

Feasibility Study Minewater District Heat Network Horden



May 2023

**Completed by: Faye Tomson, Tom Lovegrove, Olivia Allen and
Duligong Honid**

Executive Summary

Introduction

This feasibility study was commissioned following completion of a micro-feasibility study for a community-based greenhouse at Horden, completed by District Eating in 2021. The initial piece of work concluded that there was potential to abstract heat from the minewater treatment scheme, and that it could be utilised for heating a greenhouse. This follow on work was commissioned by Durham County Council, to complete feasibility for a wider heat network, to heat buildings as well as a horticultural load. As the work was funded by HNDU, the specification of the project follows HNDU guidelines, and the CIBSE Heat Networks Code of Practice, referred to in the industry as CP1.

Stakeholder Engagement

Initially the District Eating (DEL) team identified all buildings of size and significance in the Horden area, and contacted them, sending out information on what a heat network is, and a questionnaire asking for interested parties to express interest, and answer some basic questions as to their annual heat demand, and existing heating systems. The response was excellent. At the same time the DEL team used rule of thumb guidance to estimate the heat demand of all other buildings of note, and engaged with Believe Housing, operators of DCC housing stock, to estimate the heat demand of social housing in Durham. As a result of this heat demand mapping and stakeholder engagement work, a full heat map was created, and two key clusters were identified for development-the Northern and Southern Clusters. The DEL team visited the site and conducted plant room surveys for key buildings.

Horticultural/Aquacultural Heat Demand

A week prior to the site visits, the team at DEL and DCC were contacted by a company looking to farm shrimps. Their plan was at the early stages, however it attracted attention, given the team had been made aware of the potential for damage associated with anti-social behaviour that is prevalent in Horden at the time of writing. A greenhouse is an expensive building that could easily be damaged, and it was agreed with DCC that a shrimp farm or other aquacultural development would be less likely to incur damage, as well as that, a potential developer was now interested. The shrimp farming company, Bluewater Shrimp gave an initial estimate of heat demand as being 500kW baseload, and it was agreed that given the relatively small size of the available heat supply, that assuming 500kW as a baseload for either a greenhouse or other yet to be defined aquacultural load was a sensible assumption to make.

As there is the risk that a greenhouse operator/shrimp farm operator might not come forwards, DE agreed to model a scenario that comprised of the Northern and Southern clusters only, at a high level, in addition to the main scenario.

Heat Supply

The heat supply assessment was carried out by Townrock Energy, subcontractors to District Eating (DEL). Townrock completed a detailed assessment of the minewater resource and concluded that there could be 1.34MW of heat available for the minewater. As the heat demand typically is lower at night, a heat battery, known as a thermal store can be used to

store water generated at times of low demand, which can then be discharged at times of high demand, effectively increasing the potential peak output by an additional XkW.

The DEL engineering team carried out a detailed heat pump sizing exercise based on a heat network heating the Southern Housing Cluster and an assumed horticultural or aquacultural installation, with an assumed baseload of 500kW, and a peak demand of 1,500kW. The engineering assessment was iterative, and included optimisation of pipe size and spec, temperature profile across the network and buildings. The full Townrock Energy report is supplied in conjunction with this report, as a standalone piece of work.

Financial Modelling

Heat demand and supply calculations then formed the basis of a financial modelling exercise. Unsurprisingly, given the rise in energy prices over the winter of 2022/23, the financial viability of a heat pump system is questionable, and if grid electricity prices are used as a basis for the business case, then the project is not viable at all. Thankfully there are other options. Power Purchase Agreements (PPA's) are a way of purchasing renewable electricity at lower prices. This work has modelled both options. The financials are challenging, and the project hinges on securing a low-cost power supply that can affordably power the heat pump.

Counterfactual, and Heat Price

BEIS, Now DESNEZ, require all heat network feasibility studies to consider a heat network project against heat they call a counterfactual. This is what would happen is a heat network wasn't constructed. New gas boilers will be banned from new buildings by 2026, and so the counterfactual for domestic buildings is assumed to be. Air source heat pumps. The counterfactual cost includes installation, maintenance, and replacement costs for an ASHP system over a 40-year lifespan. For commercial buildings, the counterfactual is assumed to be gas boilers, and again, the capital, maintenance and replacement costs are included in this.

The heat price assumed for the heat network consists of all the fixed costs associated with building and operating a heat network and connecting buildings up to the point of the heat meter and heat interface unit (HIU). The heat price also includes the cost of replacing components of the network and energy centre, and maintenance over a 40-year period. The initial capital outlay and ongoing electricity costs for running the minewater heat pump make up the majority of the costs.

Electricity prices have been modelled in 4 ways:

- BEIS forward price projections: \
 - domestic 40 year average 20.6p/kWh.
 - Commercial 40 year average 13.28p/kWh.
- PPA pricing¹ :7.08p/kWh.

¹ <https://app.pexapark.com/api/ppa-times/31/document>

- LCOE wind energy².
 - Onshore wind: 5.29p/kWh
 - Large scale solar: 5.06p/kWh

**The BEIS electricity price has been modelled to vary with DESNEZ forward price projections. The electricity price stated above are averages over the project lifetime of 40 years.*

Results

The tables below show the key financial metrics for the preferred scenario, scenario 1.

Scenario 1 has not been found to be economically viable when compared to a gas boiler counterfactual, even with a PPA agreement and is only just economically viable when all electricity is supplied by a wind turbine at the LCOE.

Gas boiler counterfactual	Scenario 1 with BEIS		Scenario 1 with PPA		Scenario 1 with onshore wind at LCOE	
	Solid Energy	Carrier	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	7.32	5.81	7.32	5.81	7.33	5.81
NPV at 40 years (£m)	-5.25	-6.09	-1.67	-1.39	-0.55	0.08
IRR at 40 years (%)	-6.59%	NA	-1.35%	-1.48%	-0.41%	0.08%
Discounted payback period	0	0	0.00	0.00	0	39.42

Gas boiler will however, at some point be banned, potentially as early as 2033. The economic impact of when this ban occurs has not been modelled. The table below however, shows the economic results of the project if heat is charged according to 95% of the ASHP counterfactual heat price. Scenario 1 now becomes economically viable even when supplied with electricity from the grid. This indicates that under certain economic conditions, a district heating network would likely be the most economical low carbon technology.

ASHP counterfactual	Scenario 1 with BEIS		Scenario 1 with PPA		Scenario 1 with onshore wind at LCOE	
	Solid Energy	Carrier	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	7.32	5.81	7.32	5.81	7.32	5.81
NPV at 40 years (£m)	1.86	1.02	5.44	5.72	6.57	7.19
IRR at 40 years (%)	1.40%	1.08%	3.50%	4.66%	4.1%	5.6%
Discounted payback period	30.71	32.67	21.37	18.05	19.55	15.88

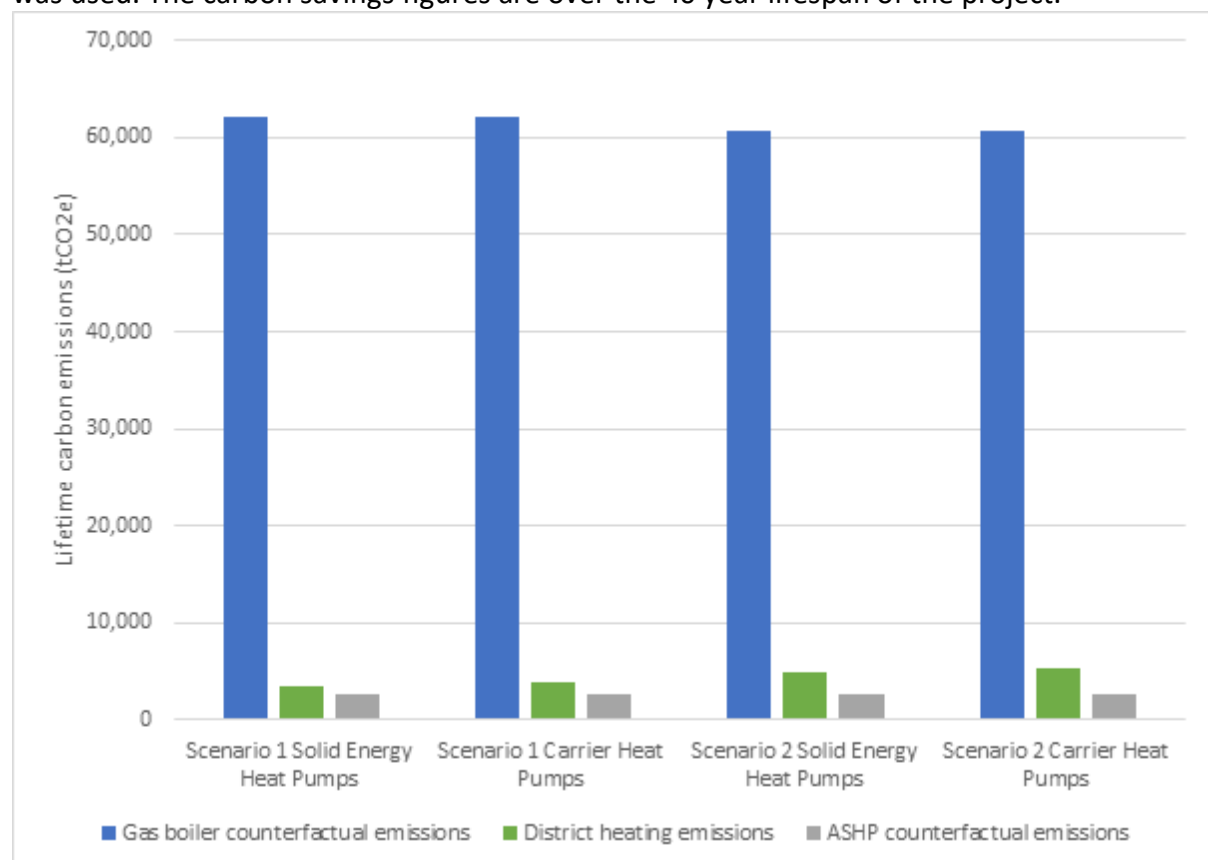
Scenario 1 is only economically viable when compared to a ASHP counterfactual for domestic buildings, and Council properties, with gas boiler counterfactual being assumed for commercial buildings. Reasonable IRR's are indicated if all electricity is supplied by a wind turbine at the Levellised Cost Of Energy (that takes into account capital cost, ongoing maintenance and replacement costs over the lifetime of the turbine). Positive IRR's are indicated also with a PPA arrangement. See full report for assumptions used in modelling.

It should be noted that for heat network projects, they are broadly regarded as investible if they could achieve IRR's in a range of 3%+ before capital funding. This said, the level at which a project is deemed investible varies depending on Council, and investor. It is up to DCC and funders to clarify their thoughts on this.

The scenario with Northern Cluster

Carbon Savings

The carbon emissions of the 2 scenarios along with their gas boiler and ASHP counterfactuals is shown in the graph below. From this it is clear that a district heating project would significantly reduce the carbon emissions of all buildings connected to the project. The preferred scenario of scenario 1 would reduce emissions by 58,705 tonnes of CO₂e if a Solid Energy heat pump was used and 58,230 Tonnes CO₂e if a Carrier heat pump was used. The carbon savings figures are over the 40 year lifespan of the project.



One of the reasons that these projects are developed is to save CO₂ compared to a business-as-usual scenario. The table below indicated the potential carbon savings that could be achieved for Scenario 1. Due to the use of a top up gas boiler in the energy centre,

decentralised individual ASHP on each building would, achieve more carbon savings but would be significantly more difficult to implement as well as being less economically viable.

Scenario	DHN lifetime emissions savings against gas boiler counterfactual (tCO ₂ e)	DHN lifetime emissions savings against ASHP counterfactual (tCO ₂ e)
Scenario 1 Solid Energy Heat Pumps	58,704	-702
Scenario 1 Carrier Heat Pumps	58,229	-1,177

Conclusions

- The economics of this project are challenging, though not insurmountable, provided DCC look to develop onsite renewable electricity generation or, seek to sign up to a competitive PPA agreement with a renewable electricity supplier.
- The work relies on the best estimates in terms of heat availability and heat pricing as provided by the Coal Authority. They are currently developing their process around heat abstraction and sale, and these metrics could change and develop in time, and probably will.
- This project uses very broad assumptions for the horticultural and aquacultural heat load. If DCC wish to pursue either horticulture or aquaculture at the site, then a separate piece of work will be required to do this.
- There is the opportunity to develop a standard heat network that incorporates the Northern and Southern clusters as a backup option, if it is decided that this would be preferable instead of a horticultural or aquacultural development.
- This project has been developed with the Green Heat Network fund in mind. An application could be made in the future, however for this project to be eligible for funding, more detail and certainty would be required in relation to the horticultural/aquaculture heat load in terms of heat demand, and ideally an MOU signed off by the developer.
- Prior to any funding application, DCC should seek to develop draft Heads of Terms (HOT's) and look to obtain MOU's detailing an intent to engage from each heat customer in the project scope area.

Table of Contents

Executive Summary.....	2
Introduction.....	2
Stakeholder Engagement.....	2
Horticultural/Aquacultural Heat Demand.....	2
Heat Supply	2
Financial Modelling.....	3
Counterfactual, and Heat Price	3
Results.....	4
Carbon Savings	5
Conclusions	6
1. Introduction.....	9
1.1 Overview	9
1.2 Pathway to Net Zero.....	9
1.2.1 Durham County Council	9
1.2.2 Heating contributions to UK emissions.....	9
2. Heat Demand Assessment.....	10
2.1 Southern District Heating Network	11
2.2 Northern District Heating Network.....	11
2.3 Aquacultural Load	12
3. Heat Supply	13
3.1 Background.....	13
3.2 Energy Centre Heating Technology	13
3.2.1 Operating Conditions	13
3.2.2 Solid Energy heat pump option.....	14
3.2.3 Carrier heat pump option.....	15
4. Energy Modelling.....	16
4.1 Scenario 1 – Southern Pipework and Aquacultural Load	18
4.2 Scenario 2 – Southern and Northern Pipework.....	20
5. Heat Network Modelling	22
5.1 Energy Centre Design	22
5.2 Network Routing.....	24
5.2.1 Southern Network	24
5.2.2 Northern Network.....	26
5.3 Customer connection design	27
6 Techno-economic Analysis.....	28
6.1 Approach.....	28
6.2 Modelling assumptions	28

6.2.1	Counterfactual.....	28
6.2.2	Heat Sale Prices	29
6.2.3	Energy Prices	30
6.3	Capital Costs	33
6.4	Operating Costs.....	36
6.4.1	Operation and Maintenance Costs	36
6.5	Revenues	36
6.5.1	Carbon offsetting.....	36
6.6	Economic Results	37
6.6.1	Gas Boiler Counterfactual	37
6.6.2	Gas Boiler Counterfactual Sensitivity Analysis	38
6.6.3	Decentralised ASHP Counterfactual	40
6.6.4	Decentralised ASHP Counterfactual Sensitivity Analysis	41
6.7	Carbon emissions.....	43
6.7.1	Emission savings for DHN.....	43
8.	<i>Risk management</i>	<i>45</i>
9	<i>Funding</i>	<i>51</i>
9.1	Green Heat Network Fund.....	51
9.2	Horden GHNF Eligibility	51
9.3	Other Funding Streams	53
10	<i>Reducing electricity costs using renewable energy technology</i>	<i>54</i>
10.1.	Investing in onsite or locally sourced renewable energy	54
10.2	Power purchase agreements	57
11	<i>Conclusions and next steps.....</i>	<i>58</i>
11.1	Key recommendations	61

1. Introduction

1.1 Overview

Horden is a historic coal mining town in County Durham. The Horden Colliery closed in 1987 and now presents the opportunity to provide a source of heat. This project aims to identify the potential to use mine water from this coal mine to produce cost effective, low carbon heat in a sustainable manor.

The temperature of water in the mine remains reasonably constant throughout the year. This project has designed several systems capable of recovering heat in the mine water using various heat pumps. Many commercial and residential buildings could be supplied with heat from these heat pumps through a district heating network.

1.2 Pathway to Net Zero

1.2.1 Durham County Council

In February 2019, Durham County Council (DCC) declared a climate emergency in recognition of the need to take immediate action against the potential threats of climate change. Subsequently, the council pledged to reduce carbon emissions from DCC's operations by 80% from 2008/09 levels by 2030, and investigate what further actions are necessary to make County Durham Carbon Neutral by 2050 and pledge to achieve this.

The council revised these targets in 2022. In addition to reducing their operation's real carbon emissions by 80%, DCC pledged to achieve net zero by 2030. They also brought forward the target of becoming carbon neutral to 2045.

1.2.2 Heating contributions to UK emissions

Heating accounts for over one third of the UK's greenhouse gas emissions³. To meet the UK Government's legally binding target of net-zero by 2050, household emissions from heating and hot water must be reduced by 95%⁴. Therefore, they must be reduced by the same amount in Horden.

The Committee on Climate Change CCC recommended that, to meet net zero targets, at least 18% of total UK heat demand should be delivered through heat networks, yet heat networks currently only provide around 2% of UK heat⁵.

Along with the electrification of heat and potential use of hydrogen for heating, district heating networks (DHNs) are a key component of the heat decarbonisation journey in the UK. DHN's allow the transitioning of heating to renewable energy sources for a large number of connected buildings. Durham County Council have embraced the concept of DHNs, by looking to establish several within their jurisdiction.

Regulations are moving towards phasing out gas boilers. It is likely that at some point in the future, they could be banned. UK official climate advisers recommend that all fossil fuel

3

https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/766109/decarbonising-heating.pdf

⁴ [Energy Savings Trust, 2019. Significant changes are coming to the UK heating market](#)

⁵ <https://www.theccc.org.uk/publication/element-energy-for-ccc-research-on-district-heating-and-local-approaches-to-heat-decarbonisation/>

boilers are banned by 2033⁶. This is a heavily debated subject as it could result in people being unable to heat their houses. Even with government grants, ASHP have high upfront capital costs. Building a DHN will therefore enable customers to avoid these high costs. It does, however, make creating a pricing mechanism difficult as when the fossil fuel boiler ban occurs, customers can be charged according to ASHP heat prices. This change has not been investigated due to uncertainties surrounding when this will happen.

2. Heat Demand Assessment

The buildings closest to the proposed energy centre location are either unheated or currently use electric heating and are therefore unsuitable for potential connection. Further afield, two main clusters of heat loads have been identified as potential areas that could be provided with heat.

To the south there is a cluster of buildings comprising of 49 domestic houses, Robinson Care Home, Seaview Health Centre, Minerva House and Jack Dormond Care Home. These could be connected to the minewater heat supply using a southern district heating network.

To the north there is a large housing estate of 224 domestic houses as well as Our Lady Star of the Sea Catholic School. These could be connected to the minewater heat supply using a northern district heating network.



Figure 1: Heat mapping of Horden

Following the identification of these key heat demands, site visits were conducted to all commercial buildings to more accurately estimate heating demand. During site visits District Eating identified building materials, heating systems, heat sources and enquired into how

⁶ <https://www.greenmatch.co.uk/blog/gas-boiler-ban>

the building was being used. From this the peak and annual heat demand were estimated using a modelling tool from the Carbon Trust.

The domestic hot water (DHW) demand has been estimated using a combination of a modelling tool from the Carbon Trust and CIBSE benchmark data for water usage. The variable load of the district heating network have been estimated using a building heat demand modelling tool from Carbon Trust. These models were based on building data recorded during site visits to Horden.

2.1 Southern District Heating Network

The heat demand estimates for the buildings in the southern district heating network scenario are displayed in Table 1.

Table 1: Southern district heating network building connections and heat demands

Building connection/housing cluster to be connected	Annual heat demand kWh	Modelled peak kW
Jack Dormond	244,191	96
Minerva House	12,253	31
Robinson House	156,799	84
Housing Estate South	892,058	368
Seaview Health Centre	24,652	58

Jack Dormand and Robinson House would be the main anchor heat loads of the southern heating network. As care homes are required to be heated to a relatively high temperature and are used continuously throughout the year, they tend to have a high and constant heat demand. The average heat demand for DHW has been estimated to be 18.2 and 10.1 kW for Jack Dormand and Robinson House respectively.

2.2 Northern District Heating Network

The Northern Cluster has a large residential demand. A significant anchor load has not been identified for the northern district heating network. The heat load of the school and domestic buildings of the northern housing estate would vary seasonally. Therefore, this cluster could be added as phased network extensions to the Southern network but may not be feasible on its own. Alternatively, if a horticultural or aquacultural development does not take place, the houses from the northern cluster could supplement heat offtake. If the housing cluster was connected, Our Lady School should also be connected due its location relative to the housing cluster.

Table 2: Northern district heating network building connections and heat demands

Building connection/housing cluster to be connected	Annual heat demand kWh	Modelled peak kW
Our Lady School	82,488	143
Northern Housing Cluster	5,415,856	1,977

2.3 Aquacultural Load

Initially, it was proposed that a greenhouse could comprise the main anchor load of the proposed heat network. However, discussion with local stakeholders made apparent that a glasshouse could become victim of vandalism and antisocial behaviour. It is therefore not recommended that a glasshouse is developed close to the proposed energy centre location.

The aquacultural load has been modelled as having a baseload of 500kW and a variable load of 1000kW. The baseload would be for heating the large quantities of water to approximately 28°C throughout the year⁷, and for a proportion of the building heating load. The building would itself need to be heated to a high temperature to minimise evaporation from the open prawn tanks.

Table 3: Heat demand of aquacultural load

Building connection/housing cluster to be connected	Annual heat demand kWh	Modelled peak kW
Aquacultural load	5,440,363	1,500

⁷ <https://www.llyn-aquaculture.co.uk/index.php?p=77>

3. Heat Supply

3.1 Background

The heat source for the proposed heat networks is water-source heat pumps utilising mine water, and a hydrogen compatible gas boiler. Townrock Energy conducted a study assessing the quantity of heat available from the mine water.

Key findings from Townrock Energy's heat abstraction and supply report include:

- Under a sustainable abstraction scenario, mine water at a design flow rate of 40 L/s can enter the heat exchanger within the plant room, and be cooled by 8 °C (i.e. from around 16 to 8 °C). This will provide up to 1.34 MW of thermal energy to a secondary, process fluid on the heat pump inlet side of the scheme.
- A gasketed plate heat exchanger, made with titanium-based plates (or equivalent, e.g. marine- grade steel), capable of cooling mine water by a DT of 8 °C and operating at an approach temperature of 1.5 – 2 °C should be selected for next stage design work.
- A similar, underground reinjection pipeline running from the plant room building to the rising main closely downstream from the abstraction point, delivering cooled, mine water back into the existing infrastructure.

3.2 Energy Centre Heating Technology

3.2.1 Operating Conditions

During the first stage of the project, Two systems were investigated; “medium temperature” and “high temperature” heat pumps; these scenarios assume that the network operates at a constant temperature of either 70 or 85°C .

Following this, the decision has been made to decrease the network flow temperature to between 65 and 75°C. District Heat Network (DHN) heat pumps, which are more efficient, perform optimally at lower temperatures of around 60 °C, and existing boilers could have their flow temperatures reduced to 60^{°8} during periods where the heating demand is less such as spring, summer and autumn.

Existing heating systems in buildings consist of gas-fired boilers that supply hot water to wall-mounted radiators. These boilers operate at flow temperatures ranging between 70°C to 80°C. A heat pump system would perform optimally at lower flow temperatures. It is important to assess heating infrastructure and building fabrics in buildings to determine whether they are suitable for lower flow temperatures. If not, retrofits may be required.

For instance, in the case of Robinson House, the estimated heat output of the current radiators is 34 kW with a flow temperature of 76.2°C during the site survey. The impacts of reducing the flow temperature in cold weather to 75°C would therefore be minimal, and it is possible that the existing radiators can suffice without replacement under certain conditions. In some buildings, it may be necessary to install larger or additional radiators to ensure adequate heat distribution in rooms at lower flow temperatures.

⁸ <https://www.gov.uk/government/news/government-joins-with-households-to-help-millions-reduce-their-energy-bills>

Heat losses could be minimised reduced by Improving the insulation and sealing airtightness of the buildings before connecting to the network DHN, and would further reduce the peak loads. Heat losses can be minimized by enhancing insulation and addressing any reducing draughts, and this could largely alleviate the need for larger radiator upgrades.

Regarding insulation, one crucial aspect of wall insulation retrofit is cavity wall insulation could be considered. Installing cavity wall insulation is often a cost-effective measure with a payback period of around 3-5 years⁹. It causes less disruption to building use compared to internal or external insulation. However, if the cavity has some existing insulation it is unlikely that new cavity wall insulation could be installed. This is because older types of cavity insulation tend to slump and can become detached from the inner cavity walls over time, making it impossible to achieve an even cavity fill without uninsulated 'cold spots'. In addition, without sealing the cavity, applying external wall insulation would have a limited impact in reducing heat loss and improving energy efficiency because most of a building's heat loss is from the inner wall into the ventilated cavity from where heat is carried away. Moisture, condensation, and mould are potential issues when cavity wall insulation is not properly installed. However, in Scotland, where external render is commonly applied, cavity wall insulation has higher success rates. The external render provides enhanced rainwater protection, reducing the chances of water tracking across the filled cavity. Moreover, Scottish housing standards emphasize adequate ventilation to allow for the escape of internal humidity. These factors contribute to a lower incidence of problems such as internal mould growth compared to regions where external render is less prevalent.

3.2.2 Solid Energy heat pump option

Heat pumps from Solid Energy and Carrier have both been investigated for this project. Both can produce temperatures up to 85°C and would be able to meet the heat demands of the network even if the gas boiler is out of operation.

An overview of Solid Energy heat pumps is shown in Table 4 below. From this it is clear that reducing the flow temperature could lead to significant improvements in the efficiency heat pumps.

Table 4: Solid Energy Heat Pump Performance

Solid energy			
Variable		LWB252SI	LWB203SI
Performance when flow temperature is 65°C	Max Heat output (kW)	1017.3	877.4
	COP	3.91	3.44
Performance when flow temperature is 70°C	Max Heat output (kW)	1017.8	887.7
	COP	3.53	3.09
Performance when flow temperature is 85°C	Max Heat output (kW)	1017.2	895.5
	COP	3.19	2.78

It should be noted that these values represent the worst-case performance of COP and have been calculated assuming that minewater would be extracted at the maximum value of

⁹ Energy Institute: Energy management essential

40L/s. Higher COP could be achieved by reducing the quantity of water extracted. They also assume a constant return temperature of 45°C which is not representative of the proposed heat network.

3.2.3 Carrier heat pump option

A Carrier heat pump has also been investigated as a potential heat source. This would use two 61XWLZE 14 heat pumps from Carrier as heat sources.



Figure 2: Carrier heat pump

Figure 3 shows the variation of COP with flow temperature on the condenser side and outlet temperature on the evaporator side. For this project the minimum evaporator outlet temperature would be 6.2°C. By extracting more water for the mine, a higher outlet temperature and thus COP can be achieved. This should be implemented during times at which the peak demand is not required.

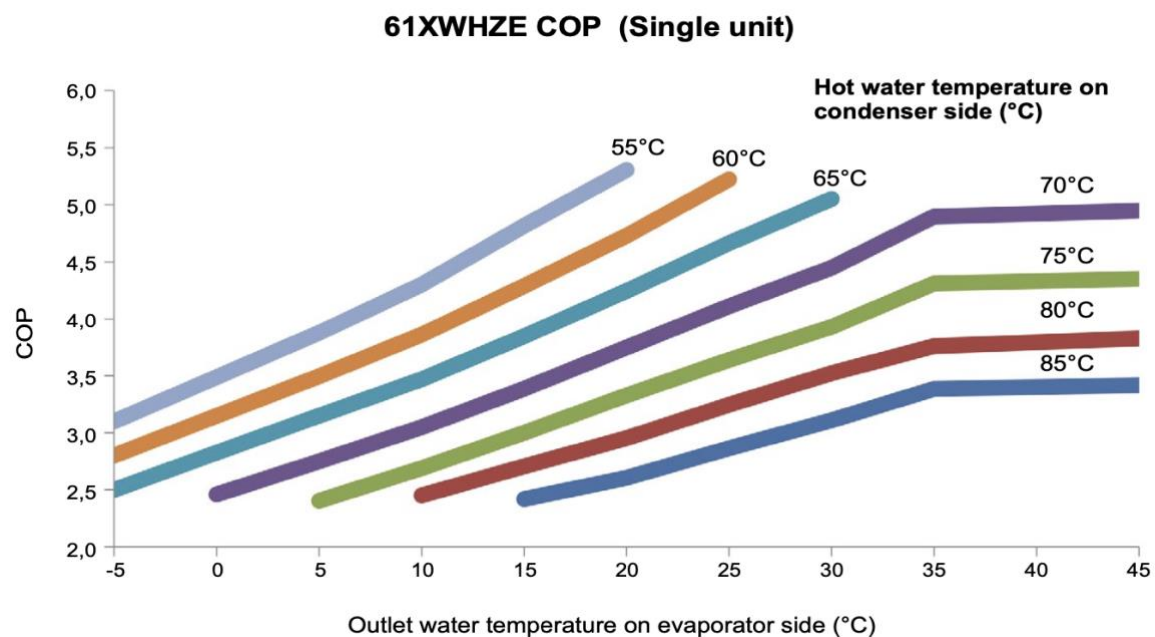


Figure 3: Carrier heat pump COP curves

4. Energy Modelling

An hourly heat demand profile for the duration of the year has been estimated using degree day data, the baseline temperature of buildings and the peak demand profile. This methodology is outlined in Figure 4.

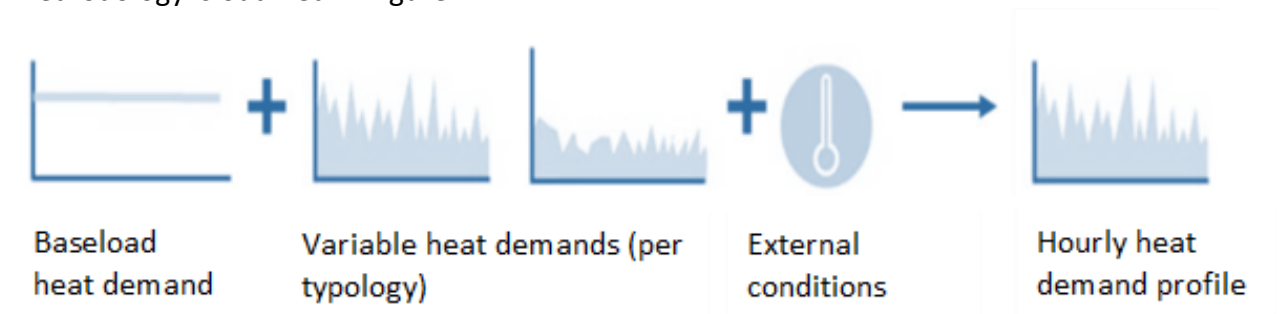


Figure 4: Energy modelling methodology

The flow temperature of the network will be selected using the weather compensation curve shown in Figure 5. For most of the year the flow temperature of the network will be 65°C and will only increase to 75°C during the coldest winter days. This will increase the seasonal coefficient of performance (SCOP) of the heat pumps and result in less electricity usage for the same quantity of heat production. As the operating temperatures of existing heating systems will change, system control will have to be adjusted.

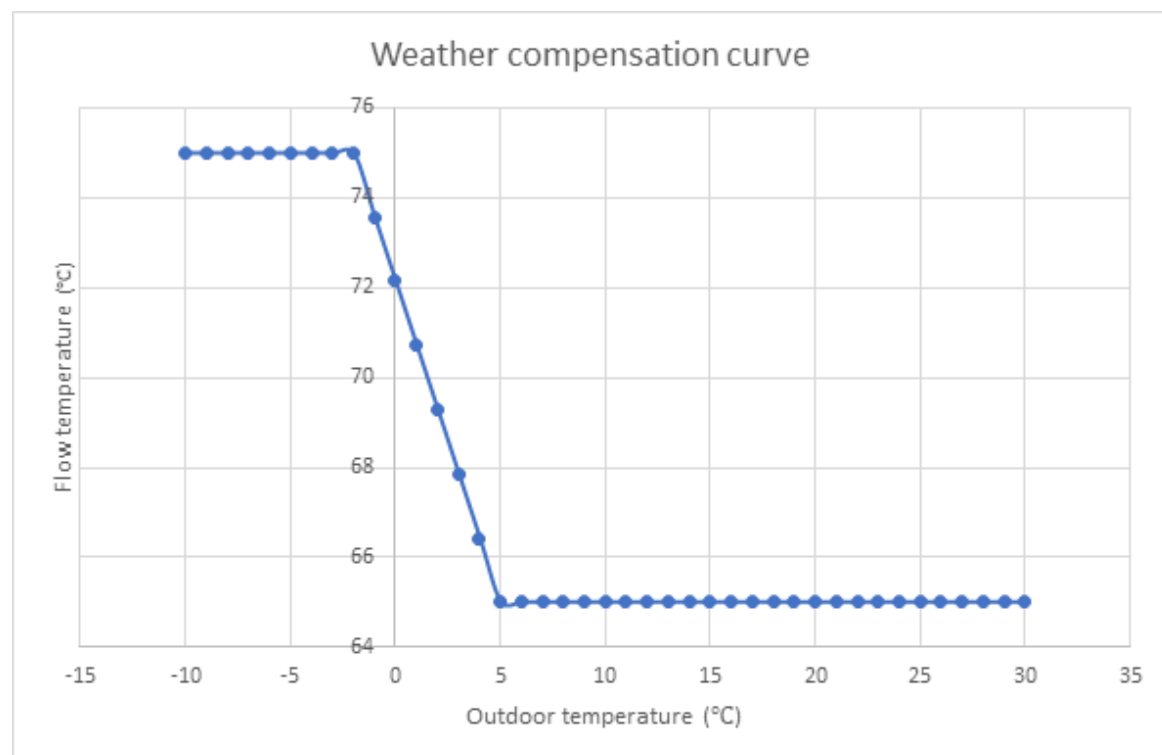


Figure 5: Weather compensation curve of the district heating network

The hourly heat profile has been further developed to produce an hourly heat supply profile. This was completed using the previously calculated hourly heat demand profile, the weather compensation curve previously discussed in Figure 5 and allowed for the modelled heat production profiles of both the heat pumps and the gas boiler. This methodology is shown in Figure 6.

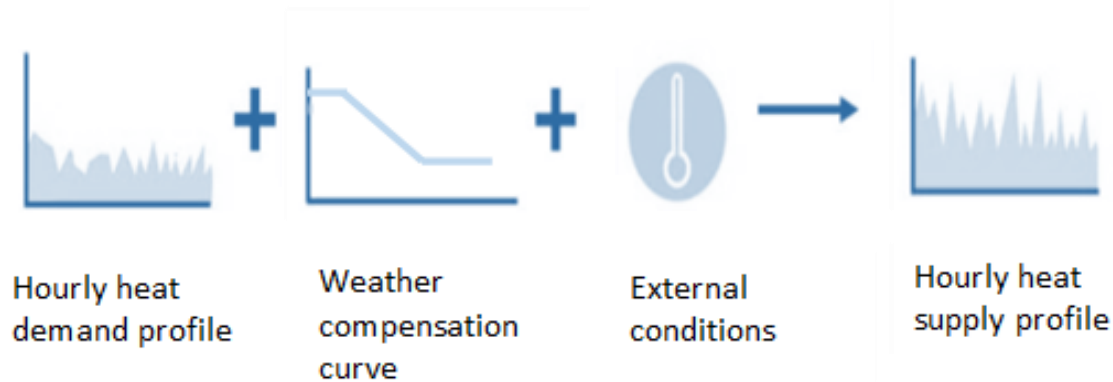


Figure 6: Hourly heat supply profile modelling methodology

The flow and return temperatures of the aquacultural load have been assumed to be 60°C and 30°C respectively. The return temperature of the district heating networks has been assumed to be 45°C. The flow temperature of the network varies between 65°C and 75°C according to the weather compensation curve. The return temperature to the heat pumps for scenario 1 therefore varies according to both the demand of the southern heat network and the aquacultural load as well as the weather compensation curve. Due to this, the return temperature to the pumps has then been calculated for each scenario using a thermodynamic modelling tool shown in Figure 7. This allowed the performance of the heat pumps to be more accurately modelled by accounting for the variability in flow temperature.

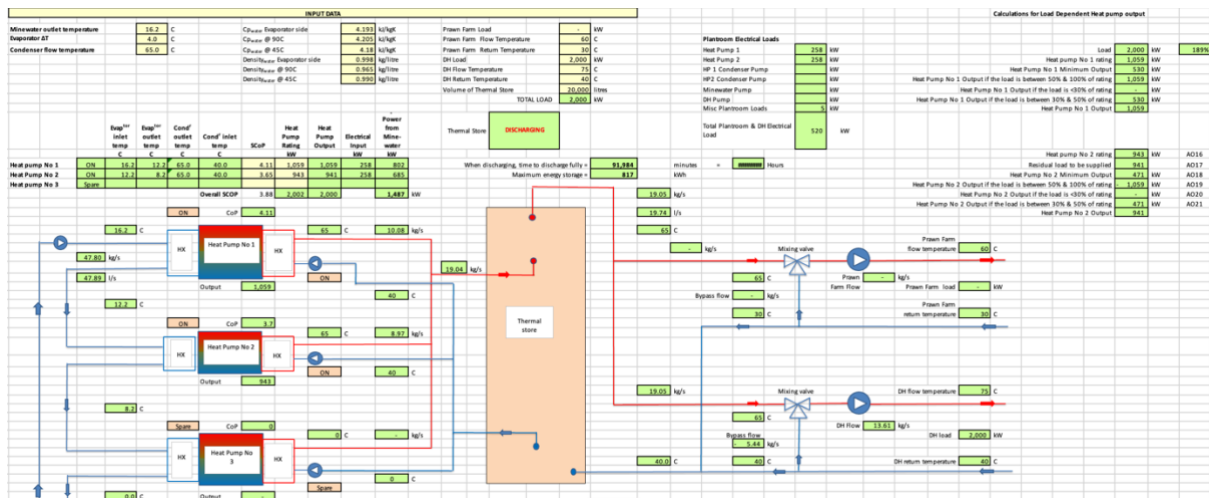


Figure 7: Thermodynamic modelling of plantroom

4.1 Scenario 1 – Southern Pipework and Aquacultural Load

In Scenario 1, heat is supplied to the southern cluster and an aquacultural load. This can be seen in Figure 8.



Figure 8: Heat mapping and network layout of scenario 1

Using the results of heat demand assessments, the hourly heat demand profile of scenario 1 has been estimated. This profile is shown in Figure 9.

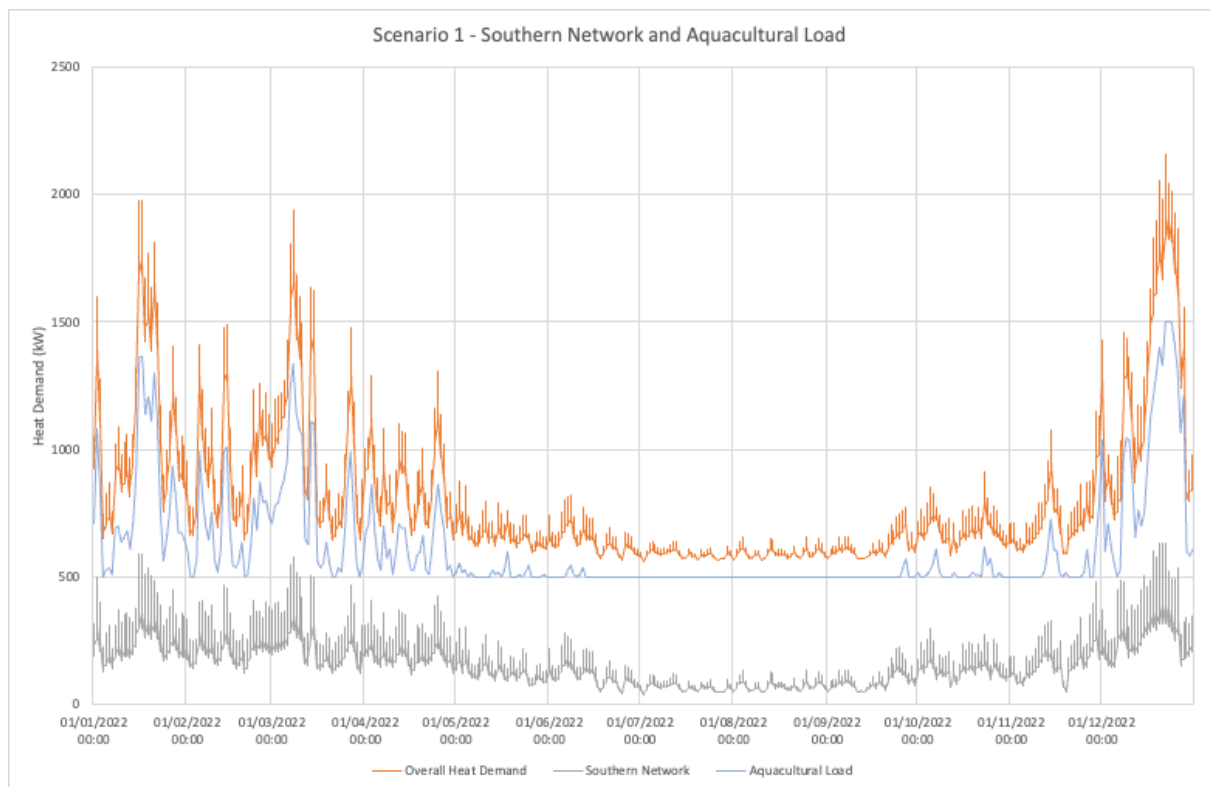


Figure 9: Scenario 1 heat demand profile, note the blue line depicts the assumed aquacultural load.

This hourly heat demand along with the weather compensation curve and heat pump COP performance have been used to produce a heat supply profile (Figure 10). The graph shows the heat supply from the heat pumps as well as the gas boiler throughout the year.

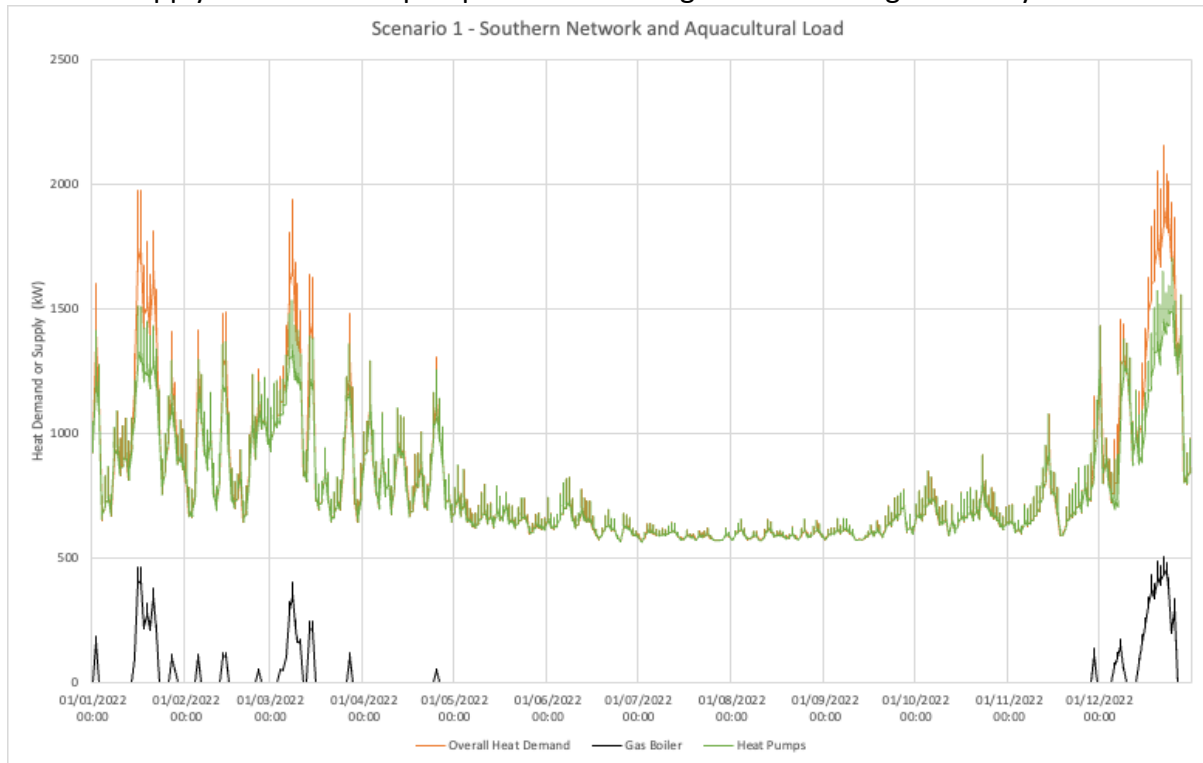


Figure 10: Scenario 1 heat supply profile

For most of the year the heat pump can solely be used to meet the weather compensation curve and heat demand requirements. Gas boiler usage has been minimised to times that require the higher operating temperature.

As the flow temperatures of the southern district heating network and aquacultural load are different, the return temperatures to the heat pumps will vary over the year. This effect was modelled using the thermodynamic model previously discussed. The range of COP of the Solid Energy heat pump has then been assessed using models provided by the manufacturers. This is shown in Table 5. The average COP of the system has been modelled and assumed to be 4.35, as for most of the year the return temperature will be lower which will improve the performance of the heat pumps.

Table 5: Scenario 1 Solid Energy heat pump performance

Value	Minimum heat load conditions	Maximum heat load conditions
Return temperature modelled (°C)	31.7	33.8
COP Solid Energy	4.46	4.15

Carrier were unable to provide heat pump models so the effect of different return temperatures has not been investigated. The COP has been estimated to be a minimum of 3.36 using data provided by the manufacturer. According to Carrier, the overall COP can be improved 4-7% by having 2 heat pumps connected to each other. The impact of this has not been investigated.

4.2 Scenario 2 – Southern and Northern Pipework

Scenario 2 comprises the network described in Scenario 1 with an additional branch connecting the northern cluster. This scenario represents a case in which an aquacultural project is not developed in Horden.



Figure 11: Heat mapping and network layout of scenario 2

Using results of heat demand assessments, the hourly heat demand profile of scenario 2 has been estimated. This profile is shown in Figure 12.

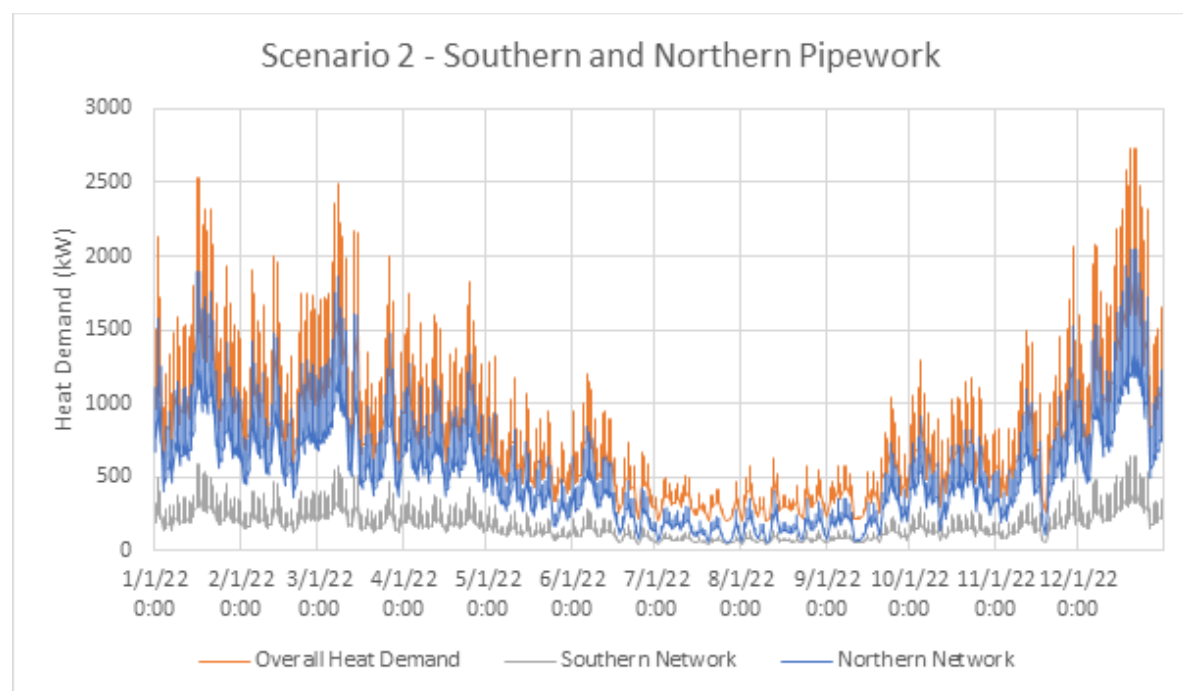


Figure 12: Scenario 2 heat demand profile

This hourly heat demand above along with the weather compensation curve and heat pump COP performance have been used to produce Figure 13. This graph shows the heat supply from the heat pumps as well as the gas boiler throughout the year.

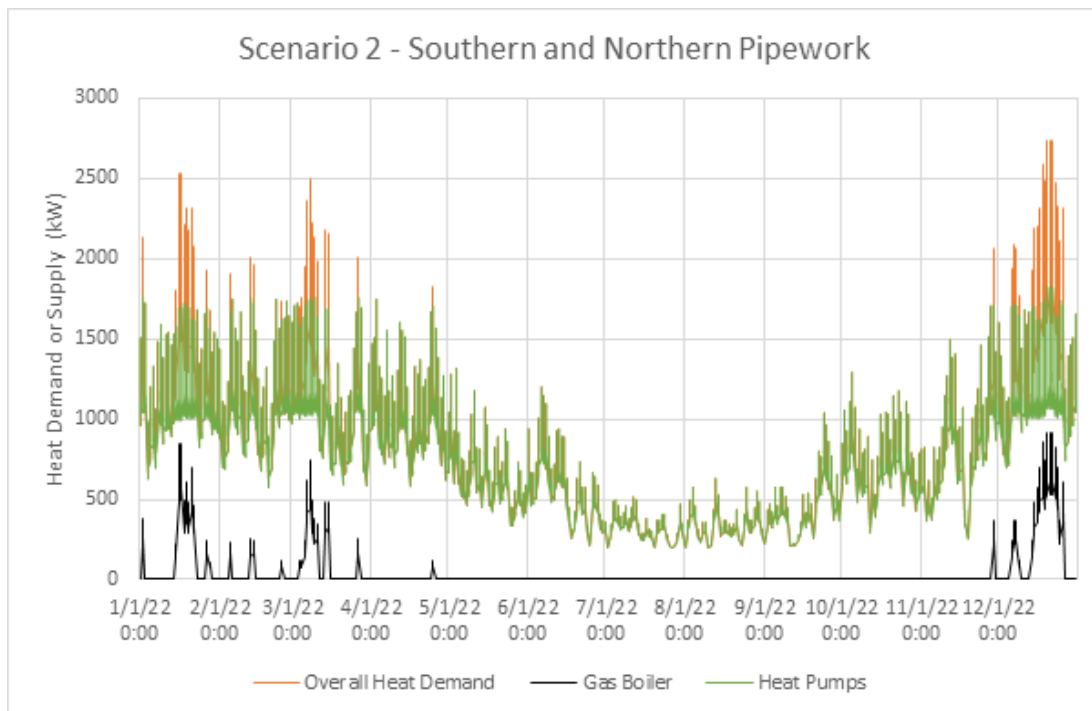


Figure 13: Scenario 2 heat supply profile

For most of the year the heat pump can solely be used to meet the weather compensation curve and heat demand requirements. Gas boiler usage has been minimised to times that require the higher operating temperature. As scenario 2 is used to supply heat loads all at the same flow and return temperatures, the heat pump COP will not vary.

Table 6: Scenario 2 Solid Energy heat pump performance

Value	Solid Energy heat pumps	Carrier heat pumps
Return temperature modelled (°C)	45	45
COP Solid Energy	4.03	3.36

5. Heat Network Modelling

5.1 Energy Centre Design

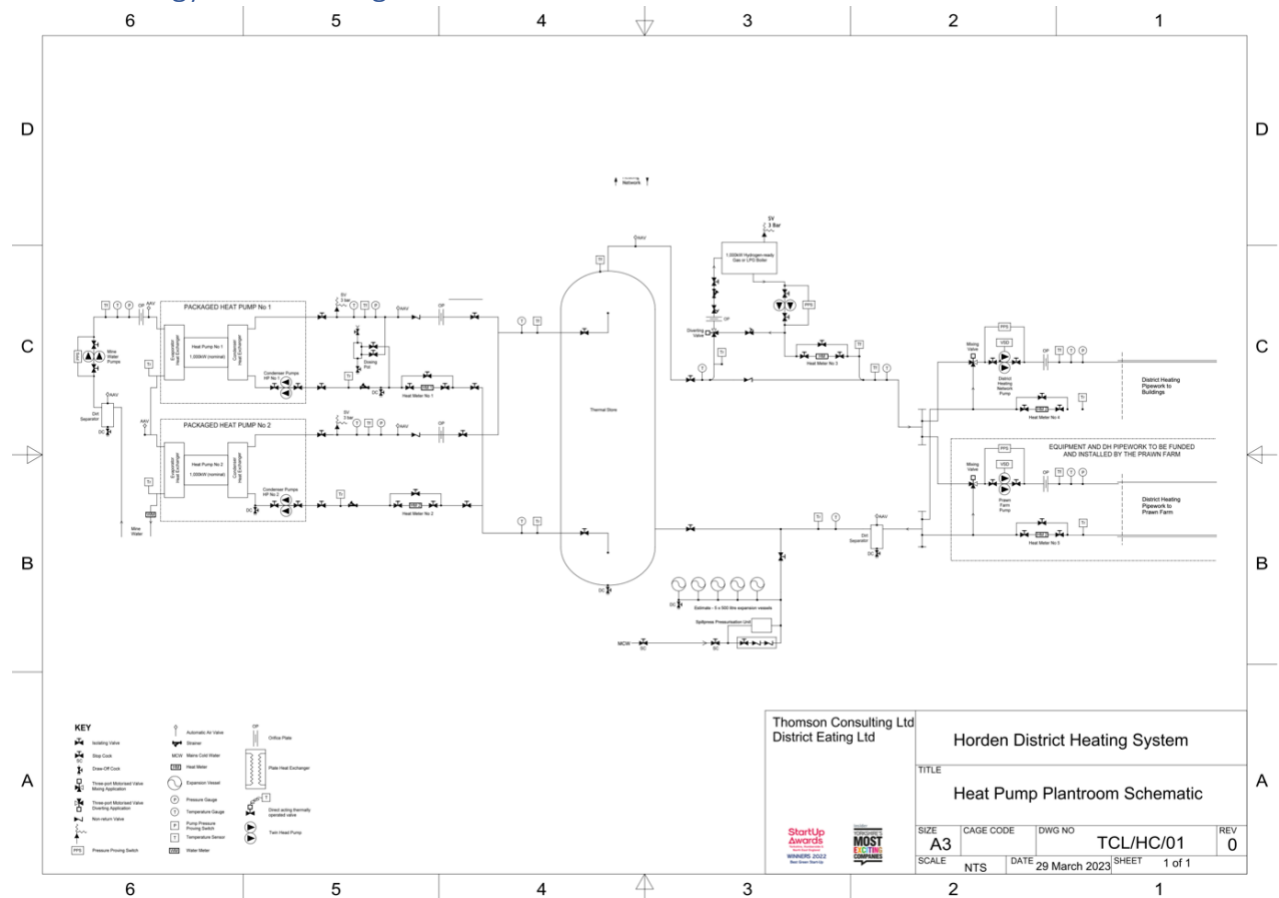


Figure 14: Heat pump plantroom schematics

The plant room would contain two heat pumps which would be used to provide heat to a 15,000 L thermal store, which would store up to 613kWh of heat. Although hourly profiling indicated that a thermal store is not required to meet the peak demand, including one could allow the system to use cheaper nighttime electricity prices. This heat can then be used during peak electricity hours to reduce electricity costs. A 1MW hydrogen compatible, gas Bosch boiler will be used as a back-up boiler for when the heat pumps require maintenance or repairs. The boiler will also be used to top up heat to meet flow temperatures higher than 65°C during periods when weather conditions require it.

The energy centre layouts displayed in Figure 15 estimate a footprint of 84m². This estimation takes into consideration various factors, including equipment size, allocation of space for auxiliary equipment, safety and accessibility requirements, and provisions for future expansion.

However, it is important to note that this is an initial estimation. As there is no industry standard benchmark for the physical size requirements of an energy centre, there is a possibility that the provided estimation may underestimate the actual size. During the next stage of detailed design, it is recommended to conduct a more comprehensive assessment, which should consider factors such as pipe layout, movement and maintenance requirements, internal heights, and other relevant considerations.

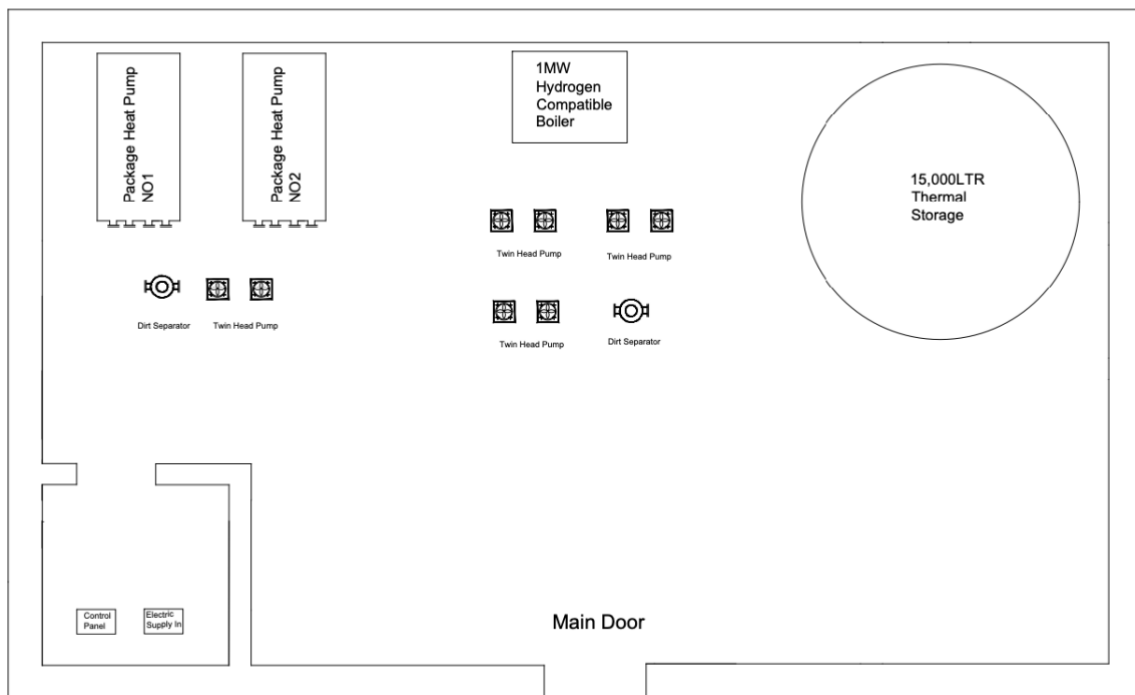


Figure 15: Heat pump plantroom layout

5.2 Network Routing

5.2.1 Southern Network

The Pipe layout in Figure 16 shows the proposed network route of the southern district heating network.

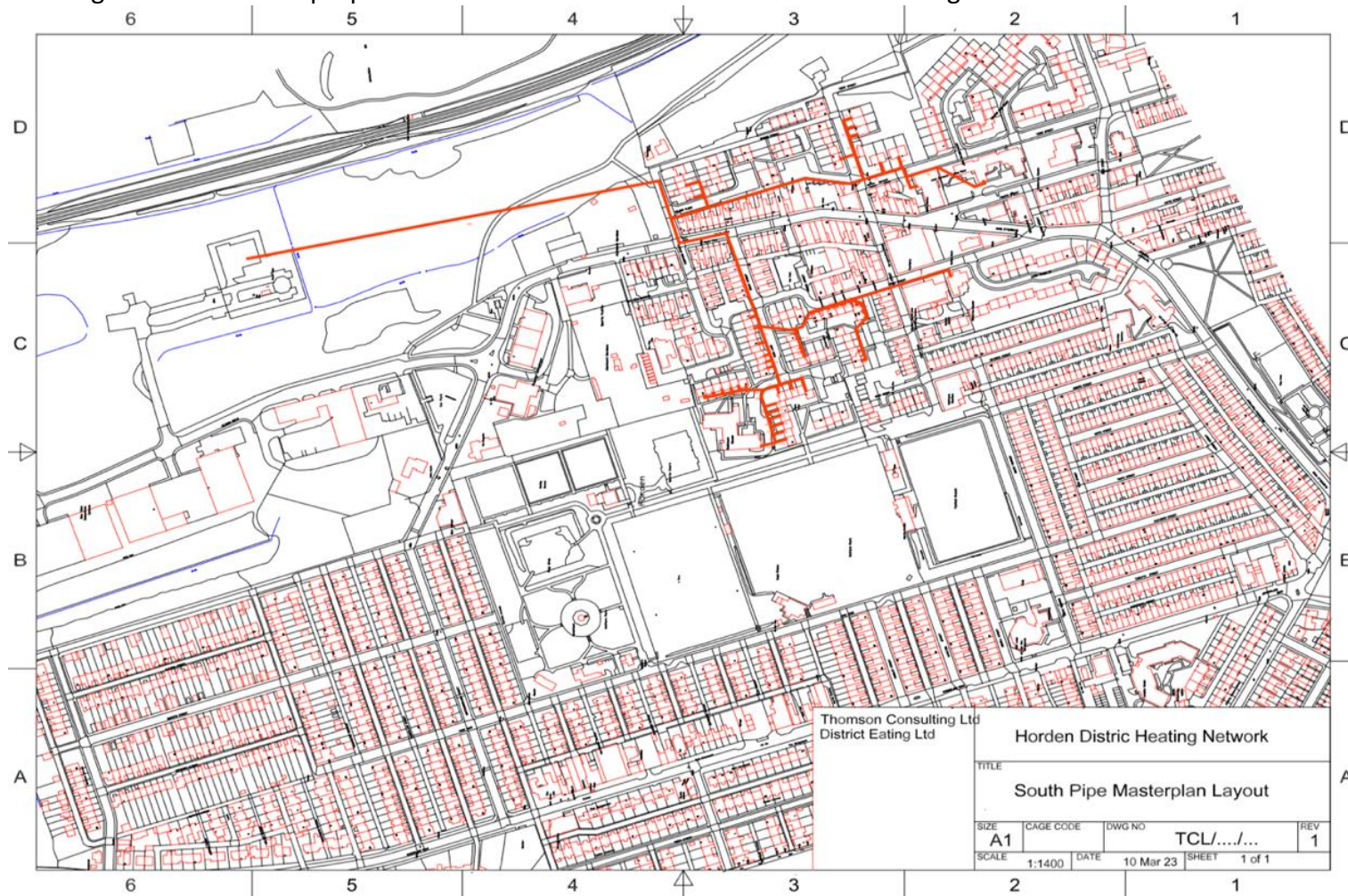


Figure 16: Southern Pipe Layout

The pipe schedule for the southern network is shown in Table 7. This schedule was configured accounting for DHW and heating diversity of both commercial and domestic buildings and meets the CIBSE CP1 design requirements. The pipe costs have been estimated using values for Rauthermex duo and uno pipe from REHAU. The heat loss from these pipes has been calculated to be 21.7kW when the flow and return temperatures of the network are 75 and 55°C respectively. As the network will operate below these temperatures for most of the year, losses could be less in reality. For analysis the heat loss value of 21.7kW has been used.

Table 7: Southern network pipe schedule

Type of pipe	Pipe length (m)	Installed Cost (£/m)	Total cost (£)
DN20 Duo	310.6	£71.15	£22,099.19
DN25 Duo	228.3	£80.34	£18,341.62
DN32 Duo	19.1	£106.09	£2,026.32
DN40 Duo	252.1	£142.92	£36,030.13
DN50 Duo	477.4	£186.37	£88,973.04
DN80 Uno	800.5	£169.24	£135,476.62

5.2.2 Northern Network

Figure 17 shows the proposed network route of the northern district heating network.



Figure 17: Northern district heating network

The pipe schedule of the northern pipework has not been calculated due to the uncertainty of its feasibility as a stand-alone district heat network. The total trench length is approximately 5,977m. Using relative costs based on the southern network, the northern network has been estimated to cost £7,256,655. Heat loss has been estimated to be approximately 75kW in total. As costs and heat losses have been estimated based on the southern network there is some uncertainty in these values. The network would likely cost less as smaller pipes could be used due to the smaller heat loads of the domestic buildings.

5.3 Customer connection design

The existing and proposed heating system for Langley House Care home is shown in Figure 18. Please note that it was decided not to connect Langley House Care Home to the heating network as no other appropriate heat loads were near to it. It has been included to demonstrate how buildings would be connected to the heat network which will be investigated at the next stage of the project.

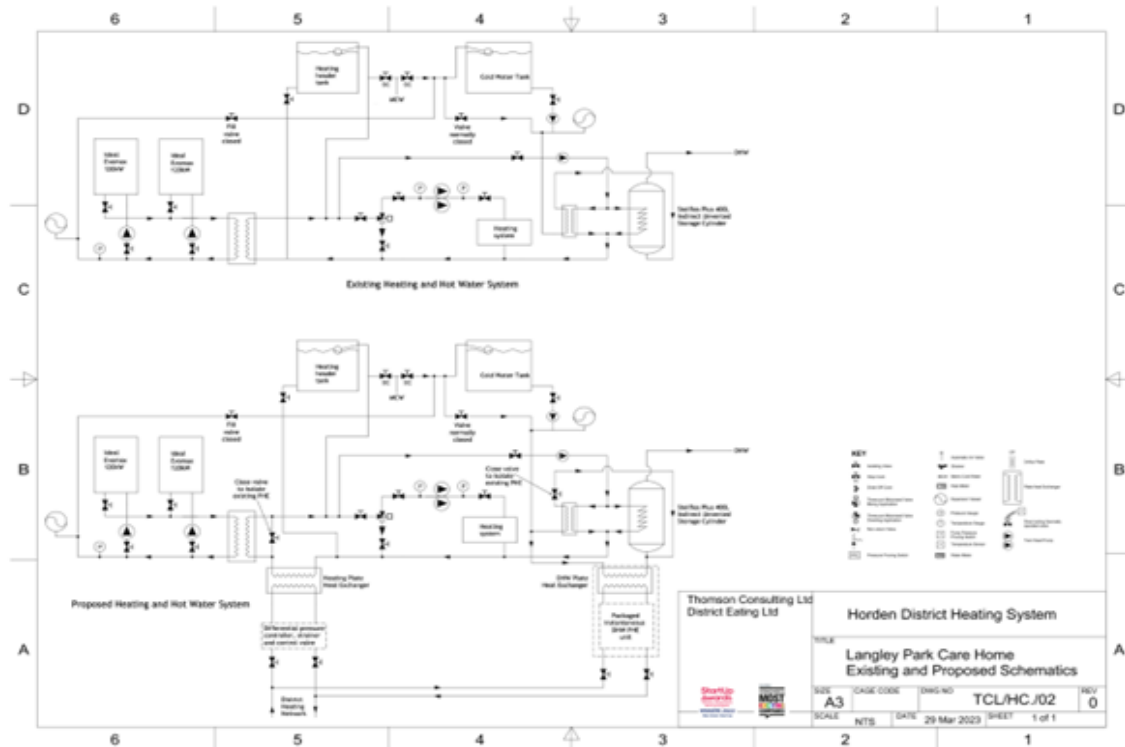


Figure 18: Existing and proposed schematics of Langley Park Care Home heating system

The heat exchanger will be installed on the main return pipe. This will allow the district heating system to indirectly heat the buildings' heating system. Many of the heating systems observed appeared to be old and likely contained large amounts of sludge in them. This heat exchanger will therefore protect the district heating network from the damage that could be caused by the buildings' varied age and quality of heating infrastructure.

A differential pressure controller, strainer and valve control will be present before the heat exchanger to ensure that the system operates safely and efficiently. A heat interface unit (HIU) will be connected to the DHW system, allowing the district heating to provide hot water to users. Care must be taken to ensure that DHW is always heated to at least 60°C to meet legionella safety requirements¹⁰. The HIU will come as a packaged instantaneous DHW plate heat exchanger unit that will be able to meet the users' hot water demands.

The plate heat exchanger for the space heating and DHW will be sized according to the users' requirements. This will be determined by assessing the existing size of the heating and hot water boilers, as well as using CIBSE benchmarks for DHW usage and building simulations for heating requirements.

¹⁰ <https://www.hse.gov.uk/legionnaires/things-to-consider.htm>

6. Techno-economic Analysis

6.1 Approach

A techno-economic cashflow model (TEM) has been set-up to assess the possible return on investment which each scenario can achieve over a 40-year time period. A TEM was built in MS Excel to analyse the combined technical details of the scheme (capital and operational) with appropriate cost/price inputs to generate an annual cash flow. This enabled an assessment of the viability (pre-tax) using Net Present Value (NPV), Internal Rate of Return (IRR) and discounted payback as key indicators.

Key assumptions for the TEM include:

- Heat is sold to each building according to counterfactual heat price for domestic or commercial buildings.
- For the gas boiler counterfactual, heat is sold at the levelized cost of heat for a gas boiler.
- For the ASHP counterfactual, heat is sold at 95% of the levelized cost of heat for an ASHP.
- Levelized cost of heat has been broken into fixed and variable components. Fixed component is associated with CAPEX, OPEX and REPEX and variable component is associated with energy costs.
- Fixed component of levelized cost has been estimated on a case by case basis and aligns with costs from Assessment of the Costs, Performance, and Characteristics of UK Heat Networks¹¹.
- Variable component of overall levelized cost of heat has been estimated assuming gas boiler is 85% efficient and ASHP has a COP of 2.2. BEIS energy forecasts have been used to calculate energy cost associated with variable component on a year-by-year basis.

6.2 Modelling assumptions

6.2.1 Counterfactual

The carbon assessment is presented as an absolute carbon emissions reduction against the counterfactual case. The counterfactual carbon emissions refer to the emissions generated by the connected buildings if they were not connected to the DHN, and therefore are reliant on their own plant room. The emissions generated by the building's plant room varies between the two counterfactual options proposed in this report:

- **Isolated natural gas boilers:** Each individual building would continue to operate using individual gas boiler at 85% efficiency and fulfilling all of the heating demand.
- **Decentralised ASHP:** Each individual building would be heated using an individual ASHP with a COP of 2.2.

11

https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/424254/heat_networks.pdf

6.2.2 Heat Sale Prices

Due to the HNDU Feasibility Study Specification, domestic properties and micro-businesses must not be offered a price of heat greater than a low carbon counterfactual for new buildings and a gas/oil counterfactual for existing buildings. As all buildings connected to the proposed network are existing, heat must not be charged at a rate higher than their projected costs for gas. It is likely that existing buildings will have to use low carbon heating technologies soon due to regulations, so heat pricing has been calculated for both counterfactuals.

The levelized cost of heating estimates the average cost of providing one kWh of heat over the lifetime of the equipment, considering the capital cost of the equipment and installation and the operating costs of fuel and regular maintenance. This has been estimated for the buildings connected using both existing gas boilers and heat pumps. These values represent the maximum cost that customers can be charged for heat from the network.

For the gas boiler counterfactual, heat has been assumed to be sold at the levelized cost of heat. For the ASHP counterfactual, heat has been assumed to be sold at 95% of the counterfactual to encourage users to connect to the network.

The levelized cost has been broken into a fixed yearly component and a variable component. The fixed yearly component is comprised of the capital cost of the heat spread out over the lifetime to the heating technology as well as annual repair and service costs. The user therefore pays for the counterfactual heating technology over the lifetime of the project, incentivising them to join the network. Table 8 shows an overview of the fixed components of the levelized costs of heat from counterfactuals. These have been calculated using the method in “Assessment of the Costs, Performance, and Characteristics of UK Heat Networks”¹² and align with the values from this report.

Table 8: Fixed component levelized costs of counterfactuals

Heat Demand	Annual heat demand (kWh)	Fixed component of levelized cost of heat for gas boiler (£/kWh)	Fixed component of levelized cost of heat for ASHP (kWh)
Jack Dormond	244,191	£0.0038	£0.02
Our Lady School	82,488	£0.0151	£0.08
Minerva House	12,253	£0.0444	£0.19
Northern Housing Cluster	5,415,856	£0.0185	£0.07
Robinson House	156,799	£0.0055	£0.03
Housing Estate South	892,058	£0.0246	£0.09
Seaview House	24,652	£0.0272	£0.13
Horticultural load	5,440,363	£0.0018	£0.01

The variable component of the heat price has been calculated on a year-by-year basis based on the BEIS commercial and domestic electricity and gas prices. The forecast for overall levelized costs that heat prices have been based on is shown graphically in Figure 19. If this forecast is compared to the BEIS energy price forecast (Figure 20), energy costs represent the main component of heat prices.

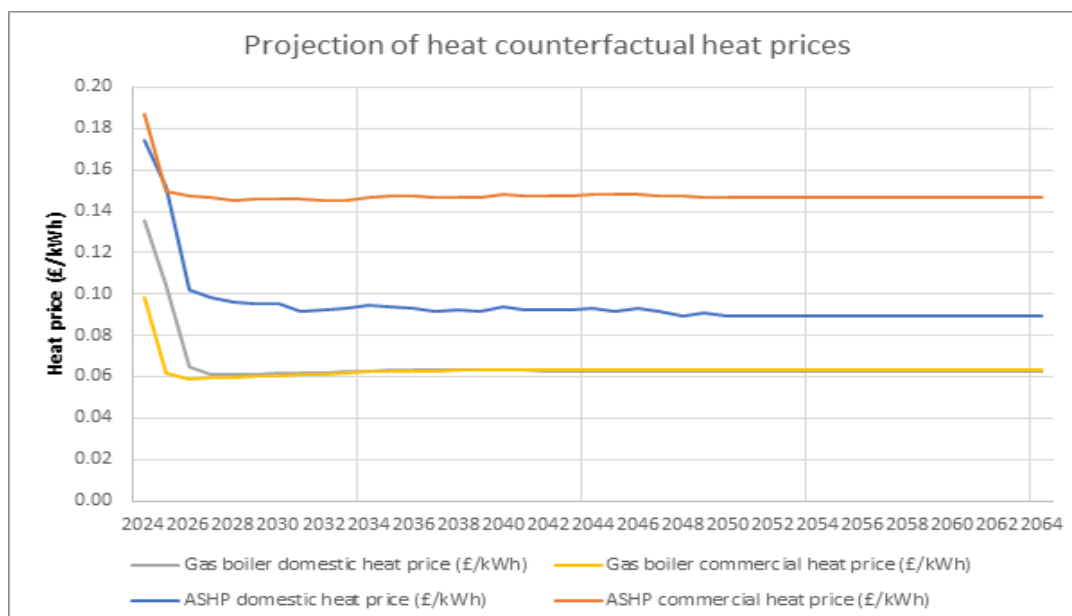


Figure 19: Projected counterfactual heat price

Users could be charged a connection cost when they connect to the network. This would usually be set to the associated cost of the counterfactual heating technology. As the levelized costs of heat incorporates this cost this has not been incorporated into the heat pricing mechanism. This has a significant benefit of allowing customers to gradually pay for the cost of connecting rather than paying a large sum and so encourages them to connect to the network.

6.2.3 Energy Prices

Energy costs have been calculated on a yearly basis. An overview of this is shown in Table 9.

Table 9: Energy costs

ITEM	How costs have been derived
Electricity for running the heat pumps	Electricity prices have been modelled in 4 ways; BEIS forward price projections
Electricity for running the DH pump	PPA pricing ¹³ LCOE wind energy ¹⁴ . Transmission costs from Northern Powergrid ¹⁵
Gas for running the gas boiler	BEIS forward price projections

¹³ <https://app.pexapark.com/api/ppa-times/31/document>

¹⁴

https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/911817/electricity-generation-cost-report-2020.pdf

¹⁵ [https://www.northernpowergrid.com/sites/default/files/assets/Northern Powergrid %28Northeast%29 - 2023-24 LC14 Charging Statement - v0.3.pdf](https://www.northernpowergrid.com/sites/default/files/assets/Northern%20Powergrid%20Northeast%202023-24%20LC14%20Charging%20Statement%20-v0.3.pdf)

Energy price forecasts from the Department for Business, Energy & Industrial Strategy (BEIS) have been used to model the economics of energy costs. It is worth noting that the recent volatility in energy markets has made forecasting difficult and BEIS forecasts may be inaccurate.

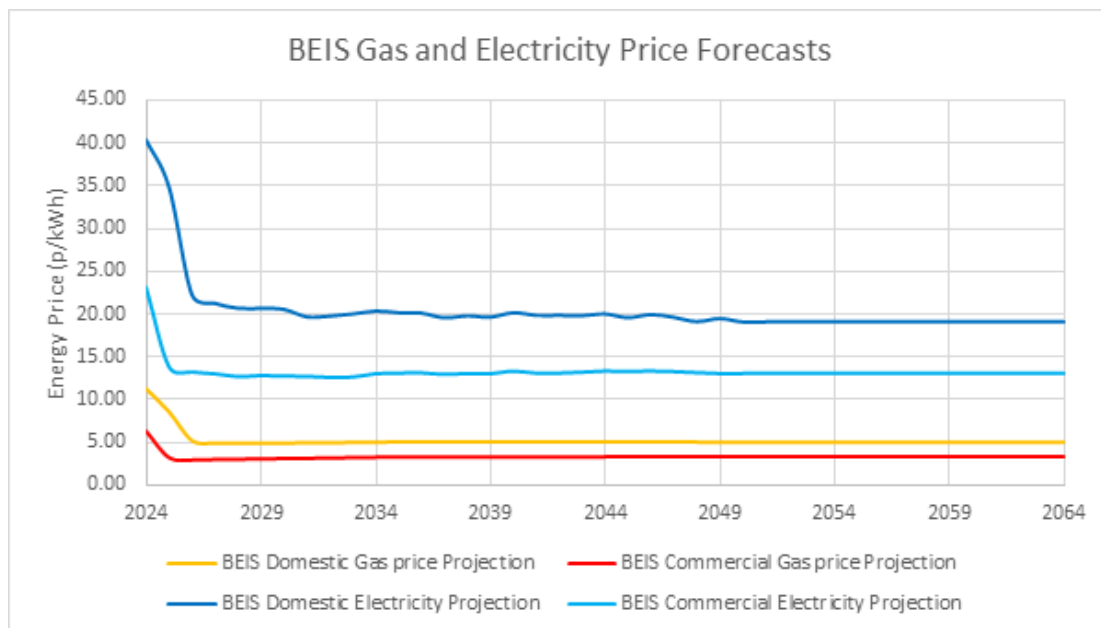


Figure 20: BEIS Gas and Electricity Price Forecasts

Counterfactuals have used energy prices according to the type of user. For example, Minvera House Care Home, a commercial building, has been modelled using commercial energy price. The energy usage of the heat sources of the district heating network have been charged using commercial energy prices.

The use of day and night-time tariffs could be used to reduce electricity costs. This would be achieved by charging the thermal store when electricity is cheap during the night and using this heat during peak hours (known as 'Economy 7'). This has been modelled and estimated to reduce average electricity costs by approximately 13%. The difference between day and night-time prices has in recent years decreased slightly as more people have become aware of the advantages of using Economy 7. As Economy 7 forecasts are not available at present, the long-term impacts of using this energy price mechanism have not been investigated.

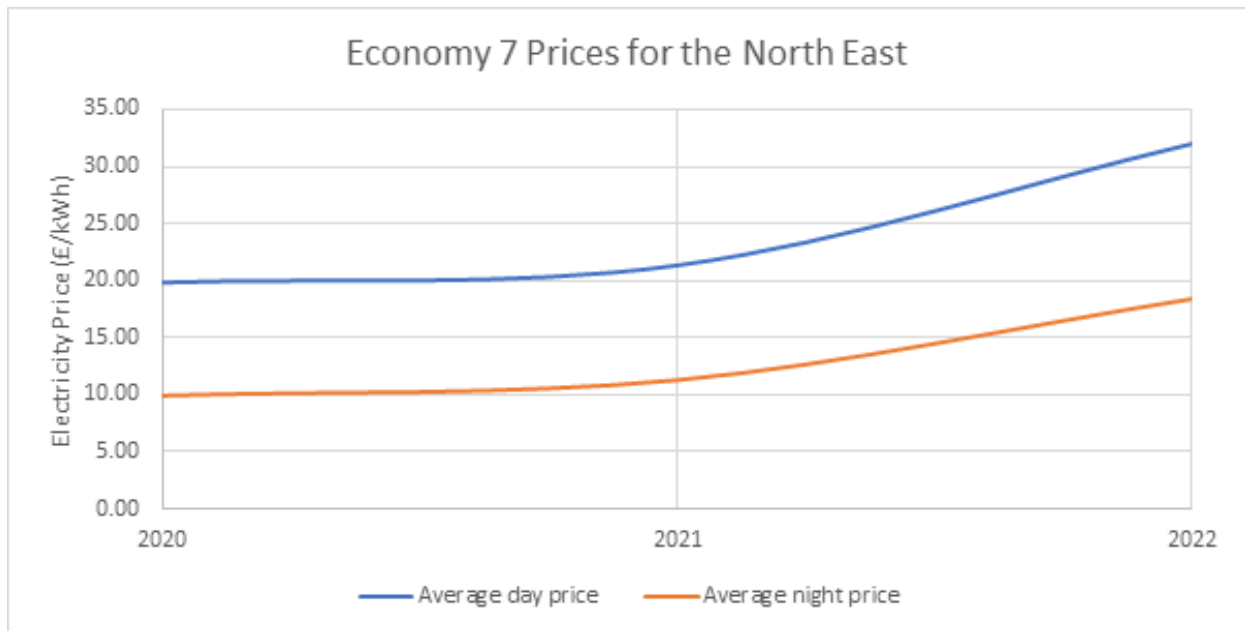


Figure 21: Economy 7 prices

Renewables could be used to provide electricity to the heat pumps at a lower cost than commercial electricity prices. This would be achieved either by investing in the renewable energy technology which would provide electricity at the levelized cost, or by entering a power purchase agreement (PPA) with a renewable energy generator. An overview of these electricity prices is shown in Figure 22 below.

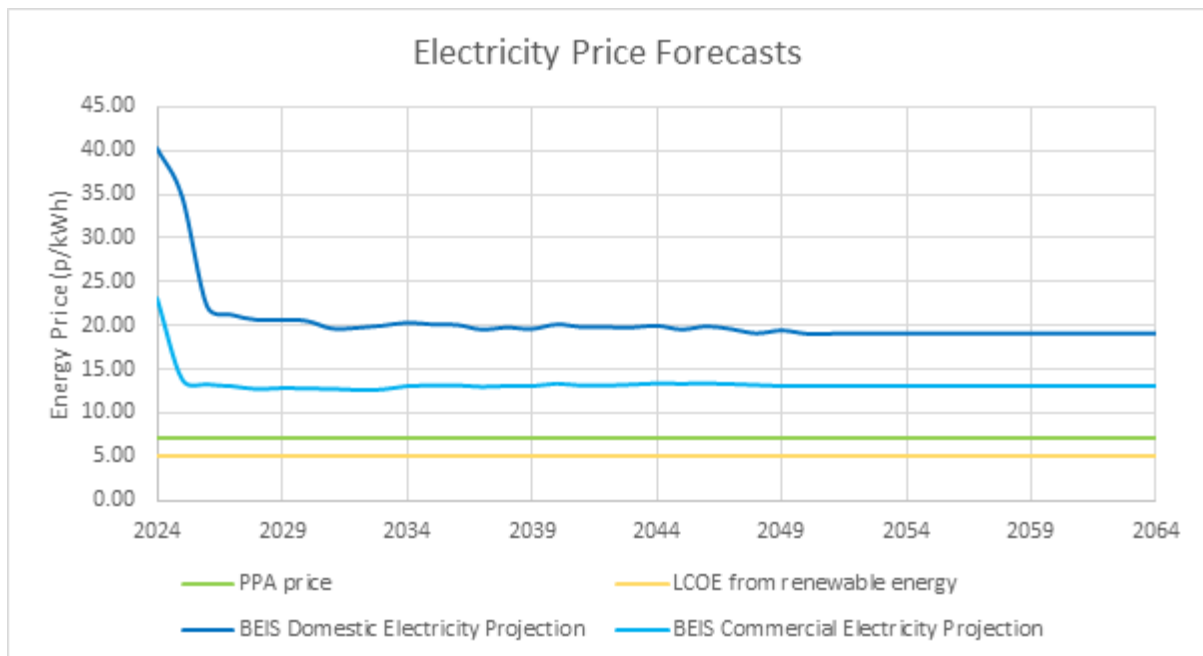


Figure 22: Electricity Price Forecasts

6.3 Capital Costs

An overview of the sources of data used to calculate capital costs is shown in Table 10.

Table 10: Capital cost data sources

ITEM	Source of data
Cost of minewater heat extraction	Townrock report
Heat Pump 1&2 (2x 1MW)	Solid Energy and Carrier
Backup gas/hydrogen ready boiler (1x 1MW)	Bosch boilers
Thermal storage (15,000 litres)	Based on similar project - £1,050/m ³
Plant room heat Exchangers	£3.5/kW value for heat exchangers. 2 1000kW heat exchangers required.
DH Pump	Infinitas
HIUs domestic size	£3,600 for each domestic HIU. 49 required for scernario 1 and 273 for scenario 2.
HIU's larger capacity for schools, and care homes	£6,802 for each commercial HIU. Has been assumed that 2 are needed for each building. Total of 10 and 12 required for scenarios 1 and 2 respectively.
Pipework	Using REHAU pipe costing values and Vital energy civil engineering costs
Energy Centre	£100/m ² with a total of 150m ² required for the energy centre
Control points	£500 per point with a total of 84 required
DHW cylinders, larger buildings	£5,000 per DHW cylinder for 5 commercial buildings .
Utility Connection-power	Northern Powergrid Connection cost calculator, assuming 3MWe connection, crossing 1 minor road, 50 metres from the existing network
MEP contract excluding heat pumps	Pure Renewables
Materials for M&E work	Pure Renewables

An overview of capital costs of scenario 1 is shown in Table 11.

Table 11 Scenario 1 overall capital costs

Capital cost for scenario 1	Solid Energy heat pump configuration	Carrier heat pump configuration
Cost of minewater heat extraction	£330,000	£330,000
Heat Pump 1&2 (2x 1MW)	£1,427,450	£431,972
Backup gas/hydrogen ready boiler (1x 1MW)	£42,000	£42,000
Thermal storage (15,000 litres)	£15,750	£15,750
Plant room heat Exchangers	£7,000	£7,000
DH Pump	£8,841	£8,841
HIUs domestic size	£176,400	£176,400
HIU's larger capacity for schools, and care homes	£68,020	£68,020
Pipework	£2,049,395	£2,049,395
Energy Centre	£15,000	£15,000
Flue	£20,000	£20,000
Control points	£46,200	£46,200
DHW cylinders, larger buildings	£25,000	£25,000
Utility Connection-power	£50,000	£50,000
MEP contract excluding heat pumps	£270,000	£270,000
Materials for M&E work	£270,000	£270,000
Prelims	15%	15%
Planning and Legals	10%	10%
Contingency	20%	20%
TOTAL	£7,318,363	£5,807,227

Configurations that use the Solid Energy heat pumps are considerably more expensive than configurations that use the Carrier heat pumps. Carrier offer lower prices as they are a larger company, however their heat pumps operate using less advanced technology that results in a slightly lower COP.

An overview of capital costs for scenario 2 is shown in Table 12.

Table 12:: Scenario 2 overall capital costs

Capital cost for scenario 2	Solid Energy heat pump configuration	Carrier heat pump configuration
Cost of minewater heat extraction	£330,000	£330,000
Heat Pump 1&2 (2x 1MW)	£1,427,450	£431,972
Backup gas/hydrogen ready boiler (1x 1MW)	£42,000	£42,000
Thermal storage (15,000 litres)	£15,750	£15,750
Plant room heat Exchangers	£7,000	£7,000
DH Pump	£8,841	£8,841
HIUs domestic size	£982,800	£982,800
HIU's larger capacity for schools, and care homes	£81,624	£81,624
Pipework	£7,256,655	£7,256,655
Energy Centre	£15,000	£15,000
Flue	£20,000	£20,000
Control points	£46,200	£46,200
DHW cylinders, larger buildings	£25,000	£25,000
Utility Connection-power	£50,000	£50,000
MEP contract excluding heat pumps	£270,000	£270,000
Materials for M&E work	£270,000	£270,000
Prelims	15%	15%
Planning and Legals	10%	10%
Contingency	20%	20%
TOTAL	£16,467,750	£14,956,614

As previously discussed, configurations with Solid Energy heat pumps cost more than with Carrier heat pumps. Most of the capital cost of scenario 2 is associated with the district heating network, as the network is quite large and would require approximately 5,977m of pipes. Relative costs based on the southern network have been used to estimate the cost of the northern district heating network. This adds some uncertainty, and is likely an overestimate as smaller pipes could be used due to the smaller heat loads of the domestic buildings in the northern cluster.

6.4 Operating Costs

6.4.1 Operation and Maintenance Costs

An overview of operational costs is shown in Table 13 below.

Table 13: Operational costs

Item	How costs have been derived	Annual cost estimate, 2024*
Coal authority heat abstraction fees	Cost estimate from CA, via Townrock Energy - £2 per 100m ³ of minewater.	Between £10,581/yr and £11,892/yr depending on the scenario and heat pump used
Heat pump maintenance	Cost estimate from Pure Renewables, Mar 22	£30,000/yr, for 2x 1MW heat pumps
Network maintenance	Cost estimate from Vital Energi, Mar 23.	£11,873/yr for scenario 1 and £30,498/year for scenario 2
Energy centre maintenance	Cost estimate from Vital Energi, Mar 23	£35,000/yr
Billing and metering.	Price list obtained from Switch2, Mar23	£5,500/yr for 49 homes, and 6 businesses.

6.5 Revenues

6.5.1 Carbon offsetting

Believe Housing, the owner of the domestic buildings of the northern and southern networks currently buys carbon offsets to maintain carbon neutrality¹⁶. If these buildings were to be connected these offset costs would be reduced significantly, leading to cost savings for Believe Housing. This has not been investigated as Believe housing appears to have only offset emissions from 2021 and it is unclear if they will continue to do so long term.

The UK has committed to becoming net zero by 2050 so commercial and residential buildings will be required to reduce emissions as far as possible, and offset any remainders. If Believe Housing plan to continue using gas boilers, there would be a cost of offsetting associated with this. The impact of this has not been included in this report.

¹⁶ <https://www.believehousing.co.uk/about-us/green-plan/>

6.6 Economic Results

6.6.1 Gas Boiler Counterfactual

Summaries of key results for the base case gas boiler counterfactual for the scenarios are shown in Table 14 and Table 15. Table 14 has been modelled using BEIS electricity price forecasts and Table 15 using PPA prices for electricity.

Table 14: Key parameters for scenarios with gas boiler counterfactual and BEIS electricity

BEIS and gas boiler counterfactual	Scenario 1		Scenario 2	
	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	7.32	5.81	16.47	14.96
Total Lifetime OPEX (£m)	12.98	15.55	15.12	17.09
NPV at 20 years (£m)	-5.82	-5.42	-13.44	-12.78
NPV at 30 years (£m)	-5.59	-5.81	-12.80	-12.61
NPV at 40 years (£m)	-5.25	-6.09	-12.05	-12.34
IRR at 40 years (%)	-6.59%	NA	-6.48%	-9.41%
Discounted payback period	0	0	0	0
Heat sales revenue (£m)	14.08	14.08	18.41	18.41

Table 15: Key parameters for scenarios with gas boiler counterfactual and PPA electricity

PPA and gas boiler counterfactual	Scenario 1		Scenario 2	
	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	7.32	5.81	16.47	14.96
Total Lifetime OPEX (£m)	8.89	10.18	10.50	11.48
NPV at 20 years (£m)	-4.17	-3.25	-11.57	-10.51
NPV at 30 years (£m)	-2.97	-2.37	-9.84	-9.01
NPV at 40 years (£m)	-1.67	-1.39	-8.01	-7.43
IRR at 40 years (%)	-1.35%	-1.48%	-3.26%	-3.41%
Discounted payback period	0.00	0.00	0.00	0.00
Heat sales revenue (£m)	14.08	14.08	18.41	18.41

It is worth noting that these economic simulations assume that the aquacultural load is charged according to the gas boiler counterfactual as the 2025 gas boiler ban only applies to newbuild properties. It is not clear whether the aquacultural business would be required to use a low carbon heat source, likely an ASHP. The aquacultural load could therefore be charged heat according to this higher ASHP heat price. This scenario has been modelled for scenario 1 in Table 16. The project then becomes economically viable with a PPA indicating a relatively easy way of making the project economically viable.

Table 16: Key parameters for scenarios with ASHP counterfactual for aquacultural load and gas boiler counterfactual for rest

ASHP for aquacultural load, gas boiler for rest of buildings	Scenario 1 with BEIS		Scenario 1 with PPA	
	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	7.32	5.81	7.32	5.81
Total Lifetime OPEX (£m)	12.98	15.6	8.89	10.2
NPV at 20 years (£m)	-3.81	-3.41	-2.16	-1.25
NPV at 30 years (£m)	-2.68	-2.90	-0.06	0.54
NPV at 40 years (£m)	-1.46	-2.30	2.12	2.40
IRR at 40 years (%)	-1.3%	-3.1%	1.5%	2.1%
Discounted payback period	0.00	0.00	30.27	26.93
Heat sales revenue (£m)	17.9	£17.9	17.9	17.9

6.6.2 Gas Boiler Counterfactual Sensitivity Analysis

Additional analysis has been carried out to identify how sensitive the economics of the various scenarios to key parameters. These key parameters were varied by $\pm 30\%$.

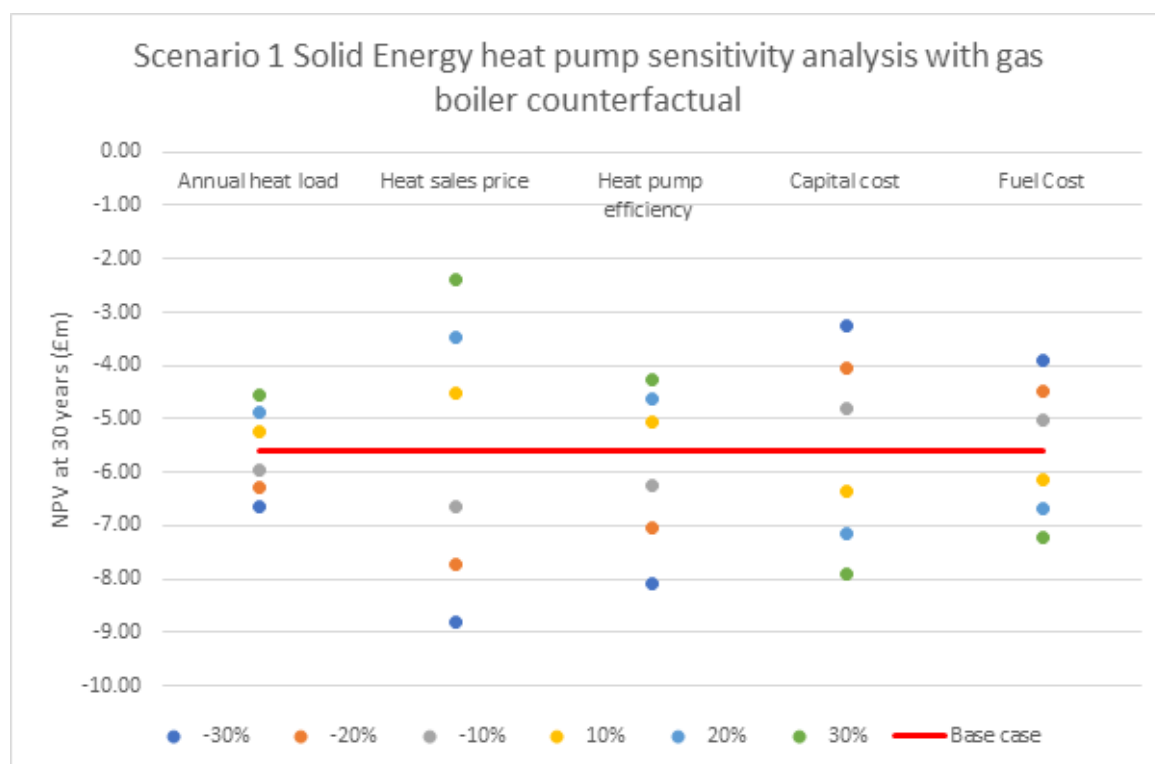


Figure 23: Scenario 1 Solid Energy heat pump sensitivity analysis with gas boiler counterfactual

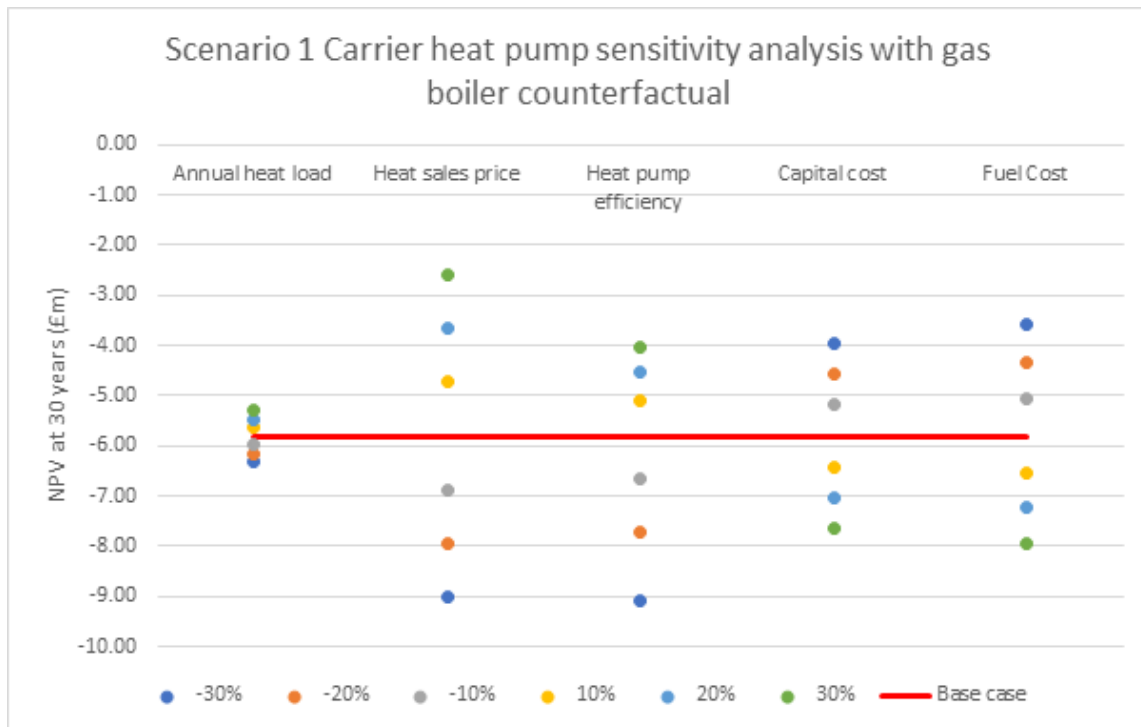


Figure 24: Scenario 1 Carrier heat pump sensitivity analysis with gas boiler counterfactual

6.6.3 Decentralised ASHP Counterfactual

Summaries of key results for the low carbon counterfactual of an ASHP for the scenarios are shown in Table 17 and Table 18. Table 17 has been modelled using BEIS electricity price forecasts and Table 18 using PPA prices for electricity. Scenario 1 becomes economically viable for all scenarios when a ASHP counterfactual is applied. Scenario 2 is however only economically viable when supplied with electricity in a PPA. This indicates that scenario 1 is significantly more economically viable.

Table 17: Key parameters for scenarios with ASHP counterfactual and BEIS electricity

BEIS and ASHP counterfactual	Scenario 1		Scenario 2	
	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	7.32	5.81	16.47	14.96
Total Lifetime OPEX (£m)	12.98	15.55	15.12	17.09
NPV at 20 years (£m)	-2.05	-1.65	-8.84	-8.18
NPV at 30 years (£m)	-0.14	-0.35	-6.28	-6.09
NPV at 40 years (£m)	1.86	1.02	-3.68	-3.96
IRR at 40 years (%)	1.40%	1.08%	-1.39%	-1.73%
Discounted payback period	30.71	32.67	0.00	0.00
Heat sales revenue (£m)	21.20	21.20	26.79	26.79

Table 18: Key parameters for scenarios with ASHP counterfactual and PPA electricity

PPA and ASHP counterfactual	Scenario 1		Scenario 2	
	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	7.32	5.81	16.47	14.96
Total Lifetime OPEX (£m)	8.89	10.18	10.50	11.48
NPV at 20 years (£m)	-0.40	0.51	-6.97	-5.91
NPV at 30 years (£m)	2.49	3.09	-3.32	-2.50
NPV at 40 years (£m)	5.44	5.72	0.36	0.94
IRR at 40 years (%)	3.50%	4.66%	0.12%	0.35%
Discounted payback period	21.37	18.05	39.02	37.28
Heat sales revenue (£m)	21.20	21.20	26.79	26.79

6.6.4 Decentralised ASHP Counterfactual Sensitivity Analysis

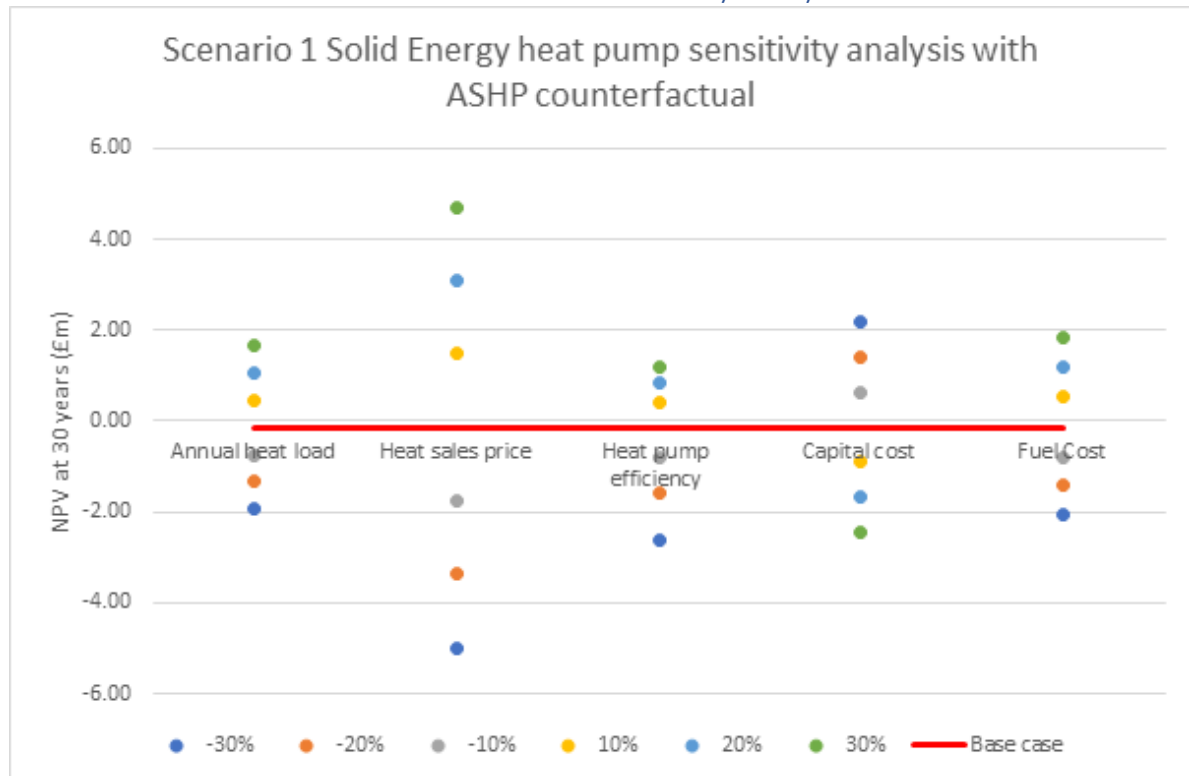


Figure 25: Scenario 1 Solid Energy heat pump sensitivity analysis with ASHP counterfactual

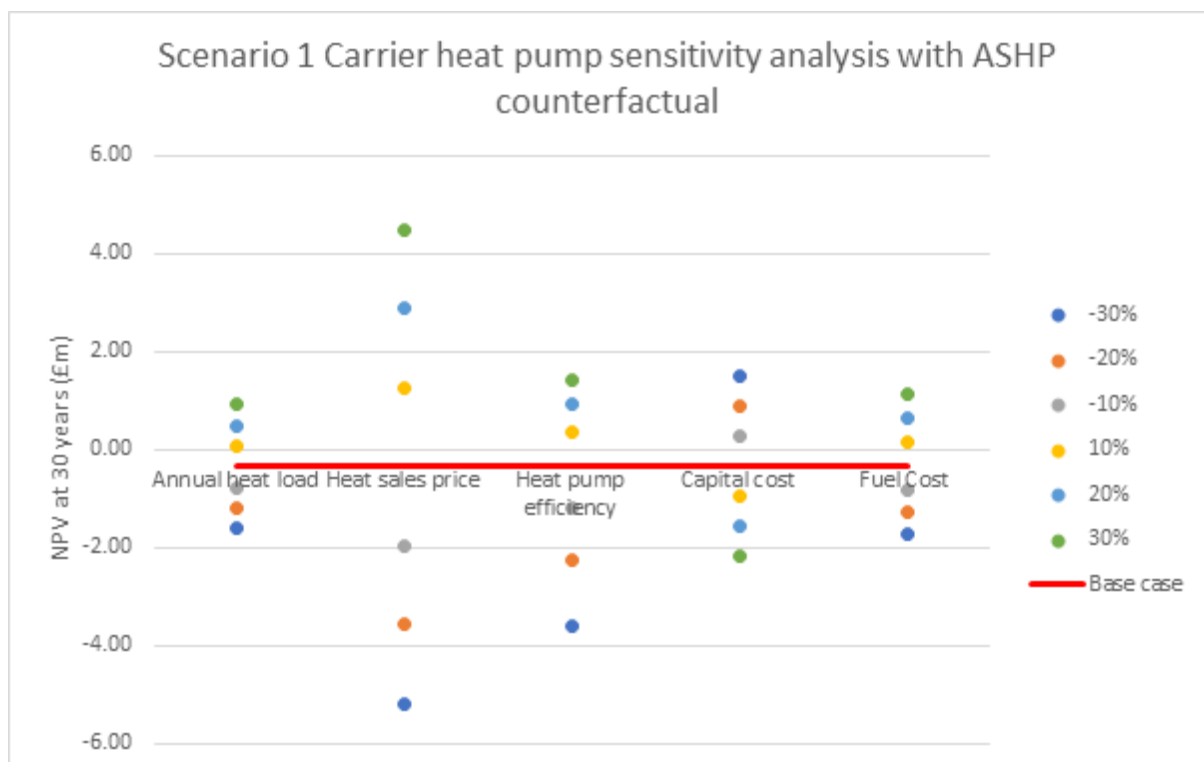


Figure 26: Scenario 2 Carrier heat pump with ASHP counterfactual

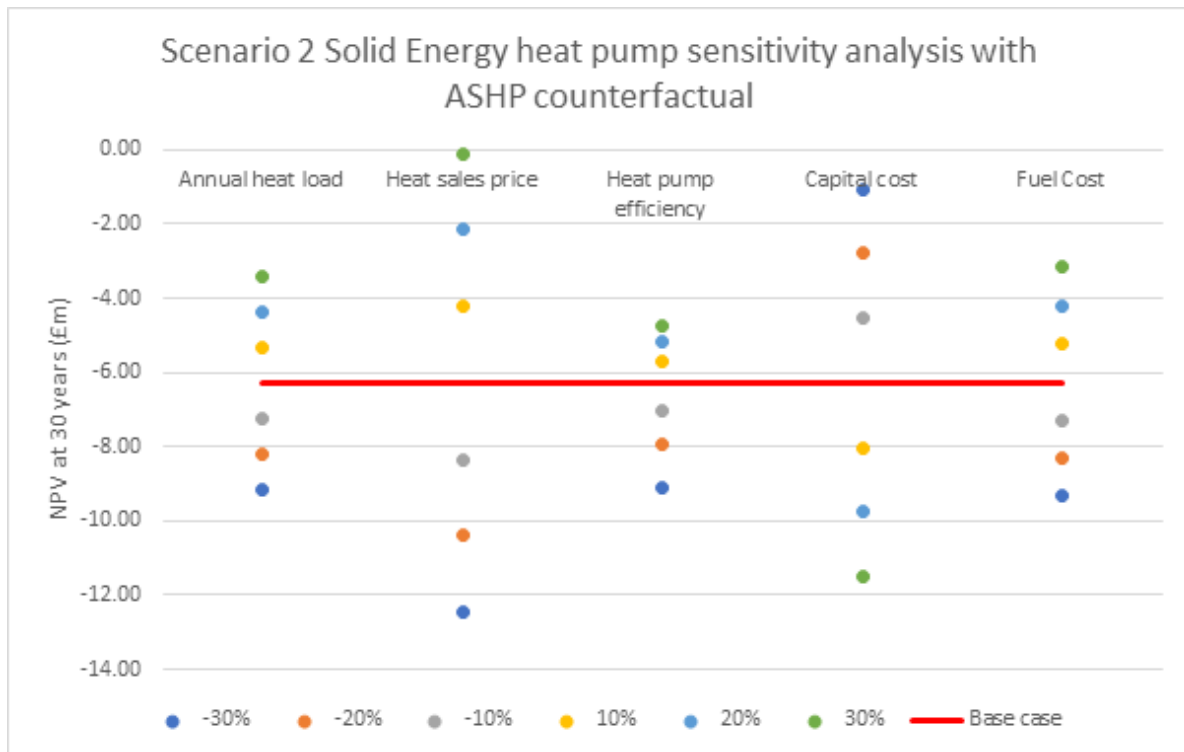


Figure 27: Scenario 2 Solid Energy heat pumps with ASHP counterfactual

6.7 Carbon emissions

6.7.1 Emission savings for DHN

The carbon assessment is presented as an absolute carbon emissions reduction against the counterfactual case. The counterfactual carbon emissions refer to the emissions generated by the connected buildings if they were not connected to the DHN. The emissions generated by the buildings varies between the two counterfactual options proposed in this report:

- **Isolated natural gas boilers:** Each individual building would continue to operate using individual gas boiler at 85% efficiency and fulfilling all of the heating demand.
- **Decentralised ASHP:** Each individual building would be heated using an individual ASHP with a COP of 2.2.

Carbon factors were assigned to both natural gas and electricity to calculate carbon emissions for each district heating scenario. The UK Government publishes carbon factors annually. The carbon factor of natural gas is consistent, as its chemical composition remains constant year on year. However, the carbon factor of electricity has been decreasing year on year as the electricity grid decarbonises. It is expected that this trend will continue as more renewable sources are added to the grid. Therefore, heat pumps could become less carbon intensive over time. The future power grid emissions factor published by BEIS was used to simulate future changes in the carbon emissions associated with electricity. This forecast is shown in Figure 28.

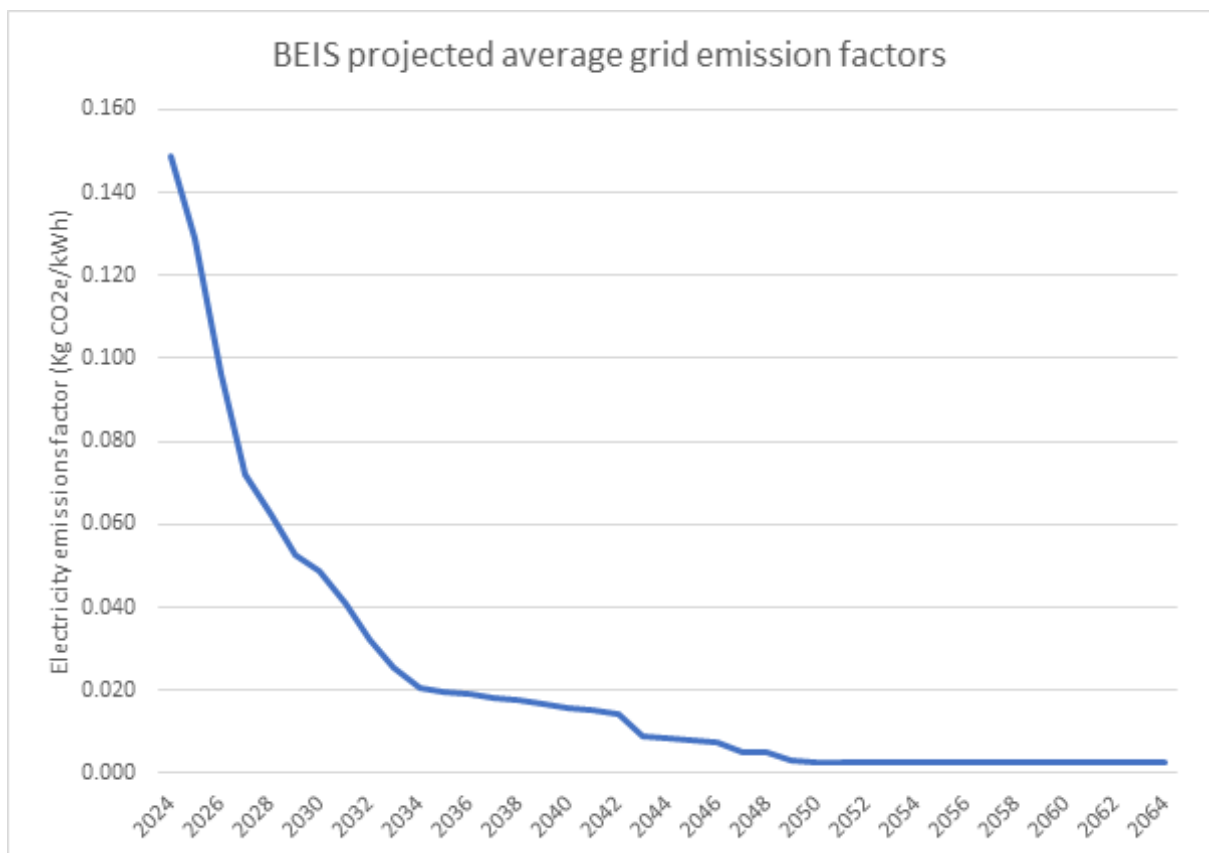


Figure 28: BEIS grid electricity emission factor projections

An overview of lifetime emissions of the district heating scenarios along with their counterfactuals is shown in Table 19 and is displayed graphically in Figure 29. It is clear that a district heating project would significantly reduce the emissions of Horden.

Table 19: Lifetime emissions of district heating network scenarios and counterfactuals

Variable	Scenario 1		Scenario 2	
	Solid Energy	Carrier	Solid Energy	Carrier
DHN lifetime emissions (Tonnes CO₂e)	3,373	3,848	4,929	5,298
DHN Carbon intensity over first 15 years (g/kWh)	18.61	22.42	25.50	28.53
DHN lifetime carbon intensity (g/kWh)	10.69	12.07	16.24	17.34
Gas boiler counterfactual lifetime emissions (Tonnes CO₂e)	62,078	62,078	60,572	60,572
ASHP counterfactual lifetime emissions (Tonnes CO₂e)	2,671	2,671	2,607	2,607
DHN emission savings after 2030 (Tonnes CO₂e)	50,792	50,599	48,266	48,115

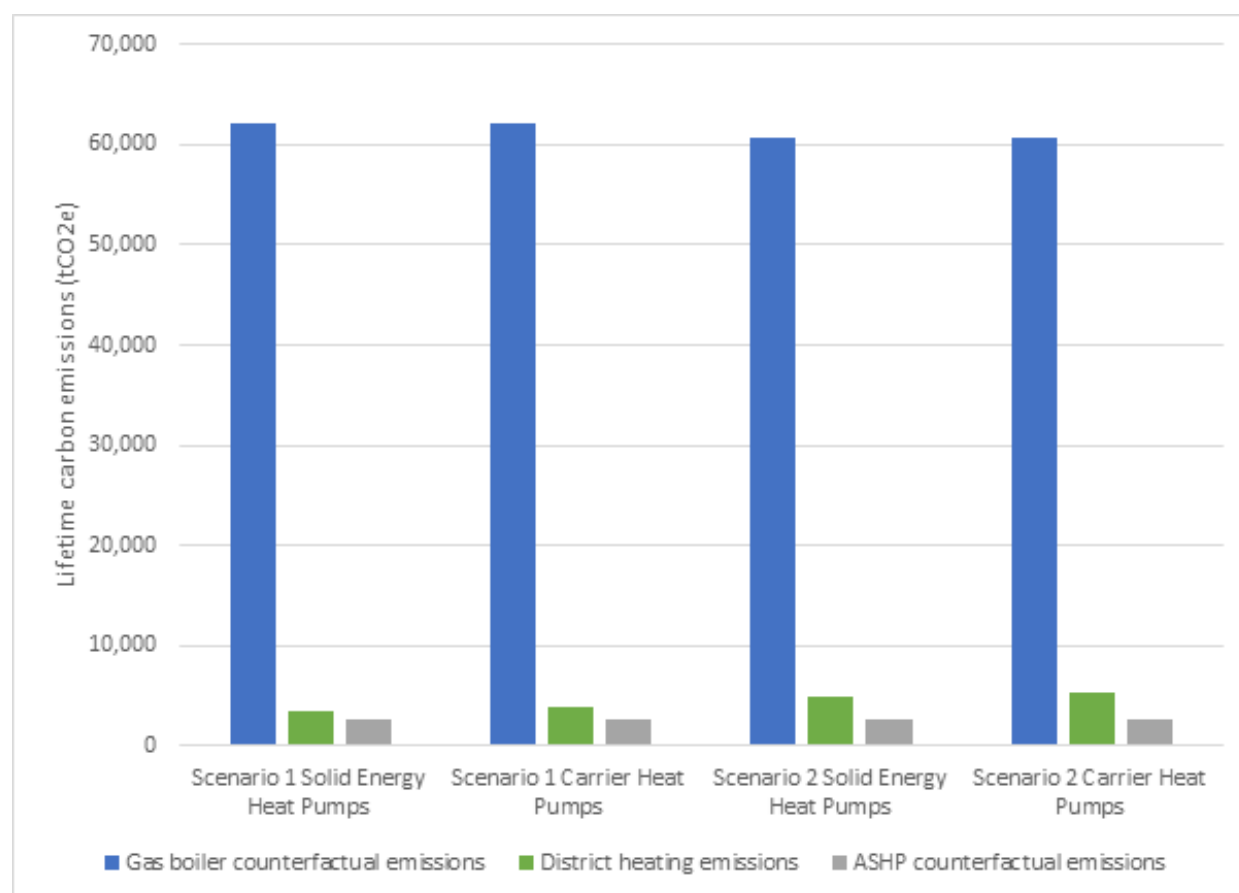


Figure 29:: Lifetime emissions of district heating network scenarios and counterfactuals

A more detailed breakdown lifetime emissions savings is shown in Table 20.

Table 20: Carbon emissions saved against different counterfactual options

Scenario	DHN lifetime emissions savings against gas boiler counterfactual (tCO ₂ e)	DHN lifetime emissions savings against ASHP counterfactual (tCO ₂ e)
Scenario 1 Solid Energy Heat Pumps	58,704	-702
Scenario 1 Carrier Heat Pumps	58,229	-1,177
Scenario 2 Solid Energy Heat Pumps	55,642	-2,323
Scenario 2 Carrier Heat Pumps	55,274	-2,691

8. Risk management

District heating networks are expensive and complicated, and as such require careful risk management throughout the stages of project development. Below is a summary of risks for this project. Risks are grouped into the following categories:

- Technical
- Business case
- Planning Consents, Permitting and Environment
- Stakeholders
- Construction and procurement
- Operation and maintenance
- Political

Each risk is given a score for both likelihood and severity, and the two scores are multiplied to give the overall risk score, which is colour coded red, amber, or green with red being the most severe, and green being the least. Mitigation measures for each risk are then specified.

Problem developing onsite renewables	Electricity prices for heat pump can't be reduced to levels required for the business plan to be viable.	5	4	20	Continue to investigate PPA options and aim for electricity prices to be as low as possible.	4	3	12
Budget overspend due to poor cost controls	Increased payback time, reduced IRR/NPV.	4	4	16	Undertake design reviews with relevant stakeholders. Consider procurement via a contractor to cover energy centre and networks	4	3	12
Budget underestimated due to unforeseen issues	Increased payback time, reduced IRR/NPV.	4	4	16	20% contingency added to the cost estimates in feasibility study	4	3	12
Resulting heat sales price too high for customers	Reduced heat sales, and revenues. Reduction in economic viability of the network.	4	4	16	Tight control on scheme costs is required through detailed business case development.			
Increase in costs (inflation)	Inflation results in capital costs being higher than expected. Social housing tenants struggle to pay for estimated heat demand if costs are passed on to heat consumer due to ongoing widespread inflationary pressures. Consequently, heat demand and associated income is reduced compared to modelled values.	4	4	16	Ongoing sensitivity testing and updated modelling work. Ongoing optimisation of business case, to ensure it is as lean as possible. Pursue aquaculture plan to diversify the heat demand. Continue to strengthen the business plan in all other ways possible- insulating properties, installing renewable electricity.			
BEIS forward projections for gas/electricity are showing prices lower than what transpire.	Higher gas prices mean that the project is more competitive against the counterfactual than indicated through BEIS price projections. Heat prices incorrectly estimated to be lower than they could be.	4	4	16	Plan for the worst-case scenario. Continue to update models based on best estimates. Observe changes in gas/power prices and Gov policy and look out for decoupling of electricity and gas prices. Consider development of onsite renewables, or renewables elsewhere in LA area, and investigate potential for PPA's, to provide low-cost power.			

Project can't be funded through GHNF	DCC would be responsible for sourcing 100% of capital funding.	4	3	12	It is currently believed that this project is eligible as an urban network selling more than 2GWh/yr of heat. Consultation with BEIS should continue to ensure this project is developed to be competitive with other applications. Other options for funding should also be considered on an ongoing basis.			
Planning, Consents, Permitting, and Environment								
Planning permission required for heat network	Potentially lengthy process of obtaining planning permission could delay the project.	3	3	9	Council to confirm at DPD stage whether permitted development rights cover installation of heating pipework in the public highways			
Failure to obtain planning permission for energy centre	The energy centre location would have to be changed. Piping schedule would have to be adapted. Additional pipe might be required, at additional cost and detriment to the business case.	4	3	12	Council to manage planning concerns going forward through engagement and appropriate legal obligations or conditions for all developments going through planning or as part of decarbonisation strategy for the existing buildings			
Issues agreeing heat access agreement with the CA	Results in delays, could result in heat price increases if charging regime increases beyond the £2/100m3 indicated.	4	4	16	Ongoing engagement with CA, and relevant politicians, to try and ensure a timely Heat Access Agreement, and affordable pricing mechanism.			
Stakeholders								
People no longer wish to connect	If heat loads do not materialise, the scheme may become difficult to operate economically. This could happen if people change mind, or private connections go out of business/change management	4	4	16	Recommend to lock in private customers into long term contracts where possible, and as soon as is appropriate (e.g. in planning agreements for new builds). Work to make affordable/attractive. Early engagement with developers,			

					improved planning policy to include connection obligation. Ensure scheme is viable and is not reliant on developments who are not obliged to connect.			
Trouble attracting a greenhouse grower due to high anti-social behaviour issues in Horden.	Might struggle to attract grower in first place. Could result in damage to a greenhouse if built. High replacement/maintenance costs for grower.	4	4	16	Strict security (e.g. high wire fence) Consider alternative sources that use energy (e.g. prawn farm / aquaculture). If no horticulture load, extend network to northern housing cluster instead.			
Horticulture/Aquaculture load not developed	Significant reduction in heat demand.	3	4	12	Extend network to northern housing cluster instead. Work with potential aquaculture developers (DEL/Bluewater Shrimps) to develop the concept further and refine likely heat demand and improve accuracy.			
Stakeholders oppose street works or post onerous requirements	Council time taken up in dealing with complaints	3	2	6	Project sponsor to manage interface through normal channels			
Operation and Maintenance								
Gas top-up boiler breaks down in winter	Heat pumps and any retained boilers would be required to make up the shortfall, and this would add cost.	3	2	6	Ensure regular servicing. Heat pumps could be throttled and turned up to make up the shortfall.			
Heat pumps break down	Gas boilers would be required to make up shortfall	3	3	9	Use gas boiler to make up short fall			
Political								
Uncertainty over Offset Costs	Council/Believe Housing change net-zero/offset plans, which impacts on heat network business plans, and	4	3	12	Continued engagement between all key council and project stakeholders.			

	likelihood of the project being viable.							
Existing gas boiler ban doesn't come into place in 2033.	The counterfactuals that this business case is based on are no longer relevant. This heat prices modelled here for the ASHP counterfactual would no longer be relevant, and customers would be unlikely to pay the modelled heat prices.	5	3	15	Continued engagement with BEIS/Gove sources, to keep up to date on developments and adapt plans as appropriate.			
Decarbonisation of energy grid	If grid electricity doesn't decarbonise quickly enough, then the carbon savings associated with this project (if it connects to the grid) won't be as high as projected	3	4	12	Continue to pursue development of onsite renewables, and/or low carbon PPA arrangement.			

9 Funding

9.1 Green Heat Network Fund

As part of the March 2020 budget announcement the UK Government have committed to £288m investment to fund the deployment of low carbon heat networks, including the expansion of existing networks. The Green Heat Network Fund (GHNF) scheme began accepting applications on 14th March 2022 and runs until 2025. The GHNF replaces the Heat Network Investment Project (HNIP) which came to an end in 2022.

The Green Heat Network Fund (GHNF) is capital grant fund open to the public and private sector in England that will capitalise on the progress and development made by the Heat Networks Investment Project (HNIP), by supporting the development of low and zero carbon (LZC) heat networks (including the supply of cooling).

9.2 Horden GHNF Eligibility

The details of the GHNF criteria are shown in Figure 30. Table 21 summarises whether each scenario for the Horden district heat network may or may not meet each criteria.

Subsidy Control	
 Maximum capex	Grant award requested up to but not including 50% of the combined total capex + commercialisation costs (with an upper limit of £1million for commercialisation)
 Capped award	The total 15-year kWh of heat/cooling forecast to be delivered may not exceed 4.5 pence of grant per kWh delivered (this figure will remain under review)
Metrics	
 Carbon gate	<100gCO ₂ e/kWh thermal energy delivered
 Customer detriment	The levelised tariff proposed in the application must be less than the counterfactual cost of low carbon heat
 Minimum demand	For urban networks a customer demand of >2GWh/yr (including existing customers). For rural networks a minimum number of 100 dwellings connected
 Social IRR	>3.5 % over a 40-year period , prior to grant intervention
 Non-heat/cooling cost inclusion	For projects including wider energy infrastructure in their application, the value of income generated/costs saved/wider subsidy obtained should be greater than or equal to the costs included.

Figure 30: GHNF criteria

Table 21: Criteria for GHNF application

Metric	Minimum Score	Scenario 1 – Solid Energy heat pump	Scenario 1 – Carrier heat pump	Scenario 2 – Solid Energy heat pump	Scenario 2 – Carrier heat pump
Carbon gate	100gCO ₂ e/kWh thermal energy delivered.	Lifetime emissions of 10.69gCO ₂ e/kWh	Lifetime emissions of 12.07gCO ₂ e/kWh	Lifetime emissions of 16.24gCO ₂ e/kWh	Lifetime emissions of 17.34gCO ₂ e/kWh
Customer detriment	Domestic and micro-business must not be offered a price of heat greater than a low carbon counterfactual for new buildings and a gas/oil counterfactual for existing buildings	Heat price has been set to gas counterfactual.	Heat price has been set to gas counterfactual.	Heat price has been set to gas counterfactual.	Heat price has been set to gas counterfactual.
Social IRR	Projects must demonstrate a social IRR of 3.5% or greater over a 40-year period				
Minimum demand	For urban networks a minimum end customer demand of 2Gwh/year. For rural networks, a minimum number of 100 dwellings	Heat demand of 7.05GWh/year	Heat demand of 6.88GWh/year	Heat demand of 6.88GWh/year	Heat demand of 6.88GWh/year
Maximum capex	Grant award requested up to but not including 50% of the combined total capex + commercialisation costs (with an upper limit of £1million for commercialisation)	Capex eligible for GHNF includes exclusions including (not limited to) commercialisation costs, equipment for burning biomass and biogas as primary heat supply sources, the costs of tertiary networks, and building efficiency improvements. Private wire networks and electricity generation equipment (eg PV and wind) can be eligible under some circumstances. Check guidance for full list of exclusions ¹⁷ .			
Capped award	The total 15-year kWh of heat/cooling forecast to be delivered will not exceed 4.5 pence of grant per kWh delivered (Subject to review by GHNF)	7,049,632kWh * 15 years * £0.0045 = £4,758,501	7,049,632kWh * 15 years * £0.0045 = £4,758,501	6,878,612kWh * 15 years * £0.0045 = £4,643,063	76,878,612kWh * 15 years * £0.0045 = £4,643,063
Non-heat/cooling cost incursion	For projects including wider energy infrastructure in their application, the value of income generated/costs saved/wider, subsidy obtained should be greater than or equal to the costs included.	N/A	N/A	N/A	N/A

¹⁷ https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1157238/green-heat-network-fund-r5-guidance.pdf

9.3 Other Funding Streams

An alternative funding stream for the project would be the Heat Network Efficiency Scheme (HNES). This scheme aims to deploy targeted funding into existing district heating and communal heating systems where outcomes are sub-optimal. Projects can apply for either capital grant funding (£3.8m) or revenue grant funding (£0.375m). The criteria for this funding stream is displayed in Figure 31. This would only be suitable for the current small district heating system in place at Robinson house.

Subsidy Control	
Maximum capex	
 (capital grant)	Up to but not including 50% of capital grant funding expenditure forecast
 (revenue grant)	Up to 100% of revenue grant funding expenditure forecast (£15,000-20,000 per grant funding application)
Metrics	
Eligible measures	
 (capital grant)	Grants to part-fund the delivery (installation) of eligible intervention/improvement measures to the energy centre, primary/secondary distribution network, tertiary network, metering
 (revenue grant)	Grants to fund procurement or mobilisation of external support to carry out Optimisation Studies. These studies will assess heat network projects to identify causes of sub-optimal performance and recommend costed intervention or improvement measures.

Figure 31: HNES criteria

10 Reducing electricity costs using renewable energy technology

10.1. Investing in onsite or locally sourced renewable energy

The findings of this project indicate that securing a source of renewable energy, either through developing onsite renewables or a PPA with a local generator, could help to reduce electricity costs.

The levelized cost of electricity (LCOE) is a measure of the average net present cost of electricity generation for an energy generator over its lifetime. In other words, it is the price at which you can be supplied with electricity if you invest in a renewable energy asset. An overview of LCOE from various sources according to when the project is commissioned is shown in Table 22. The values here have been adapted from the Electricity Generations Costs 2020 report from BEIS. Values have been adapted from 2018 prices into 2022 prices using inflation data from The Bank of England¹⁸. It is worth noting that even central BEIS values are likely underestimating LCOE as previous reports have indicated inaccuracy; the 2020 report showed that BEIS values were suddenly up to 50% less than the previous report in 2016¹⁹. Experience of working with renewable energy technology manufacturers and developers also confirms this as their LCOE for projects that have just been commissioned are up to 30% cheaper than central BEIS estimates for projects commissioning in 2025.

Table 22: Levelised cost of energy from various low carbon sources

LCOE (p/kWh) in 2022 prices					
Owned renewable asset	Estimate	2025	2030	2035	2040
Onshore wind	High	5.98	5.86	5.75	5.75
	Central	5.29	5.17	5.06	5.06
	Low	4.48	4.48	4.37	4.37
Offshore wind	High	7.24	6.09	5.52	5.06
	Central	6.55	5.40	4.94	4.60
	Low	5.86	4.94	4.48	4.14
Large scale solar	High	5.86	5.29	4.83	4.48
	Central	5.06	4.48	4.14	3.79
	Low	4.48	4.02	3.56	3.22
Solar 10-50kW	High	10.34	9.54	9.54	9.54
	Central	8.50	7.81	7.81	7.81
	Low	6.67	6.21	6.21	6.21
Landfill gas	High	10.34	10.34	10.34	10.34
	Central	7.70	7.70	7.70	7.70
	Low	5.06	5.06	5.06	5.06

The surrounding area close to the proposed location for the energy centre may be suitable for onsite renewable energy. Wind energy may be particularly suitable due to the clear fetch, and minimal obstructions on the coastline of Horden. A full wind power audit is outside of the scope of this report, however DEL have identified a local wind developer and

¹⁸ <https://www.bankofengland.co.uk/monetary-policy/inflation/inflation-calculator>

¹⁹ <https://www.carbonbrief.org/wind-and-solar-are-30-50-cheaper-than-thought-admits-uk-government/>

introduced them to DCC, and conversations are underway in relation to the potential for wind power at the site.

At the time of writing (April 2023) there is a moratorium preventing onshore wind developments, however changes in the political landscape could lead to the scrapping of the moratorium in the future. Should this change take place, DEL advise DCC to seriously consider onshore wind development, not only for this project, but for other DCC electrical demands, and as a potential source of income generation.

Figure 32 shows how the capacity factor of a wind turbine varies over the year. The capacity factor is a ratio of actual electrical output over a given time to the theoretical maximum electrical energy output. It can therefore be considered the average output over a period of time. Figure 32 shows that the wind resource is greatest during the winter, a period in which the heat demand of a district heating network would be highest. A wind turbine would therefore be a suitable electricity supply.

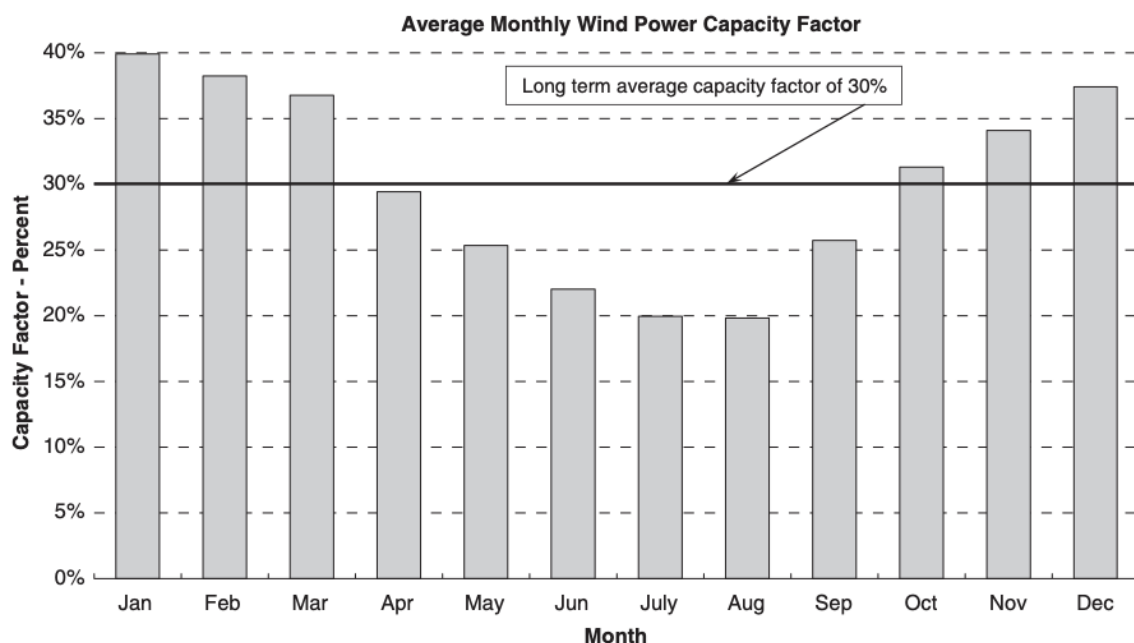


Figure 32: Wind turbine capacity factor over the year²⁰

Figure 33 shows the variation of a solar panel's capacity factor over the year. It is clear that this is not suited to the heat demand profile of a district heating network. Any solar development should therefore be sized to meet at least the baseload electrical demand. This would be approximately 130kW for scenario 1 and 50kW for scenario 2. It is recommended that a solar system is oversized so that the heat pumps can be supplied with cheap electricity during the spring and autumn. The optimisation of the solar energy system is not within the scope of this project and should be completed if the project develops further.

²⁰ <https://www.eci.ox.ac.uk/publications/downloads/sinden06-windresource.pdf>

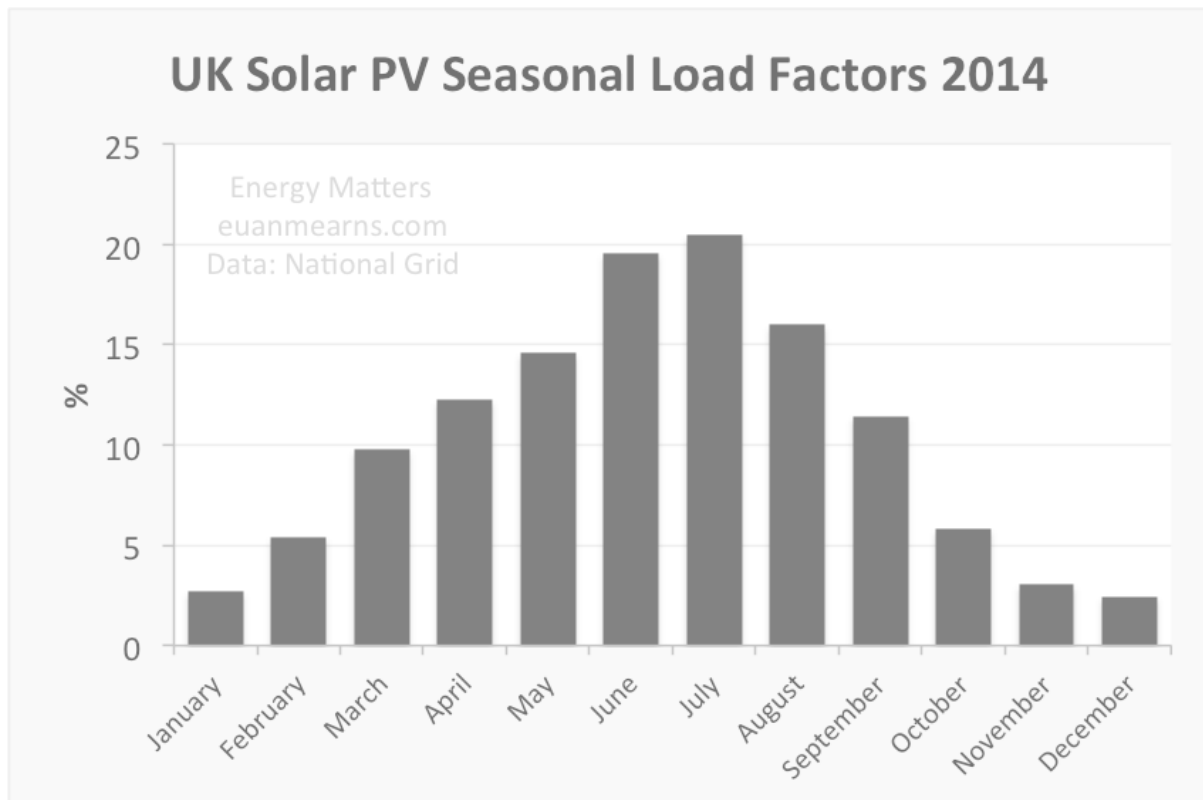


Figure 33: Solar panel capacity factor over the year²¹

If the aquacultural load is developed, any renewable system could be designed to supply it with electricity. This would aid the economics of the project further as electricity costs are high, especially when compared to renewable energy generation costs.

If the funded renewable technology is not onsite or connected via private wire, transmission costs will need to be paid to Northern Power Grid. Their rates change according to time of use and details are shown in Table 23.

Table 23: Transmission costs for different time bands²²

Time bands			
Time period	Red Time Band	Amber Time Band	Green Time Band
Monday to Friday (including bank holidays)	16:00 to 19:30	08:00 to 16:00 19:30 to 22:00	00:00 to 08:00 22:00 to 24:00
Saturday and Sunday			00:00 to 24:00
Transmission cost for band (p/kWh)	5.897	0.844	0.168

Transmission costs can be reduced using the thermal store as it can be charged when electricity transmission costs are cheaper and then discharged during periods when transmission costs are expensive (red band). Using the thermal store has been estimated to result in average transmission costs of 0.82p/kWh.

²¹ <http://euanmearns.com/uk-solar-pv-vital-statistics/>

²² [https://www.northernpowergrid.com/sites/default/files/assets/Northern Powergrid %28Northeast%29 - 2023-24 LC14 Charging Statement - v0.3.pdf](https://www.northernpowergrid.com/sites/default/files/assets/Northern%20Powergrid%20Northeast%20-2023-24%20LC14%20Charging%20Statement%20-v0.3.pdf)

10.2 Power purchase agreements

A power purchase agreement (PPA) is a long-term contract between an electricity generator and a customer, usually a utility, government or company. A PPA would allow the project to be powered using electricity on a fixed long-term price that would likely be lower than market prices. In addition, if the PPA was with a renewable energy provider, the electricity supplied would be low carbon electricity with very little emissions. The average PPA price for a 10-year contract as of February 2023 is approximately 7.08p/kWh²³. With transmission costs, electricity could therefore be supplied to the site at approximately 7.8p/kWh.

An onsite PPA could also be made between the council and a renewable energy developer. Here, the council would allow the developer rights to build an asset on their land and in return be supplied with cheaper renewable electricity. This would also reduce costs as transmission fees would no longer be required.

²³ <https://app.pexapark.com/api/ppa-times/31/document>

11 Conclusions and next steps

The findings from this report conclude that there could be an economic case for the development of a district heating network under certain conditions. The identified existing care homes and proposed aquacultural load represent sizeable anchor loads which could be connected to the network. If the aquacultural load is not developed a northern network could be developed to connect the project to the large housing estate of 449 houses as well as Our Lady Star of the Sea School. This northern heating network is less economically viable when compared to connecting to an aquacultural load, due to the amount of pipe and number of connections required. Therefore, an aquacultural load may be a preferable option.

Techno-economic modelling compared the district heating network scenarios to two counterfactuals, individual gas boilers and individual ASHPs. Against both, scenario 1 was more economically viable. This is due to the heat demand density in the north of Horden being less than in the south. In addition to this, in scenario 1 a aquacultural load has been assumed to be built on site by the energy centre. This aids the economic of the project as it can easily be connected to the project without requiring significant quantities of pipe. The aquacultural load is also a major anchor load that has been modelled to have a baseline heat demand of 500kW. This further aids the projects as there is a heat demand even in the summer, when the rest of the network would require just heat for domestic hot water.

Scenario 1 has not been found to be economically viable when compared to a gas boiler counterfactual, even with a PPA agreement and is only just economically viable when all electricity is supplied by a wind turbine at the LCOE.

Gas boiler counterfactual	Scenario 1 with BEIS		Scenario 1 with PPA		Scenario 1 with onshore wind at LCOE	
	Solid Energy	Carrier	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	7.32	5.81	7.32	5.81	7.33	5.81
Total Lifetime OPEX (£m)	12.98	15.55	8.89	10.18	7.71	8.64
NPV at 20 years (£m)	-5.82	-5.42	-4.17	-3.25	-3.62	-2.54
NPV at 30 years (£m)	-5.59	-5.81	-2.97	-2.37	-2.13	-1.27
NPV at 40 years (£m)	-5.25	-6.09	-1.67	-1.39	-0.55	0.08
IRR at 40 years (%)	-6.59%	NA	-1.35%	-1.48%	-0.41%	0.08%
Discounted payback period	0	0	0.00	0.00	0	39.42
Heat sales revenue (£m)	14.08	14.08	14.08	14.08	14.08	14.08

As the aquacultural load is yet to be built it may be possible to charge it more expensive heat prices before the gas boiler ban occurs. In 2026 new buildings must be built with a low carbon heating technology. It is however, unclear if this ban would apply for a aquacultural load. The economic outcomes of charging the aquacultural load ASHP heat prices while charging the rest of the buildings according to gas boiler heat prices is shown below.

ASHP for aquacultural load, gas boiler for rest of buildings	Scenario 1 with BEIS		Scenario 1 with PPA		Scenario 1 with onshore wind at LCOE	
	Solid Energy	Carrier	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	7.32	5.81	7.32	5.81	7.32	5.81
Total Lifetime OPEX (£m)	12.98	15.6	8.89	10.2	7.71	8.64
NPV at 20 years (£m)	-3.81	-3.41	-2.16	-1.25	-1.61	-0.53
NPV at 30 years (£m)	-2.68	-2.90	-0.06	0.54	0.78	1.60
NPV at 40 years (£m)	-1.46	-2.30	2.12	2.40	3.25	3.87
IRR at 40 years (%)	-1.3%	-3.1%	1.5%	2.1%	2.2%	3.2%
Discounted payback period	0.00	0.00	30.27	26.93	26.72	22.39
Heat sales revenue (£m)	17.9	17.9	17.9	17.9	17.9	17.9

Gas boiler will however, at some point be banned, potentially as early as 2033. The economic impact of when this ban occurs has not been modelled. The table below however, shows the economic results of the project if heat is charged according to 95% of the ASHP counterfactual heat price. Scenario 1 now becomes economically viable even when supplied with electricity from the grid. This indicates that under certain economic conditions, a district heating network would likely be the most economical low carbon technology.

ASHP counterfactual	Scenario 1 with BEIS		Scenario 1 with PPA		Scenario 1 with onshore wind at LCOE	
	Solid Energy	Carrier	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	7.32	5.81	7.32	5.81	7.32	5.81
Total Lifetime OPEX (£m)	12.98	15.55	8.89	10.18	7.71	8.64
NPV at 20 years (£m)	-2.05	-1.65	-0.40	0.51	0.145	1.23
NPV at 30 years (£m)	-0.14	-0.35	2.49	3.09	3.32	4.18

NPV at 40 years (£m)	1.86	1.02	5.44	5.72	6.57	7.19
IRR at 40 years (%)	1.40%	1.08%	3.50%	4.66%	4.1%	5.6%
Discounted payback period	30.71	32.67	21.37	18.05	19.55	15.88
Heat sales revenue (£m)	21.20	21.20	21.37	18.05	21.37	18.05

It is clear that connecting the project to a renewable energy source would significantly improve the economics of all scenarios. In addition to this, if a aquacultural load is developed it will likely have a large electrical demand and so an additional revenue stream would become available. It is however, recommended that the heat and electricity price to which the aquacultural load is carefully thought about to ensure that it is connected, If the aquacultural load is not connected, the project becomes significantly less economically viable as shown in scenario 2.

Scenario 2 is significantly less economically viable due to the large quantites of pipe required to connect to a housing estate which has many small heat loads spread over it. This significantly reduces the economics of the project.

Gas boiler counterfactual	Scenario 2 with BEIS		Scenario 2 with PPA	
	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	16.47	14.96	16.47	14.96
Total Lifetime OPEX (£m)	15.12	17.09	10.50	11.48
NPV at 20 years (£m)	-13.44	-12.78	-11.57	-10.51
NPV at 30 years (£m)	-12.80	-12.61	-9.84	-9.01
NPV at 40 years (£m)	-12.05	-12.34	-8.01	-7.43
IRR at 40 years (%)	-6.48%	-9.41%	-3.26%	-3.41%
Discounted payback period	0	0	0.00	0.00
Heat sales revenue (£m)	18.41	18.41	18.41	18.41

When scenario 2 is supplied using an ASHP and BEIS electricity it is not economically viable. It is therefore unlikely that this district heating network is the most economically viable low carbon solution.

ASHP counterfactual	Scenario 2 with BEIS		Scenario 2 with PPA	
	Solid Energy	Carrier	Solid Energy	Carrier
Total Lifetime CAPEX (£m)	16.47	14.96	16.47	14.96
Total Lifetime OPEX (£m)	15.12	17.09	10.50	11.48
NPV at 20 years (£m)	-8.84	-8.18	-6.97	-5.91
NPV at 30 years (£m)	-6.28	-6.09	-3.32	-2.50
NPV at 40 years (£m)	-3.68	-3.96	0.36	0.94
IRR at 40 years (%)	-1.39%	-1.73%	0.12%	0.35%
Discounted payback period	0.00	0.00	39.02	37.28
Heat sales revenue (£m)	26.79	26.79	26.79	26.79

A smaller district heating network could potentially be installed at the school to connect the housing estate. This would benefit from being closer to the housing estate and therefore require less pipe.

11.1 Key recommendations

Below is a list of key recommendations that would benefit this district heating study:

- Further review of the aquacultural heat demand
- Site survey's to further asses existing building's current heating plants and estimate the date of replacement as well design of connection to the heat network
- Investigation of renewables close to or onsite. The recommended technology is wind due to it more closely matching the heat demand profile of the district heating network.