	0.02405

Table 37: Load related expenditure with the ED1 Final determination revenue

The methodology now has varying multipliers but no effective benchmark. Considering Cowdenbeath as our point of reference, Scottish Power Distribution is responsible for the network in and around Cowdenbeath. Thus this is effectively a multiplier of 1, which every other DNO is compared against. If the generic cost to reinforce is higher, then the multiplier is above 1, if cheaper, the multiplier is less than 1. The result is a mapped set of multipliers that track DNO regulated reinforcement investment against Cowdenbeath (and SPD).

The result of this is seen below in Table 38.

Licensee	Regulatory Year							
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ENWL	0.67	0.76	0.41	0.68	0.85	0.98	1.26	1.22
NPgN	1.23	0.94	0.62	0.73	1.20	1.01	0.52	0.52
NPgY	0.39	0.45	0.37	0.64	1.11	0.94	0.68	0.90
LPN	2.13	1.78	1.56	1.82	2.79	2.88	2.39	2.62
SPN	1.25	1.47	1.23	1.16	1.26	1.32	1.65	1.71
EPN	1.40	1.36	1.10	1.22	1.74	2.04	2.03	2.01
SPD	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
SPMW	1.39	1.05	0.72	0.72	0.88	1.50	1.47	1.24
SSEH	0.65	0.70	0.76	1.05	1.78	1.83	2.09	2.20
SSES	0.91	1.04	0.68	0.99	0.80	1.28	1.71	1.67
WMID	4.75	4.32	3.54	4.63	6.31	6.72	6.58	7.61
EMID	10.96	9.92	7.92	10.27	13.74	14.87	14.60	16.26
Swales	1.54	1.38	1.15	1.63	2.17	2.36	2.08	2.38
Swest	1.52	1.39	1.15	1.58	2.19	2.39	2.34	2.77

Table 38: DNO regulated reinforcement investment as tracked against Cowdenbeath (and SPD)

APPENDIX D
MODEL OUTPUTS FOR LOW TEMPERATURE FUTURE SCENARIO

D.1. Modelling Results

The future scenario was modelled including the assumption that there is 100% uptake of energy efficiency measures and heating system upgrades to allow low temperature systems to prevail. The results of this model for all technologies are shown below.

	NPC (£/MWh)			
	H2	DH	EHP	HHPs
Primary Generation	£ 24.7	£ 20.6	£ 10.4	£ 9.9
Infrastructure	£ 2.6	£ 13.8	£ 2.1	£ 1.2
Customer Interface	£ 11.4	£ 13.6	£ 30.4	£ 28.6
Total NPC	£ 45.0	£ 44.0	£ 42.6	£ 39.4
CO2 Reduction over 39 years from now - (Tonnes)	1,608,156	1,303,290	1,487,961	1,398,996
NPC per tonne of CO2	£ 201.2	£ 242.4	£ 205.4	£ 202.1

Table 39 : Breakdown of cost for each of the technology options considered

The results of this scenario indicates that the hybrid heat pump solution performs best for all individual zones in addition to offering the lowest NPC for the town as a whole.

The cashflow curves for each of the solutions show similar profile to the main scenario. These curves are compared in Figure 44 and illustrate that there are high initial costs for the hydrogen and DH scenarios. The upfront costs of infrastructure for the heat pump scenarios low as they follow the lifecycle boiler replacements.

All costs increase in the short term compared to the main scenario due to the cost of conversion of property heating systems and investment in energy efficiency measures.

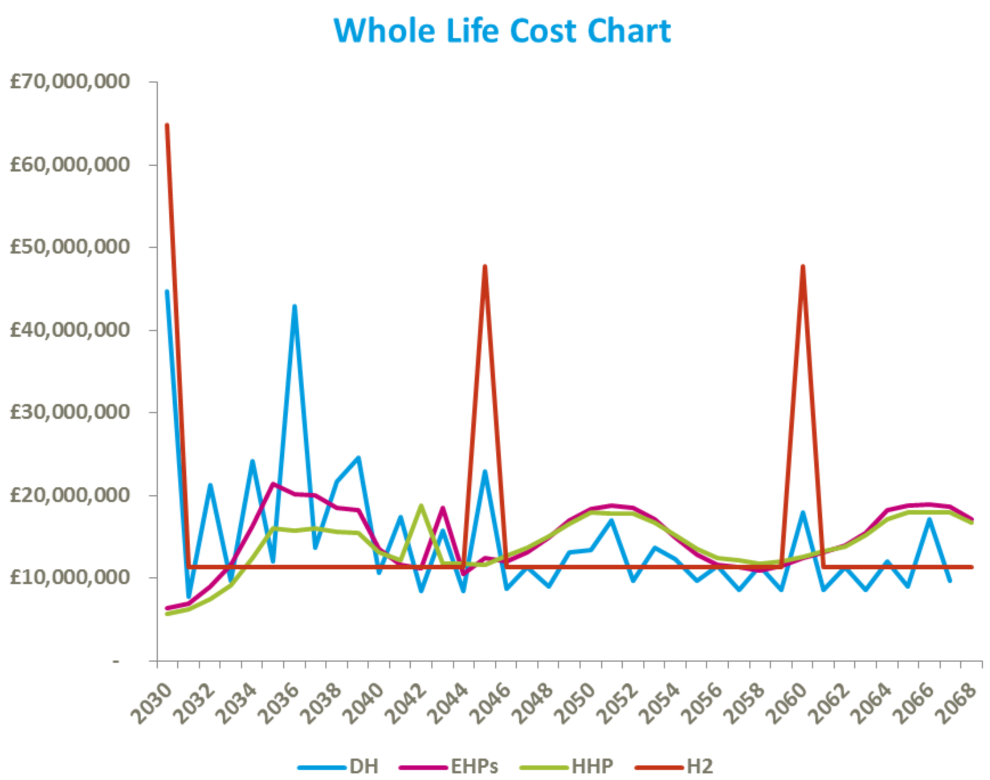


Figure 44 : Lifecycle cost graphs for comparison between each of the technology solutions

D.1.1. Comparison by Zone

The results of the model have also been compared and analysed across the twenty-five zones identified in Cowdenbeath. This analysis is simplified and is based on sharing the costs of generation and infrastructure according to the proportion of heat demand in the zone to the total town demand. The customer interface cost is shared across zones according to the proportion of customers within each zone compared to the total number of customers. The results in terms of NPC are shown in Table 40.

Table 40 : Comparison by zone of the net present cost per MWh of heat demand

Zone	Description	NPC[39] / MWh heat supplied (£/MWh)				LHD[40] (MWh/m)	AHD[41] (MWh/Ha)
		H2	DH	EHPs	HHPs		
Zone 1	Cowdenbeath High Street - Commercial/ Residential & Large Morrisons Supermarket	£45.7	£42.7	£44.8	£40.3	3.2	298
Zone 2	Thistle Street Industrial Estate - Light Industry	£39.8	£36.8	£52.5	£42.3	9.0	260
Zone 3	Bridge Street Residential - Council Semi-Detached, 2-up 2-down, & Cowdenbeath Primary School	£46.7	£44.8	£42.8	£40.0	3.3	397
Zone 4	Residential mixture - older/newer bungalows & St. Brides RC Primary School	£46.3	£48.6	£41.2	£39.1	2.3	301
Zone 5	Broad Street Residential - local authority semi-detached - 2 up, 2 down	£49.3	£46.2	£44.2	£41.0	3.8	375
Zone 6	Woodend Industrial Estate - Medium Industrial	£39.5	£41.2	£47.1	£37.0	5.4	163
Zone 7	Hill of Beath - Residential Terraced, Light Industrial, & Hill of Beath Primary School	£46.1	£47.5	£42.2	£39.0	2.4	163
Zone 8	Residential - Terraced & Council semi-detached	£46.2	£43.5	£40.3	£38.5	2.5	391
Zone 9	Gateside Industrial Estate - Food manufacturer & Light Industry	£36.4	£37.2	£46.6	£41.5	7.7	187
Zone 10	Stenhouse Road Residential - Mix of old & new semi-detached properties & bungalows with green space	£48.1	£53.2	£42.5	£39.9	2.3	272
Zone 11	Residential - Council owned semi-detached & local Police Station	£44.3	£47.0	£41.3	£38.7	3.3	314
Zone 12	Cowdenbeath Football Stadium & Leisure Centre	£35.2	£33.0	£37.0	£35.7	9.0	611
Zone 13	Beath High School & Residential - Mix of semi-detached and terraced	£44.4	£42.1	£42.7	£40.5	3.2	277
Zone 14	Foulford Residential - Mix of terraced and detached housing & Foulford Primary School	£45.7	£52.2	£41.2	£39.1	2.0	233
Zone 15	New Residential - Modern detached housing and new developments	£44.9	£43.5	£40.6	£38.6	2.5	243
Zone 16	Glenfield Industrial Estate - Light Industrial	£43.7	£52.8	£43.8	£38.5	2.5	198
Zone 17	Residential & light commercial – Semi-detached housing & Lumphinnans Primary Community School	£49.1	£52.7	£43.4	£40.5	2.4	239
Zone 18	Residential & light commercial - Semidetached housing & small number of flats	£47.0	£44.1	£41.9	£39.6	3.9	338
Zone 19	Residential - Council semidetached housing, small no. of flats, Lochgelly West & North Primary Schools	£49.3	£47.2	£44.7	£41.0	2.6	323
Zone 20	Residential Mixed - Modern detached housing & new developments	£44.0	£45.5	£38.7	£37.4	2.6	216
Zone 21	Lochgelly South - Residential Semi-detached housing & Lochgelly South Primary School	£46.8	£45.3	£41.7	£39.2	3.3	396
Zone 22	Lochgelly High Street - Commercial & small number of flats about high street shops	£43.6	£39.5	£43.1	£39.8	4.5	616
Zone 23	Lochgelly East - Modern detached residential and some light industrial	£43.8	£41.5	£40.6	£38.2	3.2	190
Zone 24	Lochgelly North - Residential mixture of semi-detached & bungalow	£45.0	£42.1	£41.7	£38.2	3.4	167
Zone 25	Cartmore Industrial Estate - Light Industrial & Lochgelly High School	£36.2	£33.7	£45.6	£39.0	6.1	170

[39] NPC presented at 3.5% discount rate

[40] LHD is the linear heat density and is represented by the overall annual heat demand per m of installed district heating pipe trench length (units are MWh/m). LHD is a useful indicator of the economic performance of district heating networks.

[41] AHD is the area heat density in units of MWh/m²

Zone	Description	NPC[39] / MWh heat supplied (£/MWh)				LHD[40] (MWh/ m)	AHD[41] (MWh/ Ha)
		H2	DH	EHPs	HHPs		
Town Wide		£45	£44	£43	£39		

It should be noted that there are various uncertainties, risks and sensitivity in the cost data and so the figures presented by zone should be treated as indicative of performance rather than absolute.

D.1.2. Carbon Emissions

The model calculates the carbon emissions reductions for each alternative heat scenario based on the business as usual alternative. The results are shown in Table 39 which indicates that the hybrid heat pump would deliver the greatest total lifecycle carbon emissions reduction. The hydrogen technology would offer the lowest net present cost per tonne of CO_2 saved. The HHP and EHP these options assume the BEIS projection for decarbonisation of the electricity grid.

The hydrogen scenario in this analysis assumes production from SMR with CCS. This scenario suggests that it can achieve good carbon emissions reduction and a resulting similar cost per tonne of carbon saved compared to EHP and HHP.

The district heating has a lower total carbon emissions reduction compared to the hybrid heat pump scenario and a higher total cost per tonne of CO_2 saved.